UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 40-F

¨ Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934; or
þ Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended: December 31, 2016
Commission file number: No. 0-50832

Vermilion Energy Inc.

(Exact name of registrant as specified in its charter)

Alberta

(Province or other jurisdiction of incorporation or organization)

1311

(Primary standard industrial classification code number)

N/A

(I.R.S. employer identification number)

3500, 520 – 3rd Avenue S.W.
Calgary, Alberta T2P 0R3 Canada
(403) 269-4884

(Address and telephone number of registrant's principal executive office)

National Corporate Research, Ltd.
225 West 34th Street, Suite 910
New York, New York 10122 U.S.A.
(212) 947-7200

(Name, address and telephone number of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class:	Common Shares, no par value (together with associated common share purchase rights)	Name of each exchange on which registered:	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act: **None**

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

For annual reports, indicate by check mark the information filed with this form:

þ **Annual Information Form** þ **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: **118,262,708 shares**

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days.

þ **Yes** ¨ No

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

¨ **Yes** ¨ No

DOCUMENTS FILED PURSUANT TO GENERAL INSTRUCTIONS

In accordance with General Instruction B.(3) of Form 40-F, the Registrant has filed the following documents as part of this Annual Report on Form 40-F, as set forth in the Exhibit Index attached hereto:

Exhibit 99.1 - Annual Information Form for the fiscal year ended December 31, 2016
Exhibit 99.2 - Management's Discussion and Analysis for the fiscal year ended December 31, 2016; and
Exhibit 99.3 - Audited Annual Financial Statements for the fiscal year ended December 31, 2016

In accordance with General Instruction D.(9) of Form 40-F, the Registrant has filed the written consent of certain experts named in the foregoing Exhibits as Exhibit 99.5 and the written consent of its Independent Registered Public Accounting Firm as Exhibit 99.4, as set forth in the Exhibit Index attached hereto.

DISCLOSURE CONTROLS AND PROCEDURES

A. Evaluation of Disclosure Controls and Procedures

Vermilion Energy Inc. (the "Registrant") maintains disclosure controls and procedures designed to ensure that information required to be disclosed in the Registrant's filings under the Securities Exchange Act of 1934, as amended (the "Exchange Act") is recorded, processed, summarized and reported within the time period specified in the rules and forms of the Securities and Exchange Commission (the "Commission"). Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrant in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. The Registrant's Chief Executive Officer and Chief Financial Officer, after having evaluated the effectiveness of the Registrant's disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report have concluded that, as of such date, the Registrant's disclosure controls and procedures are effective.

B. Management's Annual Report on Internal Control Over Financial Reporting

See page 3 of the 2016 Audited Financial Statements included as Exhibit 99.3 to this report.

C. Auditor Attestation

See page 5 of the 2016 Audited Financial Statements included as Exhibit 99.3 to this report.

D. Changes in Internal Control Over Financial Reporting

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

NOTICES REQUIRED BY RULE 104 OF REGULATION BTR

None

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's Board of Directors has determined that it has at least one audit committee financial expert (as such term is defined in the rules and regulations of the Commission) serving on its Audit Committee. Catherine L. Williams has been determined to be such audit committee financial expert and is independent (as such term is defined by the New York Stock Exchange's corporate governance standards).

The Commission has indicated that the designation of Catherine L. Williams as an audit committee financial expert does not make her an "expert" for any purpose, impose on her any duties, obligations or liability that are greater than the duties, obligations or liability imposed on her as a member of the Audit Committee and the Board of Directors in absence of such designation, or affect the duties, obligations or liability of any other member of the Audit Committee or Board of Directors.

CODE OF ETHICS

The Registrant has adopted a written “code of ethics” (as that term is defined in Form 40-F) that applies to its directors, officers and employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions. A copy of such code of ethics is available upon request or on the Registrant’s website at www.vermilionenergy.com. Other than in respect of certain administrative amendments reflecting organizational changes and changes to Vermilion’s business practices, in 2016, there were no amendments to the code of ethics or waivers, including implicit waivers, from any provision of the code of ethics.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

See page 53 of the Annual Information Form for the year ended December 31, 2016 included as Exhibit 99.1 to this report.
The Audit Committee pre-approves all audit related fees. The auditors present the estimate for the annual audit related services to the Audit Committee for approval prior to undertaking the annual audit of the financial statements.

All non-audit fees were pre-approved by the Audit Committee and none were approved on the basis of the de minimis exemption set forth in Rule 2-01(c)(7)(i)(C) of Regulation S-X .

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has not entered into any off balance sheet arrangements that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

Payments due by period as at December 31, 2016 (Cdn $000’s)

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt	-	1,335,600	-	-	1,335,600
Operating lease obligations	12,683	21,087	18,228	1,657	53,655
Ship or pay agreement relating to the Corrib project	4,241	7,331	6,074	31,427	49,073
Purchase obligations	9,007	3,852	7	-	12,866
Drilling and service agreements	5,437	9,850	20,511	26,870	62,668
Total contractual obligations and commitments	31,368	1,377,720	44,820	59,954	1,513,862

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant's Board of Directors has a separately designated standing Audit Committee established in accordance with Section 3(a)(58)(A) of the Exchange Act which satisfies the requirements of Exchange Act Rule 10A-3. The Registrant's Audit Committee is comprised of Catherine L. Williams (Chair), Claudio A. Ghersinich, Larry J. Macdonald and Robert Michaleski, all of whom, in the opinion of the Registrant's Board of Directors are independent (as determined under Rule 10A-3 of the Exchange Act and the corporate governance standards of the NYSE) and are financially literate.

NYSE STATEMENT OF GOVERNANCE DIFFERENCES

As a Canadian corporation with securities listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), the Registrant is required to comply with all applicable Canadian requirements adopted by the Canadian Securities Administrators and the TSX, and applicable rules for foreign private issuers adopted by the Commission which give effect to the provisions of the Sarbanes-Oxley Act of 2002 ("Sarbanes-Oxley").

The Registrant's corporate governance practices meet or exceed all applicable Canadian and Sarbanes-Oxley requirements and also incorporate many "best practices" derived from those required to be followed by U.S. domestic companies under the NYSE listing standards. In accordance with Section 303A.11 of the NYSE Listed Company Manual, the Registrant has prepared a summary of the significant ways in which its corporate governance practices differ from those required to be followed by U.S. domestic companies under the NYSE's corporate governance standards, which is accessible on the Registrant's website at *http://www.vermilionenergy.com/about/governance.cfm*.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

The Registrant has previously filed with the Commission a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

Any change to the name or address of the Registrant's agent for service shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of the Registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

VERMILION ENERGY INC (the Registrant)

Date: February 27, 2017

By: */s/ ("Curtis W. Hicks")*
Curtis W. Hicks
Executive Vice President and Chief Financial Officer

EXHIBIT INDEX

The following exhibits have been filed as part of this annual report:

Exhibits	Description
99.1	Annual Information Form for the Year Ended December 31, 2016
99.2	Management's Discussion and Analysis from the 2016 Annual Report to Shareholders
99.3	Audited Annual Financial Statements for the Year Ended December 31, 2016
99.4	Consent of Independent Registered Public Accounting Firm
99.5	Consent of Independent Petroleum Consultants
99.6 (2)	Officers' Certification pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
99.7 (2)	Officers' Certification pursuant to Rule 13a-14(b) or Rule 15d-14(b) of the Securities Exchange Act of 1934 and Section 1350 of Chapter 63 of Title 18 of the United States Code

Exhibit 99.1

2016 ANNUAL INFORMATION FORM

For the year ended December 31, 2016

Dated February 24, 2017

NOTE: GRAPHICS NOT REQUIRED TO APPLY TO THIS PAGE

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GLOSSARY OF TERMS

In addition to terms defined elsewhere in this annual information form, the following are defined terms used in this annual information form:

"2003 Arrangement" means the plan of arrangement under the ABCA involving the Trust, Vermilion Resources Ltd., Clear Energy Inc. and Vermilion Acquisition Ltd., which was completed on January 22, 2003;

"ABCA" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;

"AGCA" means Alberta Gas Cost Allowance;

"AIF" means this Annual Information Form and the appendices attached hereto;

"Affiliate" when used to indicate a relationship with a person or company, has the same meaning as set forth in the *Securities Act* (Alberta);

"Board of Directors" or **"board"** means the board of directors of Vermilion;

"CGUs" means cash generating units and based on management's judgement, represents the lowest level at which there is identifiable cash inflows that are largely independent of the cash inflows of other groups of assets or properties;

"Common Shares" means a common share in the capital of the Company;

"Contingent Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies;

"Control" means, with respect to control of a body corporate by a person, the holding (other than by way of security) by or for the benefit of that person of securities of that body corporate to which are attached more than 50% of the votes that may be cast to elect directors of the body corporate (whether or not securities of any other class or classes shall or might be entitled to vote upon the happening of any event or contingency) provided that such votes, if exercised, are sufficient to elect a majority of the board of directors of the body corporate;

"Conversion Arrangement" means the plan of arrangement effected on September 1, 2010 under section 193 of the ABCA pursuant to which the Trust converted from an income trust to a corporate structure, and Unitholders exchanged their Trust Units for common shares of the Company on a one-for-one basis and holders of exchangeable shares of VRL received 1.89344 common shares for each exchangeable share held;

"Depletion units" means groups of assets or properties that are within a specific production area and have similar economic lives. Depletion units represent the lowest level of disaggregation for which Vermilion accumulates costs for the purposes of calculating and recording depletion;

"Dividend" means a dividend paid by Vermilion in respect of the common shares, expressed as an amount per common share;

"Dividend Payment Date" means any date that Dividends are paid to Shareholders, generally being the 15th day of the calendar month following the determination of a Dividend Record Date;

"Dividend Record Date" means the last day of each calendar month or such other date as may be determined from time to time by the Company;

"GLJ" means GLJ Petroleum Consultants Ltd., independent petroleum engineering consultants of Calgary, Alberta;

"GLJ Report" means the independent engineering reserves evaluation of certain oil, NGL and natural gas interests of the Company prepared by GLJ dated February 1, 2017 and effective December 31, 2016;

"GLJ Resource Assessment" means the independent engineering resource evaluation prepared by GLJ to assess contingent and prospective resources across all of the Company's key operating regions with an effective date of December 31, 2016;

"IFRS" means International Financial Reporting Standards, as issued by the International Accounting Standards Board;

"Income Tax Act" or **"Tax Act"** means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1. (5th Supp.), as amended, including the regulations promulgated thereunder;

"Meeting" means the annual meeting of Shareholders of the Company to be held on April 28, 2017 (or, if adjourned, such other date on which the meeting is held);

"NYSE" means New York Stock Exchange;

"PNG" means Petroleum and Natural Gas properties and equipment;

"PRRT" means Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia;

"Plan" means the Premium Dividend™ and Dividend Reinvestment Plan of the Company dated effective February 27, 2015, as amended or supplemented from time to time;

"Prospective Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects;

"Rights Plan" means the Shareholder Rights Plan of the Company;

"Senior Unsecured Notes" means the $225 million aggregate principal amount of five year senior unsecured notes of the Company issued February 10, 2011 and repaid on February 10, 2016;

"Shareholders" means holders from time to time of the Company's common shares;

"Shareholder Rights Plan Agreement" means the Shareholder Rights Plan Agreement dated September 1, 2010 between the Company and Computershare Trust Company of Canada establishing the Rights Plan, as amended and restated as of May 1, 2013 and as amended or supplemented from time to time;

"Subsidiary" means, in relation to any person, any body corporate, partnership, joint venture, association or other entity of which more than 50% of the total voting power of common shares or units of ownership or beneficial interest entitled to vote in the election of directors (or members of a comparable governing body) is owned or controlled, directly or indirectly, by such person;

"TSX" means the Toronto Stock Exchange;

"Trust" means Vermilion Energy Trust, an unincorporated open-ended investment trust governed by the laws of the Province of Alberta that was dissolved and ceased to exist pursuant to the Conversion Arrangement;

"Trust Unit" means units in the capital of the Trust;

"Unitholders" means former unitholders of the Trust;

"Vermilion" or the **"Company"** means Vermilion Energy Inc. and where context allows, its consolidated business enterprise, except that a reference to "Vermilion" prior to the date of the Conversion Arrangement means the consolidated business enterprise of the Trust, unless otherwise indicated; and

"VRL" means Vermilion Resources Ltd., previously a subsidiary of the corporation.

Conventions

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with IFRS.

Abbreviations

Oil and Natural Gas Liquids	
bbl	barrel
Mbbl	thousand barrels
bbl/d	barrels per day
NGLs	natural gas liquids
Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMBtu	million British Thermal Units
Other	
API	American Petroleum Institute
°API	An indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28 °API or higher is generally referred to as light crude oil.
boe	barrel of oil equivalent
M$	thousand dollars
MM$	million dollars
Mboe	1,000 barrels of oil equivalent
MMboe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
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
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid

Conversion

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
bbls	Cubic metres	0.159
Cubic metres	bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements included or incorporated by reference in this annual information form may constitute forward looking statements or financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this annual information form may include, but are not limited to:

- capital expenditures;
- business strategies and objectives;
- estimated reserve quantities and the discounted present value of future net cash flows from such reserves;
- petroleum and natural gas sales;
- future production levels (including the timing thereof) and rates of average annual production growth, estimated contingent resources;
- exploration and development plans;
- acquisition and disposition plans and the timing thereof;
- operating and other expenses, including the payment of future dividends;
- royalty and income tax rates;
- the timing of regulatory proceedings and approvals; and
- the estimate of Vermilion's share of the expected natural gas production from the Corrib field.

Such forward-looking statements or information are based on a number of assumptions all or any of which may prove to be incorrect. In addition to any other assumptions identified in this document, assumptions have been made regarding, among other things:

- the ability of the Company to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally;
- the ability of the Company 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 the Company 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 development activities.

Although the Company believes that the expectations reflected in such forward looking statements or information are reasonable, undue reliance should not be placed on forward looking statements because the Company can give no assurance that such expectations will prove to be correct. Financial outlooks are provided for the purpose of understanding the Company's financial strength and business objectives and the information may not be appropriate for other purposes. Forward looking statements or information are based on current expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company and described in the forward looking statements or information. These risks and uncertainties include but are not limited to:

- the ability of management to execute its business plan;
- the risks of the oil and gas industry, both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil, natural gas liquids and natural gas;
- risks and uncertainties involving geology of crude oil, natural gas liquids and natural gas deposits;
- risks inherent in the Company's marketing operations, including credit risk;
- the uncertainty of reserves estimates and reserves life and estimates of contingent resources and estimates of prospective resources and associated expenditures;
- the uncertainty of estimates and projections relating to production, costs and expenses;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- the Company's ability to enter into or renew leases on acceptable terms;
- fluctuations in crude oil, natural gas liquids and natural gas prices, foreign currency exchange rates and interest rates;
- health, safety and environmental risks;
- uncertainties as to the availability and cost of financing;
- the ability of the Company to add production and reserves through exploration and development activities;
- general economic and business conditions;
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- risks associated with existing and potential future law suits and regulatory actions against the Company; and
- other risks and uncertainties described elsewhere in this annual information form or in the Company's other filings with Canadian securities authorities.

The forward-looking statements or information contained in this annual information form are made as of the date hereof and the Company 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.

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

All oil and natural gas reserve information contained in this annual information form is derived from the GLJ Report and has been prepared and presented in accordance with the *Canadian Oil and Gas Evaluation Handbook* ("COGEH") and *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this annual information form. The estimated future net revenue from the production of the disclosed 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 of natural gas 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.

Contingent Resources

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

The primary contingencies which currently prevent the classification of Vermilion's contingent resource as reserves include but are not limited to:

- preparation of firm development plans, including determination of the specific scope and timing of projects;
- project sanction;
- access to capital markets;
- shareholder and regulatory approvals as applicable;
- access to required services and field development infrastructure;
- oil and natural gas prices in Canada and internationally in jurisdictions in which Vermilion operates;
- demonstration of economic viability;
- future drilling program and testing results;
- further reservoir delineation and studies;
- facility design work;
- corporate commitment;
- development timing;
- limitations to development based on adverse topography or other surface restrictions; and
- the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Vermilion will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the contingent resources described exists in the quantities predicted or estimated and that the contingent resources can be profitably produced in the future. **The net present value of the future net revenue from the contingent resources does not necessarily represent the fair market value of the contingent resources.** Actual contingent resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

Prospective Resources

“Prospective resources" are not, and should not be confused with, petroleum and natural gas reserves. "Prospective resources" are defined in COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources or that Vermilion will produce any portion of the volumes currently classified as prospective resources. The estimates of prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated and that the resources can be profitably produced in the future. **The net present value of the future net revenue from the prospective resources does not necessarily represent the fair market value of the prospective resources.** The recovery and resources estimates provided herein are estimates only. Actual prospective resources (and any volumes that may be reclassified as reserves or contingent resources) and future production from such prospective resources may be greater than or less than the estimates provided herein.

NON-GAAP MEASURES

This annual information form includes non-GAAP measures as further described herein. Management of the Company believes these non-GAAP measures are a useful tool in analyzing operating performance. These measures do not have standardized meanings prescribed by GAAP and are not disclosed in Vermilion’s audited consolidated financial statements and, therefore, may not be comparable with the calculations of similar measures for other entities.

“Cash dividends per share” represents actual cash dividends paid per share by the Company during the relevant periods.

VERMILION ENERGY INC.

General

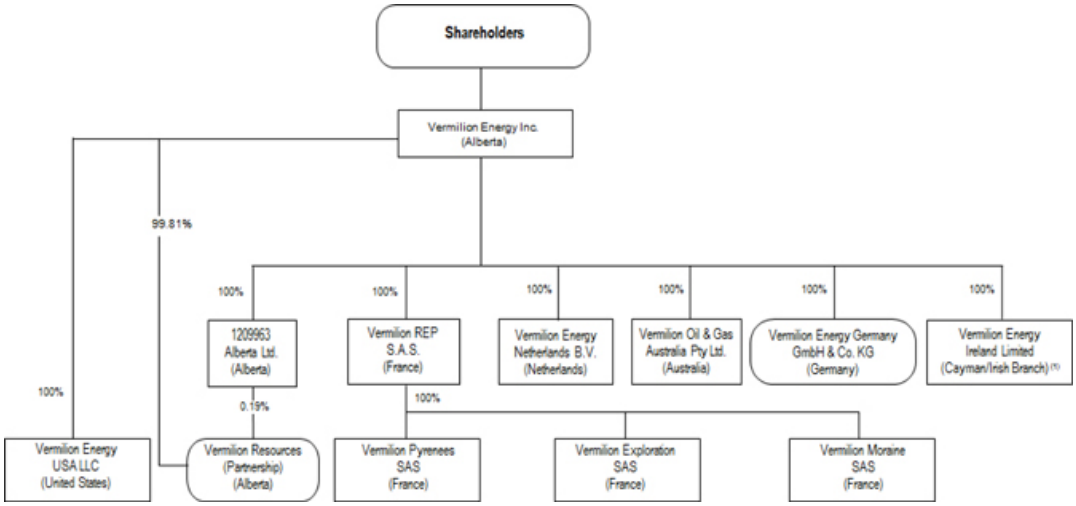
Vermilion Energy Inc. is the successor to the Trust, following the completion of the Conversion Arrangement whereby the Trust converted from an income trust to a corporate structure by way of a court approved plan of arrangement under the ABCA on September 1, 2010.

As at December 31, 2016, Vermilion had 503 full time employees of which 178 employees were located in its Calgary head office, 54 employees in its Canadian field offices, 152 employees in France, 60 employees in the Netherlands, 33 employees in Australia, 9 employees in the United States, 13 employees in Germany and 4 employees in Hungary.

Vermilion Energy Inc. was incorporated on July 21, 2010 pursuant to the provisions of the ABCA for the purpose of facilitating the Conversion Arrangement. The registered and head office of Vermilion Energy Inc. is located at Suite 3500, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3.

Organizational Structure of the Company

The following diagram shows the intercorporate relationships among the Company and each of its material subsidiaries, where each material subsidiary was incorporated or formed and the percentage of votes attaching to all voting securities of each material subsidiary beneficially owned directly or indirectly by Vermilion. Reference should be made to the appropriate sections of this annual information form for a complete description of the structure of the Company.



Note:

(1) Vermilion Energy Ireland Limited is the Irish Branch of a Cayman Islands incorporated company.

DESCRIPTION OF THE BUSINESS

Vermilion is an international energy producer that seeks to create value through the acquisition, exploration, development and optimization of producing properties in North America, Europe and Australia. Vermilion focuses on the exploitation of light oil and liquids-rich natural gas conventional resource plays in Canada and the United States, the exploration and development of high impact natural gas opportunities in the Netherlands and Germany, and oil drilling and workover programs in France and Australia. Vermilion also holds an 18.5% non-operated working interest in the Corrib gas field in Ireland.

Vermilion's priorities are health and safety, the environment, and profitability, in that order. Nothing is more important to us than the safety of the public and those who work with us, and the protection of our natural surroundings. Vermilion has been recognized as a top decile performer amongst Canadian publicly listed companies in governance practices, as a Climate "A" List performer by the CDP, and a Best Workplace in the Great Place to Work® Institute's annual rankings in Canada, France, the Netherlands and Germany. Vermilion emphasizes strategic community investment in each of our operating areas.

Operating Segments and Description of Properties[(1)]

Vermilion has operations in three core areas: North America, Europe and Australia. Vermilion's business within these regions is managed at the country level through business units which form the basis of the Company's operating segments. These operating segments, as well as a description of the material oil and natural gas properties, facilities and installations in which Vermilion has an interest, are discussed below. For a discussion of the competitive conditions affecting Vermilion's business, refer to "Competition" in the Risk Factors section of this AIF.

Canada Business Unit

Vermilion's Canadian production is primarily focused in three areas of Alberta: West Pembina, Slave Lake and Central Alberta and in the Northgate Region of southeast Saskatchewan. Vermilion's main natural gas producing areas are West Pembina and Central Alberta, while Northgate, Slave Lake and the Cardium light crude oil play in West Pembina are the main oil producing areas. West Pembina is the Company's main NGL producing area.

Vermilion holds an average 74% working interest in 445,900 (328,500 net) acres of developed land, and an average 89% working interest in 500,300 (443,000 net) acres of undeveloped land. Vermilion had 523 (358 net) producing natural gas wells and 611 (445 net) producing oil wells in Canada as at December 31, 2016.

Vermilion owns and operates three natural gas plants and has an ownership interest in seven additional plants, resulting in combined gross natural gas processing capacity of over 80 MMcf/d. In addition, Vermilion has oil processing capacity of over 25,000 bbl/d through eleven operated oil batteries including a 15,000 bbl/d oil battery in West Pembina.

For the year ended December 31, 2016, production in Canada averaged 84.3 MMcf/d of natural gas and 11,723 bbl/d of light crude oil, medium crude oil and NGLs. Sales of natural gas in 2016 were $65.9 million (2015 - $72.7 million) and sales from light crude oil, medium crude oil and NGLs were $187.0 million (2015 - $247.9 million).

During 2016, the majority of Vermilion's Canadian exploration and development expenditures were directed to our Mannville program with activity focused in the West Pembina and Ferrier areas of Alberta. During 2016 Vermilion drilled or participated in 20 (12.0 net) Mannville wells and production from the Mannville play increased by 55% as compared to 2015. Vermilion plans to drill 23 (15.0 net) Mannville wells in 2017. Vermilion expects to increase activity in its Cardium and southeast Saskatchewan plays year-over-year. The Company plans to drill or participate in nine (6.0 net) Cardium wells and 13 (11.3 net) southeast Saskatchewan wells in 2017 as compared to two (0.2 net) Cardium wells and seven (5.5 net) southeast Saskatchewan wells in 2016. Vermilion expects that the Mannville, Cardium and southeast Saskatchewan assets will continue to support the Company's production growth.

The GLJ Report assigned 77,092 Mboe of total proved reserves and 130,215 Mboe of proved plus probable reserves to Vermilion's properties located in Canada.

France Business Unit

Vermilion entered France in 1997 and has completed three subsequent acquisitions. The Company is the largest oil producer in the country and represents approximately three-quarters of domestic oil production. Vermilion predominately produces oil in France and the Company's oil is priced with reference to Dated Brent.

Vermilion's main producing areas in France are located in the Aquitaine Basin which is southwest of Bordeaux, France and in the Paris Basin, located just east of Paris. The two major fields in the Paris Basin area are Champotran and Chaunoy and the two major fields in the Aquitaine Basin are Parentis and Cazaux. Vermilion operates 20 oil batteries and 12 single well batteries in the country. Given the legacy nature of these assets, the throughput capability of these batteries exceeds any projected future requirements. Vermilion holds an average 96% working interest in 218,100 (208,900 net) acres of developed land and 100% working interest in 336,600 (336,600 net) acres of undeveloped land in the Aquitaine and Paris Basins. Vermilion had 336 (331 net) producing oil wells and three (3 net) producing gas wells in France as at December 31, 2016.

For the year ended December 31, 2016, production in France averaged 11,896 bbl/d of light crude oil and medium crude oil and 0.4 MMcf/d of natural gas. Sales from light crude oil and medium crude oil in 2016 were $246.6 million (2015 - $280.5 million) and sales of natural gas were $0.3 million (2015 - $0.9 million). Natural gas sales in France have decreased significantly since 2013 following the closure of a third party processing facility.

In 2016, Vermilion drilled four (4.0 net) wells in the Champotran field and commenced drilling a horizontal sidetrack well in the Vulaines field, with the related completion and tie-in activity planned for 2017. In 2017, Vermilion intends to drill its first four (4.0 net) wells in the Neocomian fields in the Paris Basin. The Company also intends to continue its ongoing program of workovers and optimizations. By continuing to develop its inventory in France, while minimizing declines through workovers and optimizations, Vermilion seeks to deliver moderate production growth from its French assets.

The GLJ Report assigned 42,958 Mboe of total proved reserves and 65,040 Mboe of proved plus probable reserves to Vermilion's properties located in France.

Netherlands Business Unit

Vermilion entered the Netherlands in 2004 and is the country's second largest onshore natural gas producer. Vermilion's natural gas production in the Netherlands is priced off of the TTF index.

Vermilion's Netherlands assets consist of 24 onshore concessions and two offshore concessions. Production consists solely of natural gas with a small amount of related condensate. Vermilion's total land position in the Netherlands covers 1,492,500 (841,500 net) acres at an average 56% working interest, of which 95% is undeveloped. Vermilion had 54 (37 net) producing natural gas wells as at December 31, 2016.

For the year ended December 31, 2016, Vermilion's production in the Netherlands averaged 47.8 MMcf/d of natural gas and 88 bbl/d of NGLs. Sales in 2016 of natural gas were $99.3 million (2015 - $127.3 million) and sales from NGLs were $1.4 million (2015 - $1.8 million).

Vermilion drilled two (0.9 net) wells in the Netherlands during 2016 and the Company expects to drill two (1.0 net) exploration wells in 2017. In addition, Vermilion expects to complete a seismic program in the Akkrum concession and execute a major turnaround at the Garijp Treatment Centre. Vermilion expects that its inventory of potentially high-impact exploration and development opportunities in the Netherlands will continue to support the Company's production growth in the country.

The GLJ Report assigned 10,473 Mboe of total proved reserves and 17,733 Mboe of proved plus probable reserves to Vermilion's properties located in the Netherlands.

Germany Business Unit

Vermilion entered Germany in 2014 with the acquisition of a 25% non-operated interest in natural gas producing assets. In December 2016, Vermilion completed an acquisition of oil and gas producing properties that provided Vermilion with its first operated position in the country. Vermilion holds a significant undeveloped land position in Germany as a result of a farm-in agreement the Company entered into in 2015. Vermilion's natural gas production in Germany is priced with reference to TTF and oil production is priced with reference to Dated Brent.

Including the interests that were acquired in December 2016, Vermilion's producing assets in Germany consist of operated and non-operated interests in seven natural gas fields and five oil fields. Prior to the December 2016 acquisition, Vermilion's producing assets in Germany consisted of a 25% non-operated interest in four natural gas fields. Including the wells from this acquisition, Vermilion had 141 (111 net) producing oil wells and 20 (7 net) producing natural gas wells as at December 31, 2016.

Vermilion holds a significant land position in northwest Germany comprised of 67,600 (25,800 net) developed acres and 2,609,300 (1,054,900 net) undeveloped acres. The Company also holds a 0.4% equity interest in Erdgas Munster GmbH ("EGM"), a joint venture created in 1959 to jointly transport, process, and market gas in northwest Germany. This transportation interest allows for our proportionate share of produced volumes to be processed, blended, and transported to designated gas consumers through the EGM network of approximately 2,000 kilometres of pipeline.

For the year ended December 31, 2016, production in Germany averaged 14.9 MMcf/d of natural gas. Sales of natural gas in 2016 were $29.0 million (2015 - $41.4 million).

During 2016, Vermilion continued its ongoing analysis of the proprietary geologic data associated with the farm-in assets. In 2017, the Company plans to invest in optimization and other well work on the assets the Company acquired in December 2016 as well as prepare for the drilling of one (0.25 net) well in the Dümmersee-Uchte area which is expected to be drilled in 2018.

The GLJ Report assigned 12,202 Mboe of total proved reserves and 23,528 Mboe of proved plus probable reserves to Vermilion's properties located in Germany.

Ireland Business Unit

Vermilion acquired an 18.5% non-operating interest in the offshore Corrib gas field located off the northwest coast of Ireland in 2009. The asset is comprised of six offshore wells, an onshore natural gas processing facility and offshore and onshore pipeline segments. At the time of the acquisition most of the key components of the project, with the exception of the onshore pipeline, were either complete or in the latter stages of development. In 2011, approvals and permissions were granted for the onshore gas pipeline and tunneling commenced in December 2012. In May 2014, Vermilion announced the completion of tunnel boring operations. In September 2015, the project operator, Shell E&P Ireland Limited, declared the project operationally ready for service. With the final regulatory consent received on December 29, 2015, gas began to flow from the Corrib project on December 30, 2015.

Production volumes at Corrib reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d) net to Vermilion at the end of Q2 2016 following recertification activities associated with a third party gas distribution pipeline network. Production at Corrib is expected to remain stable for a period of 12 - 18 months following the achievement of peak production volumes before starting to decline.

For the year ended December 31, 2016, production in Ireland averaged 50.9 MMcf/d of natural gas. Sales of natural gas in 2016 were $109.2 million. There were negligible sales in 2015 as production did not commence until December 30, 2015.

The GLJ Report assigned 16,596 Mboe of total proved reserves and 25,061 Mboe of proved plus probable reserves to Vermilion's property located in Ireland.

Australia Business Unit

In 2005, Vermilion acquired a 60% operated interest in the Wandoo offshore oil field and related production assets, located on Western Australia's northwest shelf. In 2007, Vermilion acquired the remaining 40% interest in the asset. Production occurs from 18 well bores and five lateral sidetrack wells that are tied into two platforms, Wandoo 'A' and Wandoo 'B'. Wandoo 'B' is permanently manned, houses the required production facilities and incorporates 400,000 bbls of oil storage within the platform's concrete gravity structure. The Wandoo 'B' facilities are capable of processing 162,000 bbl/d of total fluid to separate the oil from produced water. Vermilion's land position in the Wandoo field is comprised of 59,600 acres (gross and net).

For the year ended December 31, 2016, Vermilion's production in Australia averaged 6,304 bbl/d of light crude oil and medium crude oil. Sales in 2016 from light crude oil and medium crude oil were $136.8 million (2015 - $162.8 million).

During 2015 and 2016, Vermilion drilled three wells in Australia and does not presently expect to drill any additional Australian wells until 2019. Vermilion manages its Australian asset and related capital investment programs to maintain stable production at levels of between 6,000 – 8,000 boe/d.

The GLJ Report assigned 12,418 Mboe of total proved reserves and 17,068 Mboe of proved plus probable reserves to Vermilion's property located in Australia.

United States Business Unit

Vermilion entered the United States in 2014. The Company's assets include 108,500 (97,200 net) acres of land in the Powder River basin of northeastern Wyoming, of which 96% is undeveloped. Vermilion had 11 (9 net) producing oil wells in the United States as at December 31, 2016.

For the year ended December 31, 2016, Vermilion’s production in the United States averaged 422 bbl/d of light crude oil, medium crude oil and NGLs and 0.2 MMcf/d of natural gas. Sales from all commodities in 2016 were $7.3 million (2015 - $4.3 million).

During 2016, Vermilion continued work on its early stage Turner Sand development in the Powder River Basin, completing two (2.0 net) wells that were drilled in 2015 and drilling one (1.0 net) additional well in 2016. In 2017, Vermilion expects to drill three (3.0 net) wells in this play.

The GLJ Report assigned 4,076 Mboe of total proved reserves and 11,477 Mboe of proved plus probable reserves to Vermilion's properties located in the United States.

Central and Eastern Europe (CEE) Business Unit

Vermilion has established a CEE Business unit with a head office in Budapest, Hungary. The CEE business unit is responsible for business development in the CEE, including managing the exploration and development opportunities associated with the Company's land holdings in Hungary, Croatia and Slovakia.

At present, the CEE business unit does not have any production or revenues.

Vermilion's land position in the CEE consists of 322,100 (322,100 net) acres in Hungary, 183,000 (91,500 net) acres in Slovakia and 2.35 million (2.35 million net) acres in Croatia. Currently, Vermilion's entire land position in the CEE is undeveloped.

(1) The production numbers stated refer to Vermilion's working interest share before deduction of Crown, freehold and other royalties. Reserve amounts are gross reserves, stated before deduction of royalties, as at December 31, 2016, based on forecast costs and price assumptions as evaluated in the GLJ Report.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History and Outlook

The following describes the development of Vermilion's business over the last three completed financial years. None of the acquisitions described below constituted a "significant acquisition" within the meaning of applicable securities laws.

2014

Vermilion achieved record annual production of 49,573 boe/d exceeding the top end of guidance targets following three upward revisions to guidance during the year. Average annual production increased by 21% as compared to 2013. Canadian production growth was attributable to a 20% increase in average production from the Cardium light oil resource play, a near tripling of Mannville condensate-rich gas production and the addition of approximately 1,900 boe/d of production from southeast Saskatchewan assets that the Company acquired during the year. In addition, full year production growth of 8% in the Netherlands and the addition of approximately 2,500 boe/d associated with German assets Vermilion acquired during the year contributed to the increase.

As announced in 2013, Vermilion increased its monthly dividend by 7.5% to $0.215 per share commencing with the January 2014 dividend. Vermilion maintained its monthly dividend at $0.215 per share throughout 2014.

New Area Entries

During 2014, Vermilion successfully entered four new areas within the Company's existing core regions following acquisitions in Germany, Southeast Saskatchewan, and the United States as well as the receipt of a significant concession in Hungary.

In February 2014, Vermilion acquired a 25% non-operated interest in a four-partner consortium in Germany from GDF Suez S.A. (currently known as Engie E&P Deutschland GmbH). The assets comprised four gas producing fields across eleven production licenses characterized by a low effective annual decline rate of approximately 11%. The acquired assets included both exploration and production licenses comprising a total of 204,000 gross acres, of which 85% was in the exploration license. The acquisition represented Vermilion's entry into Germany, a producing region with a long history of oil and gas development activity, low political risk, and strong marketing fundamentals. Total consideration for the acquisition was $172.9 million which was funded through existing credit facilities.

In April 2014, Vermilion completed the acquisition of Elkhorn Resources Inc., a private southeast Saskatchewan producer. The acquisition provided Vermilion with light crude oil producing assets located in the Northgate region of southeast Saskatchewan, approximately 57,000 net acres of land (approximately 80% undeveloped), seven oil batteries, and preferential access to 50% or greater capacity at a solution gas facility. Total consideration comprised $180 million of cash, the assumption of approximately $43 million of debt, and the issuance of 2.8 million common shares of Vermilion valued at approximately $205 million (based on the closing price per Vermilion common share of $72.50 on the Toronto Stock Exchange on April 29, 2014).

In September 2014, Vermilion acquired assets in the Powder River Basin of northeastern Wyoming for $11.1 million. The acquired assets included approximately 68,000 acres of land (98% undeveloped) and working interest production of approximately 200 bbls/d (100% light crude oil and medium crude oil). The land base included 53,000 net acres at an average operated working interest of 70% in a tight oil project in the Turner Sand at a depth of approximately 1,500 metres. The acquisition provided Vermilion with a low-cost entry into the Powder River Basin and an entry into the sizable United States exploration and production market. The Company established an office in Denver, Colorado for its new United States business unit.

In 2014, Vermilion was awarded the Battonya South concession in Hungary. The concession consists of 116,000 gross acres located in the southern part of the country. The term of the exploration license is 4 years.

Crude Oil Price Decline

Beginning in mid-2014, global crude oil prices began a significant decline markedly changing the upstream energy environment. Vermilion took a number of actions in response to the price environment.

In November 2014, Vermilion re-launched its company-wide Profitability Enhancement Program ("PEP") which is focused on enhancing long-term profitability. This represented the third installment of PEP since the Company's inception with the prior two initiatives having achieved strong results in both the 1998 industry downturn and the financial crisis of 2008-2009. PEP focuses Vermilion's employees and contractors on increasing revenues, and reducing capital, operating and general and administrative costs, as well as improving efficiencies where possible.

To preserve financial flexibility by providing ongoing access to a modest amount of very low-cost equity capital, Vermilion amended its existing Dividend Reinvestment Plan to include a Premium Dividend™ Component. Under the Premium Dividend™ Component, shares are issued at a 3.5% discount to a calculated average market price. The shares are sold at prevailing market prices by the Plan Broker (Canaccord Genuity Corporation), who provides participating Shareholders with a premium cash payment equal to 101.5% of their dividends, while the Plan Broker retains the balance of the discount as its fee.

In December 2014, Vermilion announced a reduced capital program for 2015 to support the strength of its balance sheet and the sustainability of its dividend.

Other Events

The Corrib project in Ireland continued to progress following the completion of tunnel boring operations in May 2014. During the remainder of 2014, project operator Shell Exploration & Production Ireland Ltd. successfully completed offshore workover and pipeline operations and outfitted the 4.9 km tunnel, including installation of flow and umbilical lines, hydro-testing and dewatering, with the final weld completed in December 2014.

In 2014, Vermilion celebrated its 20 year anniversary as a publicly traded company.

2015

Vermilion achieved record annual production of 54,922 boe/d representing an increase of 11% as compared to 2014. Full-year average production was within 0.1% of guidance as strong production results from other business units largely offset the production shortfall related to regulatory delays at Corrib.

In 2015, Vermilion entered into a farm-in agreement in northwest Germany. The farm-in provided Vermilion with participating interest in 18 onshore exploration licenses, comprising approximately 850,000 net undeveloped acres in the North German Basin, in exchange for carrying 50% of the farmor's costs associated with the drilling and testing of six net exploration wells over the following five years. The agreement also granted Vermilion operatorship during the exploration phase for 11 of the 18 licenses as well as proportionate ownership of key proprietary data spanning the farm-in assets.

On December 29, 2015 Vermilion announced that Shell E&P Ireland Limited, operator of the Corrib project, received the final remaining consent required for production from the office of Ireland's Minister for Communications, Energy and Natural Resources. Following this, natural gas began to flow from the Corrib gas project in Ireland on December 30, 2015.

Vermilion continued to prioritize preserving the strength of its balance sheet and increase its financial flexibility in response to the continued weak commodity price environment. Total exploration and development ("E&D") investment for 2015 totalled $487 million, representing a nearly 30% decrease from the prior year. Vermilion continued to focus on reducing costs through PEP and the Company increased its credit facility capacity by $500 million during the year to $2.0 billion while also extending the term to May 2019.

2016

Vermilion achieved record annual production of 63,526 boe/d representing an increase of 16% as compared to 2015. The increase was attributable to a full-year of Corrib production and organic growth in the Netherlands.

The commodity price environment continued to be extremely challenging during 2016. WTI averaged US$43.32/bbl for the year and reached an intra-year, monthly average low of US$30.62/bbl in February 2016. To support its balance sheet and dividend in the prevailing price environment, the Company continued to focus on further improving capital efficiencies as well as achieving cost reductions through PEP. Accordingly, in January 2016, Vermilion announced a $285 million E&D capital budget for 2016 representing a 42% decrease from 2015. As commodity prices continued to weaken during Q1 2016, in February 2016 Vermilion announced a further reduction in its 2016 E&D capital budget to $235 million. In August 2016, Vermilion modestly increased its E&D capital expenditure guidance for 2016 to $240 million. E&D capital expenditures for 2016 totalled $242.4 million, representing decreases from 2015 and 2014 of 50% and 65%, respectively.

Vermilion maintained its dividend at $0.215 per month during the year. Commencing with the October 2016 dividend payment, the Company began prorating the Premium Dividend™ Component of the Dividend Reinvestment Plan by 25%. This resulted from the continued strength in the Company's business associated with cost reductions and capital efficiency improvements coupled with the expectation of a more stable commodity price environment. Vermilion subsequently increased the proration factor applied to the Premium Dividend™ Component to 50% commencing with the January 2017 dividend payment. In February 2017, the Company announced a further increase in the proration factor to 75% commencing with the April 2017 dividend payment. Subject to unexpected changes in the commodity price outlook, Vermilion intends to discontinue the Premium Dividend™ Component beginning with the July 2017 dividend payment, such that there would be no further equity issuance under this program.

Vermilion repaid the $225 million of 6.5% Senior Unsecured Notes that came due on February 10, 2016 with funds from its credit facility. While the Company assessed opportunities to diversify its debt structure, the credit facility represented the company's most cost-effective method of borrowing.

Effective March 1, 2016, Mr. Lorenzo Donadeo retired as Chief Executive Officer of Vermilion and became Chair of the Board of Directors. Mr. Anthony Marino, previously the Company's President and Chief Operating Officer, assumed the role of President and CEO. Mr. Larry Macdonald, previously the Board of Director's Chair, assumed the role of the newly created role of Lead Independent Director.

In December 2016, Vermilion closed an acquisition of producing oil and gas properties in Germany from Engie E&P Deutschland GmbH (previously known as GDF Suez S.A.) for total consideration of $45.6 million, net of acquired product inventory. The Acquisition comprised operated and non-operated interests in five oil and three natural gas producing fields, along with an operated interest in one exploration license. Vermilion assumed operatorship of six of the eight producing fields, with the other fields operated by ExxonMobil Production Deutschland (EMPG) and Deutsche Erdoel AG (DEA). Production from the acquired assets was approximately 2,000 boe/d in 2016. The acquisition provided Vermilion with its first operated producing properties in Germany, and advanced the Company's objective of developing a material business unit in the country.

In June 2016, the Republic of Croatia ratified the grant of four exploration blocks to Vermilion. The exploration blocks consisted of approximately 2.35 million gross acres (100% working interest), with a substantial portion of the acreage located near existing crude oil and natural gas fields in northeast Croatia. The initial five-year exploration period consists of two phases with an option to relinquish the blocks following the initial three-year phase. In December 2016, Vermilion entered into a farm-in agreement in Slovakia with NAFTA, Slovakia's dominant exploration and production company. The farm-in agreement grants Vermilion a 50% working interest to jointly explore 183,000 gross acres on an existing license. The primary term of the farm-in agreement is five years.

Vermilion was awarded a position on CDP's 2016 Climate "A" List. CDP (formerly Carbon Disclosure Project) is a London-based not-for-profit organization that administers a global environmental disclosure system that assists in the measurement and management of corporate environmental impacts. Only 193 companies globally achieved Climate "A" List recognition in 2016 and Vermilion was one of only five oil and gas companies in the world, and the only North American energy company, on the 2016 Climate "A" List. Vermilion has voluntarily reported emissions data to CDP for each year since 2012, recognizing the importance of measuring and understanding the Company's environmental impact.

Outlook

While commodity prices have increased from the lows experienced during 2016, significant uncertainty in the commodity price environment remains. Vermilion intends to maintain a low level of financial leverage and keep cash uses for dividends and E&D capital investment below internal cash generation. Consistent with these objectives, in October 2016 Vermilion announced an E&D capital budget for 2017 of $295 million with corresponding production guidance of between 69,000-70,000 boe/d. Based on the current commodity price strip, Vermilion expects to fully fund 2017 E&D capital investment and cash dividends from fund flows from operations, with surplus cash generation primarily directed to debt reduction.

TM denotes trademark of Canaccord Genuity Capital Corporation.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Reserves and Future Net Revenue

The following is a summary of the oil and natural gas reserves and the value of future net revenue of Vermilion as evaluated by GLJ in a report dated February 1, 2016 with an effective date of December 31, 2016. Pricing used in the forecast price evaluations is set forth in the notes to the tables.

Reserves and other oil and gas information contained in this section is effective December 31, 2016 unless otherwise stated.

All evaluations of future net revenue set forth in the tables below are stated after overriding and lessor royalties, Crown royalties, freehold royalties, mineral taxes, direct lifting costs, normal allocated overhead and future capital investments, including abandonment and reclamation obligations. **Future net revenues estimated by the GLJ Report do not represent the fair market value of the reserves. Other assumptions relating to the costs, prices for future production and other matters are included in the GLJ Report. There is no assurance that the future price and cost assumptions used in the GLJ Report will prove accurate and variances could be material.**

Reserves for Australia, Canada, France, Germany, Ireland, the Netherlands and United States are established using deterministic methodology. Total proved reserves are established at the 90 percent probability (P90) level. There is a 90 percent probability that the actual reserves recovered will be equal to or greater than the P90 reserves. Total proved plus probable reserves are established at the 50 percent probability (P50) level. There is a 50 percent probability that the actual reserves recovered will be equal to or greater than the P50 reserves.

The Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are contained in Schedules "A" and "B", respectively.

The following tables provide reserves data and a breakdown of future net revenue by component and product type using forecast prices and costs. For Canada, the tables following include AGCA.

The following tables may not total due to rounding.

Oil and Gas Reserves - Based on Forecast Prices and Costs [1]

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Developed Producing [3] [5] [6]								
Australia	10,718	10,718	-	-	-	-	-	-
Canada	12,277	10,990	-	-	12	8	112,918	101,728
France	36,481	33,478	-	-	-	-	5,412	5,024
Germany	4,805	4,706	-	-	-	-	30,892	27,510
Ireland	-	-	-	-	-	-	95,861	95,861
Netherlands	-	-	-	-	-	-	41,494	29,860
United States	699	551	-	-	-	-	696	552
Total Proved Developed Producing	64,980	60,443	-	-	12	8	287,273	260,535

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Developed Producing [3] [5] [6]								
Australia	-	-	-	-	-	-	10,718	10,718
Canada	1,371	1,291	2,482	2,275	8,484	6,395	40,235	34,942
France	-	-	-	-	-	-	37,383	34,315
Germany	-	-	-	-	-	-	9,954	9,291
Ireland	-	-	-	-	-	-	15,977	15,977
Netherlands	-	-	-	-	59	59	6,975	5,036
United States	-	-	-	-	97	76	912	719
	1,371	1,291	2,482	2,275	8,640	6,530	122,154	110,998

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Developed Non-Producing								
Australia	700	700	-	-	-	-	-	-
Canada	1,008	874	-	-	-	-	24,705	22,319
France	1,814	1,666	-	-	-	-	-	-
Germany	240	230	-	-	-	-	8,227	7,389
Ireland	-	-	-	-	-	-	-	-
Netherlands	-	-	-	-	-	-	17,815	15,327
United States	-	-	-	-	-	-	-	-
Total Proved Developed Non-Producing	3,762	3,470	-	-	-	-	50,747	45,035

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Developed Non-Producing								
Australia	-	-	-	-	-	-	700	700
Canada	-	-	2,536	2,389	1,649	1,283	7,197	6,275
France	-	-	-	-	-	-	1,814	1,666
Germany	-	-	-	-	-	-	1,611	1,462
Ireland	-	-	-	-	-	-	-	-
Netherlands	-	-	-	-	21	21	2,990	2,576
United States	-	-	-	-	-	-	-	-
Total Proved Developed Non-Producing	-	-	2,536	2,389	1,670	1,304	14,312	12,679

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Undeveloped [3] [8]								
Australia	1,000	1,000	-	-	-	-	-	-
Canada	8,677	7,595	-	-	-	-	79,475	71,420
France	3,749	3,506	-	-	-	-	70	70
Germany	243	237	-	-	-	-	2,361	1,918
Ireland	-	-	-	-	-	-	3,714	3,714
Netherlands	-	-	-	-	-	-	3,041	3,041
United States	2,470	2,019	-	-	-	-	2,273	1,858
Total Proved Undeveloped	16,139	14,357	-	-	-	-	90,934	82,021

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Undeveloped								
Australia	-	-	-	-	-	-	1,000	1,000
Canada	-	-	3,043	2,812	7,230	5,541	29,660	25,508
France	-	-	-	-	-	-	3,761	3,518
Germany	-	-	-	-	-	-	637	557
Ireland	-	-	-	-	-	-	619	619
Netherlands	-	-	-	-	1	1	508	508
United States	-	-	-	-	315	258	3,164	2,587
Total Proved Undeveloped	-	-	3,043	2,812	7,546	5,800	39,349	34,297

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved [3]								
Australia	12,418	12,418	-	-	-	-	-	-
Canada	21,962	19,460	-	-	12	8	217,098	195,467
France	42,044	38,650	-	-	-	-	5,482	5,094
Germany	5,288	5,173	-	-	-	-	41,480	36,817
Ireland	-	-	-	-	-	-	99,575	99,575
Netherlands	-	-	-	-	-	-	62,350	48,228
United States	3,169	2,570	-	-	-	-	2,969	2,410
Total Proved	84,881	78,271	-	-	12	8	428,954	387,591

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved								
Australia	-	-	-	-	-	-	12,418	12,418
Canada	1,371	1,291	8,061	7,476	17,363	13,219	77,092	66,725
France	-	-	-	-	-	-	42,958	39,499
Germany	-	-	-	-	-	-	12,202	11,310
Ireland	-	-	-	-	-	-	16,596	16,596
Netherlands	-	-	-	-	81	81	10,473	8,120
United States	-	-	-	-	412	334	4,076	3,306
Total Proved	1,371	1,291	8,061	7,476	17,856	13,634	175,815	157,974

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Probable [4]								
Australia	4,650	4,650	-	-	-	-	-	-
Canada	14,103	12,146	-	-	2	1	151,707	135,215
France	21,933	20,261	-	-	-	-	892	884
Germany	2,279	2,238	-	-	-	-	54,284	47,482
Ireland	-	-	-	-	-	-	50,787	50,787
Netherlands	-	-	-	-	-	-	43,184	33,118
United States	5,727	4,716	-	-	-	-	5,481	4,512
Total Probable	48,692	44,011	-	-	2	1	306,335	271,998

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Probable								
Australia	-	-	-	-	-	-	4,650	4,650
Canada	284	267	4,677	4,395	12,907	9,730	53,123	45,190
France	-	-	-	-	-	-	22,082	20,408
Germany	-	-	-	-	-	-	11,326	10,152
Ireland	-	-	-	-	-	-	8,465	8,465
Netherlands	-	-	-	-	63	56	7,260	5,576
United States	-	-	-	-	760	625	7,401	6,093
Total Probable	284	267	4,677	4,395	13,730	10,411	114,307	100,534

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Plus Probable [3] [4]								
Australia	17,068	17,068	-	-	-	-	-	-
Canada	36,065	31,606	-	-	14	9	368,805	330,682
France	63,977	58,911	-	-	-	-	6,374	5,978
Germany	7,567	7,411	-	-	-	-	95,764	84,299
Ireland	-	-	-	-	-	-	150,362	150,362
Netherlands	-	-	-	-	-	-	105,534	81,346
United States	8,896	7,286	-	-	-	-	8,450	6,922
Total Proved Plus Probable	133,573	122,282	-	-	14	9	735,289	659,589

	Shale Gas		Coal Bed Methane		Natural Gas Liquids			BOE
	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (MMcf)	Net [2] (MMcf)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Plus Probable [3] [4]								
Australia	-	-	-	-	-	-	17,068	17,068
Canada	1,655	1,558	12,738	11,871	30,270	22,949	130,215	111,915
France	-	-	-	-	-	-	65,040	59,907
Germany	-	-	-	-	-	-	23,528	21,462
Ireland	-	-	-	-	-	-	25,061	25,061
Netherlands	-	-	-	-	144	137	17,733	13,696
United States	-	-	-	-	1,172	959	11,477	9,399
Total Proved Plus Probable	1,655	1,558	12,738	11,871	31,586	24,045	290,122	258,508

Notes:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. See “Forecast Prices used in Estimates”. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(2) "Gross Reserves" are Vermilion's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Vermilion. "Net Reserves" are Vermilion's working interest (operating or non-operating) share after deduction of royalty obligations, plus Vermilion's royalty interests in reserves.

(3) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(4) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(5) "Developed" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

(6) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(7) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(8) "Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

Net Present Value of Future Net Revenue - Based on Forecast Prices and Costs **(1)**

	Before Deducting Future Income Taxes Discounted At					After Deducting Future Income Taxes Discounted At				
(M$)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Developed Producing (2) (4) (5)										
Australia	134,236	217,117	240,607	240,546	231,618	164,830	197,187	199,187	190,432	178,594
Canada	963,690	777,268	645,191	553,740	487,804	963,690	777,268	645,191	553,740	487,804
France	2,009,158	1,404,527	1,073,623	871,502	736,836	1,664,358	1,169,631	894,523	725,047	611,642
Germany	193,385	187,330	161,141	138,822	121,707	193,385	187,330	161,141	138,822	121,707
Ireland	471,720	441,671	396,917	356,653	323,302	471,720	441,671	396,917	356,653	323,302
Netherlands	76,272	86,832	91,069	92,068	91,365	65,732	76,545	81,019	82,239	81,743
United States	29,716	23,345	19,334	16,637	14,710	29,716	23,345	19,334	16,637	14,710
Total Proved Developed Producing	3,878,177	3,138,090	2,627,882	2,269,968	2,007,342	3,553,431	2,872,977	2,397,312	2,063,570	1,819,502
Proved Developed Non-Producing (2) (4) (6)										
Australia	31,411	35,177	32,247	28,181	24,473	31,411	35,177	32,247	28,181	24,473
Canada	147,607	108,964	87,413	73,769	64,329	147,607	108,964	87,413	73,769	64,329
France	87,674	71,387	60,449	52,665	46,857	60,567	49,131	41,376	35,850	31,732
Germany	41,121	29,470	21,864	16,769	13,244	41,121	29,470	21,864	16,769	13,244
Ireland	-	-	-	-	-	-	-	-	-	-
Netherlands	46,907	45,115	42,066	38,740	35,545	33,688	32,489	29,973	27,127	24,367
United States	-	-	-	-	-	-	-	-	-	-
Total Proved Developed Non-Producing	354,720	290,113	244,039	210,124	184,448	314,394	255,231	212,873	181,696	158,145
Proved Undeveloped (2) (7)										
Australia	34,323	24,134	16,832	11,574	7,761	12,618	2,648	(1,772)	(3,929)	(5,057)
Canada	569,308	368,599	249,906	175,120	125,532	416,577	282,567	199,226	144,148	106,013
France	187,253	137,261	104,175	81,348	64,957	129,800	91,741	66,604	49,467	37,335
Germany	18,403	11,756	7,584	4,902	3,130	18,403	11,756	7,584	4,902	3,130
Ireland	12,873	9,337	6,763	4,894	3,536	12,873	9,337	6,763	4,894	3,536
Netherlands	10,896	9,095	7,611	6,411	5,443	8,160	6,584	5,294	4,263	3,443
United States	72,284	38,191	20,027	9,645	3,348	72,284	38,191	20,027	9,645	3,348
Total Proved Undeveloped	905,340	598,373	412,898	293,894	213,707	670,715	442,824	303,726	213,390	151,748
Proved (2)										
Australia	199,970	276,428	289,686	280,301	263,852	208,859	235,012	229,662	214,684	198,010
Canada	1,680,605	1,254,831	982,510	802,629	677,665	1,527,874	1,168,799	931,830	771,657	658,146
France	2,284,085	1,613,175	1,238,247	1,005,515	848,650	1,854,725	1,310,503	1,002,503	810,364	680,709
Germany	252,909	228,556	190,589	160,493	138,081	252,909	228,556	190,589	160,493	138,081
Ireland	484,593	451,008	403,680	361,547	326,838	484,593	451,008	403,680	361,547	326,838
Netherlands	134,075	141,042	140,746	137,219	132,353	107,580	115,618	116,286	113,629	109,553
United States	102,000	61,536	39,361	26,282	18,058	102,000	61,536	39,361	26,282	18,058
Total Proved	5,138,237	4,026,576	3,284,819	2,773,986	2,405,497	4,538,540	3,571,032	2,913,911	2,458,656	2,129,395
Probable (3)										
Australia	198,227	163,180	128,734	101,649	81,484	107,201	87,874	68,562	53,406	42,201
Canada	1,372,807	814,946	539,761	384,694	288,798	1,009,708	591,846	389,432	277,104	208,604
France	1,378,689	734,502	464,026	323,290	239,221	974,931	502,379	305,000	203,471	143,693
Germany	336,322	208,119	130,651	86,473	59,902	248,590	162,713	105,566	71,859	51,003
Ireland	354,566	235,805	167,862	126,297	99,303	354,566	235,805	167,862	126,297	99,303
Netherlands	162,029	137,048	115,870	98,750	85,096	111,908	92,487	75,843	62,469	51,946
United States	270,229	147,720	90,240	59,467	41,247	175,706	98,838	61,958	41,765	29,522
Total Probable	4,072,869	2,441,320	1,637,144	1,180,620	895,051	2,982,610	1,771,942	1,174,223	836,371	626,272
Proved Plus Probable (2) (3)										
Australia	398,197	439,608	418,420	381,950	345,336	316,060	322,886	298,224	268,090	240,211
Canada	3,053,412	2,069,777	1,522,271	1,187,323	966,463	2,537,582	1,760,645	1,321,262	1,048,761	866,750
France	3,662,774	2,347,677	1,702,273	1,328,805	1,087,871	2,829,656	1,812,882	1,307,503	1,013,835	824,402
Germany	589,231	436,675	321,240	246,966	197,983	501,499	391,269	296,155	232,352	189,084
Ireland	839,159	686,813	571,542	487,844	426,141	839,159	686,813	571,542	487,844	426,141
Netherlands	296,104	278,090	256,616	235,969	217,449	219,488	208,105	192,129	176,098	161,499
United States	372,229	209,256	129,601	85,749	59,305	277,706	160,374	101,319	68,047	47,580
Total Proved Plus Probable	9,211,106	6,467,896	4,921,963	3,954,606	3,300,548	7,521,150	5,342,974	4,088,134	3,295,027	2,755,667

Notes:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. See “Forecast Prices used in Estimates”. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(4) "Developed" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production.

(5) "Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
(6) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
(7) "Undeveloped" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

Total Future Net Revenue (Undiscounted) Based on Forecast Prices and Costs **(1)**

(M$)	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
Proved **(2)**								
Australia	1,130,774	-	585,013	98,280	247,512	199,969	(8,890)	208,859
Canada	3,767,788	508,170	1,060,685	421,548	96,780	1,680,605	152,731	1,527,874
France	3,892,917	309,696	1,017,941	123,472	157,722	2,284,086	429,361	1,854,725
Germany	812,577	43,400	383,854	12,267	120,147	252,909	-	252,909
Ireland	755,793	-	174,058	35,412	61,729	484,594	-	484,594
Netherlands	523,311	103,758	197,686	22,639	65,154	134,074	26,495	107,579
United States	297,606	83,116	48,860	60,639	2,991	102,000	-	102,000
Total Proved	11,180,766	1,048,140	3,468,097	774,257	752,035	5,138,237	599,697	4,538,540
Proved Plus Probable **(2) (3)**								
Australia	1,611,584	-	777,207	175,660	260,522	398,197	82,137	316,060
Canada	6,601,327	949,111	1,699,340	774,361	125,102	3,053,413	515,831	2,537,582
France	6,232,560	486,688	1,560,331	317,562	205,205	3,662,774	833,118	2,829,656
Germany	1,534,267	102,937	592,967	88,681	160,451	589,231	87,732	501,499
Ireland	1,208,966	-	272,665	35,412	61,729	839,159	-	839,159
Netherlands	887,526	181,892	286,933	45,647	76,950	296,104	76,616	219,488
United States	888,444	241,131	130,837	137,814	6,434	372,229	94,523	277,706
Total Proved Plus Probable	18,964,674	1,961,759	5,320,280	1,575,137	896,393	9,211,107	1,689,957	7,521,150

Notes:
(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. See “Forecast Prices used in Estimates”. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.
(2) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
(3) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Future Net Revenue by Product Type Based on Forecast Prices and Costs [(1)]

	Future Net Revenue Before Income Taxes [(2)] (Discounted at 10% Per Year)	Unit Value
Proved Developed Producing	**(M$)**	**($/boe)**
Light crude oil & medium crude oil [(3)]	1,869,323	28.43
Heavy Oil [(3)]	-	-
Conventional Natural gas [(4)]	755,799	16.95
Shale Gas	1,928	6.93
Coal Bed Methane	832	2.19
Total Proved Developed Producing	2,627,882	23.68
Proved Developed Non-Producing		
Light crude oil & medium crude oil [(3)]	119,652	32.00
Heavy Oil [(3)]	-	-
Conventional Natural gas [(4)]	123,922	14.51
Shale Gas	-	-
Coal Bed Methane	465	1.17
Total Proved Developed Non-Producing	244,039	19.25
Proved Undeveloped		
Light crude oil & medium crude oil [(3)]	279,927	14.84
Heavy Oil [(3)]	-	-
Conventional Natural gas [(4)]	132,343	8.84
Shale Gas	-	-
Coal Bed Methane	628	1.34
Total Proved Undeveloped	412,898	12.04
Proved		
Light crude oil & medium crude oil [(3)]	2,268,902	25.72
Heavy Oil [(3)]	-	-
Conventional Natural gas [(4)]	1,012,064	14.82
Shale Gas	1,928	6.97
Coal Bed Methane	1,925	1.53
Total Proved	3,284,819	20.79
Probable		
Light crude oil & medium crude oil [(3)]	1,044,229	20.31
Heavy Oil [(3)]	-	-
Conventional Natural gas [(4)]	590,638	12.22
Shale Gas	357	6.26
Coal Bed Methane	1,920	2.62
Total Probable	1,637,144	16.28
Proved Plus Probable		
Light crude oil & medium crude oil [(3)]	3,313,131	23.76
Heavy Oil [(3)]	-	-
Conventional Natural gas [(4)]	1,602,702	13.70
Shale Gas	2,285	6.93
Coal Bed Methane	3,845	1.91
Total Proved Plus Probable	4,921,963	19.04

Notes:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. See “Forecast Prices used in Estimates”. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(2) Other Company revenue and costs not related to a specific product type have been allocated proportionately to the specified product types. Unit values are based on Company Net Reserves. Net present value of reserves categories are an approximation based on major products.

(3) Including solution gas and other by-products.

(4) Including by-products but excluding solution gas.

Forecast Prices used in Estimates **(1)**

Year	WTI Cushing Oklahoma ($US/bbl)	Light Crude Oil and & Medium Crude Oil: Edmonton Par Price 40° API ($Cdn/bbl)	Light Crude Oil and & Medium Crude Oil: Cromer Medium 29.3° API ($Cdn/bbl)	Crude Oil: Brent Blend FOB North Sea ($US/bbl)	Conventional Natural Gas Canada: AECO Gas Price ($Cdn/MMBtu)	Conventional Natural Gas Europe: National Balancing Point (UK) ($US/MMBtu)	Natural Gas Liquids: FOB Field Gate ($Cdn/bbl)	Inflation Rate: Percent Per Year	Exchange Rate ($US/$Cdn)	Exchange Rate ($CdnEUR)
2016	43.30	52.95	48.71	45.01	2.19	4.65	34.50	1.50	0.76	1.47
Forecast										
2017	55.00	69.33	64.48	57.00	3.46	5.75	40.40	2.00	0.75	1.40
2018	59.00	72.26	67.20	61.00	3.10	6.00	41.41	2.00	0.78	1.35
2019	64.00	75.00	69.75	66.00	3.27	6.25	42.94	2.00	0.80	1.31
2020	67.00	76.36	71.02	70.00	3.49	6.50	43.77	2.00	0.83	1.27
2021	71.00	78.82	73.31	74.00	3.67	6.75	45.24	2.00	0.85	1.24
2022	74.00	82.35	76.59	77.00	3.86	6.89	47.30	2.00	0.85	1.24
2023	77.00	85.88	79.87	80.00	4.05	7.02	49.25	2.00	0.85	1.24
2024	80.00	89.41	83.15	83.00	4.16	7.16	51.23	2.00	0.85	1.24
2025	83.00	92.94	86.44	86.00	4.24	7.31	53.42	2.00	0.85	1.24
2026	86.05	95.61	88.92	89.64	4.32	7.45	54.80	2.00	0.85	1.24
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0%	0.850	1.235

Note:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth above. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

All forecast prices in the tables above are provided by GLJ. For 2016, the price of crude oil in the United States is based on WTI. The benchmark price for Canadian crude oil is Edmonton Par and Canadian natural gas is priced against AECO. The benchmark price for Australia and France crude oil is Dated Brent. The price of our natural gas in Ireland is based on the NBP index. The price of Vermilion's natural gas in the Netherlands is based on the TTF day-ahead index, as determined on the Title Transfer Facility Virtual Trading Point. The price of Vermilion's natural gas in Germany is based on the TTF, as determined on the Title Transfer Facility Virtual Trading Point. For the year ended December 31, 2016, the average realized sales prices before hedging were $46.89 per bbl (United States) for WTI, $43.58 per bbl for Canadian-based crude oil, condensate and NGLs and $2.14 per Mcf for Canadian natural gas, $60.33 per bbl (Australia), $55.42 per bbl (France) for Brent-based crude oil, $5.86 per Mcf (Ireland), $5.67 per Mcf (Netherlands), and $5.33 per Mcf (Germany).

Reconciliations of Changes in Reserves

The following tables set forth a reconciliation of the changes in Vermilion's gross light crude oil and medium crude oil, heavy oil, tight oil, conventional natural gas, coal bed methane, shale gas and NGLs reserves as at December 31, 2016 compared to such reserves as at December 31, 2015 based on the forecast price and cost assumptions set forth in note 3.

Reconciliation of Company Gross Reserves by Principal Product Type - Based on Forecast Prices and Costs

AUSTRALIA	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2015	13,765	3,700	17,465	13,765	3,700	17,465	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	700	1,300	2,000	700	1,300	2,000	-	-	-	-	-	-
Technical Revisions	260	(350)	(90)	260	(350)	(90)	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(2,307)	-	(2,307)	(2,307)	-	(2,307)	-	-	-	-	-	-
At December 31, 2016	12,418	4,650	17,068	12,418	4,650	17,068	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2015	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
At December 31, 2016	-	-	-	-	-	-	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2015	-	-	-	13,765	3,700	17,465
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	700	1,300	2,000
Technical Revisions	-	-	-	260	(350)	(90)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(2,307)	-	(2,307)
At December 31, 2016	-	-	-	12,418	4,650	17,068

CANADA	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**
At December 31, 2015	22,990	14,792	37,782	22,971	14,786	37,757	9	3	12	10	3	13
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	620	281	901	620	281	901	-	-	-	-	-	-
Technical Revisions	611	(1,284)	(673)	616	(1,280)	(664)	(9)	(3)	(12)	4	(1)	3
Acquisitions	206	317	523	206	317	523	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(15)	(1)	(16)	(15)	(1)	(16)	-	-	-	-	-	-
Production	(2,438)	-	(2,438)	(2,436)	-	(2,436)	-	-	-	(2)	-	(2)
At December 31, 2016	21,974	14,105	36,079	21,962	14,103	36,065	-	-	-	12	2	14

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**
At December 31, 2015	200,263	138,068	338,331	190,111	132,676	322,787	8,210	4,917	13,127	1,942	475	2,417
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	18,401	20,608	39,009	18,401	20,608	39,009	-	-	-	-	-	-
Technical Revisions	27,342	(8,022)	19,320	26,058	(7,696)	18,362	1,394	(135)	1,259	(110)	(191)	(301)
Acquisitions	13,078	6,758	19,836	13,006	6,671	19,677	72	87	159	-	-	-
Dispositions	(353)	(132)	(485)	(353)	(132)	(485)	-	-	-	-	-	-
Economic Factors	(1,351)	(612)	(1,963)	(649)	(420)	(1,069)	(702)	(192)	(894)	-	-	-
Production	(30,850)	-	(30,850)	(29,476)	-	(29,476)	(913)	-	(913)	(461)	-	(461)
At December 31, 2016	226,530	156,668	383,198	217,098	151,707	368,805	8,061	4,677	12,738	1,371	284	1,655

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved + Probable (Mboe)**
At December 31, 2015	14,795	12,751	27,546	71,162	50,554	121,717
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	1,412	825	2,237	5,099	4,541	9,640
Technical Revisions	2,004	(1,088)	916	7,172	(3,709)	3,463
Acquisitions	1,045	471	1,516	3,431	1,914	5,345
Dispositions	(8)	(3)	(11)	(67)	(25)	(92)
Economic Factors	(31)	(49)	(80)	(271)	(152)	(423)
Production	(1,854)	-	(1,854)	(9,434)	-	(9,434)
At December 31, 2016	17,363	12,907	30,270	77,092	53,123	130,215

FRANCE	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2015	40,721	21,325	62,046	40,721	21,325	62,046	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	2,279	314	2,593	2,279	314	2,593	-	-	-	-	-	-
Technical Revisions	3,445	319	3,764	3,445	319	3,764	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(47)	(25)	(72)	(47)	(25)	(72)	-	-	-	-	-	-
Production	(4,354)	-	(4,354)	(4,354)	-	(4,354)	-	-	-	-	-	-
At December 31, 2016	42,044	21,933	63,977	42,044	21,933	63,977	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2015	7,835	1,559	9,394	7,835	1,559	9,394	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	(2,170)	(654)	(2,824)	(2,170)	(654)	(2,824)	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(20)	(13)	(33)	(20)	(13)	(33)	-	-	-	-	-	-
Production	(163)	-	(163)	(163)	-	(163)	-	-	-	-	-	-
At December 31, 2016	5,482	892	6,374	5,482	892	6,374	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2015	-	-	-	42,027	21,585	63,612
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	2,279	314	2,593
Technical Revisions	-	-	-	3,083	210	3,293
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	(50)	(27)	(77)
Production	-	-	-	(4,381)	-	(4,381)
At December 31, 2016	-	-	-	42,958	22,082	65,040

GERMANY	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**
At December 31, 2015	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	244	755	999	244	755	999	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	5,044	1,524	6,568	5,044	1,524	6,568	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
At December 31, 2016	5,288	2,279	7,567	5,288	2,279	7,567	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**
At December 31, 2015	31,500	17,999	49,499	31,500	17,999	49,499	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	33,249	33,249	-	33,249	33,249	-	-	-	-	-	-
Technical Revisions	4,250	(898)	3,352	4,250	(898)	3,352	-	-	-	-	-	-
Acquisitions	11,182	3,934	15,116	11,182	3,934	15,116	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(5,452)	-	(5,452)	(5,452)	-	(5,452)	-	-	-	-	-	-
At December 31, 2016	41,480	54,284	95,764	41,480	54,284	95,764	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved + Probable (Mboe)**
At December 31, 2015	-	-	-	5,250	3,000	8,250
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	244	6,297	6,541
Technical Revisions	-	-	-	708	(150)	559
Acquisitions	-	-	-	6,909	2,179	9,087
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	-	-	-	(909)	-	(909)
At December 31, 2016	-	-	-	12,202	11,326	23,528

IRELAND	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**
At December 31, 2015	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
At December 31, 2016	-	-	-	-	-	-	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**
At December 31, 2015	105,821	47,405	153,226	105,821	47,405	153,226	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	3,714	2,718	6,432	3,714	2,718	6,432	-	-	-	-	-	-
Technical Revisions	8,610	721	9,331	8,610	721	9,331	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	57	(57)	-	57	(57)	-	-	-	-	-	-	-
Production	(18,627)	-	(18,627)	(18,627)	-	(18,627)	-	-	-	-	-	-
At December 31, 2016	99,575	50,787	150,362	99,575	50,787	150,362	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved + Probable (Mboe)**
At December 31, 2015	-	-	-	17,637	7,901	25,538
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	619	453	1,072
Technical Revisions	-	-	-	1,435	121	1,556
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	10	(10)	-
Production	-	-	-	(3,105)	-	(3,105)
At December 31, 2016	-	-	-	16,596	8,465	25,061

NETHERLANDS	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2015	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	-	-	-	-	-	-	-
At December 31, 2016	-	-	-	-	-	-	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2015	48,199	48,688	96,887	48,199	48,688	96,887	-	-	-	-	-	-
Discoveries	233	145	378	233	145	378	-	-	-	-	-	-
Extensions & Improved Recovery	8,104	8,782	16,886	8,104	8,782	16,886	-	-	-	-	-	-
Technical Revisions	20,790	(15,818)	4,972	20,790	(15,818)	4,972	-	-	-	-	-	-
Acquisitions	2,654	1,446	4,100	2,654	1,446	4,100	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(128)	(59)	(187)	(128)	(59)	(187)	-	-	-	-	-	-
Production	(17,502)	-	(17,502)	(17,502)	-	(17,502)	-	-	-	-	-	-
At December 31, 2016	62,350	43,184	105,534	62,350	43,184	105,534	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2015	88	83	171	8,122	8,198	16,320
Discoveries	1	1	2	40	25	65
Extensions & Improved Recovery	3	7	10	1,353	1,470	2,823
Technical Revisions	17	(31)	(14)	3,482	(2,667)	815
Acquisitions	5	3	8	447	244	691
Dispositions	-	-	-	-	-	-
Economic Factors	(1)	(0)	(1)	(22)	(10)	(32)
Production	(32)	-	(32)	(2,949)	-	(2,949)
At December 31, 2016	81	63	144	10,473	7,260	17,733

UNITED STATES	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**
At December 31, 2015	2,034	3,818	5,852	2,034	3,818	5,852	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	1,105	1,644	2,749	1,105	1,644	2,749	-	-	-	-	-	-
Technical Revisions	178	271	449	178	271	449	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(4)	(6)	(10)	(4)	(6)	(10)	-	-	-	-	-	-
Production	(144)	-	(144)	(144)	-	(144)	-	-	-	-	-	-
At December 31, 2016	3,169	5,727	8,896	3,169	5,727	8,896	-	-	-	-	-	-

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved + Probable (MMcf)**
At December 31, 2015	2,170	4,378	6,548	2,170	4,378	6,548	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	1,011	1,578	2,589	1,011	1,578	2,589	-	-	-	-	-	-
Technical Revisions	(129)	(460)	(589)	(129)	(460)	(589)	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(6)	(15)	(21)	(6)	(15)	(21)	-	-	-	-	-	-
Production	(77)	-	(77)	(77)	-	(77)	-	-	-	-	-	-
At December 31, 2016	2,969	5,481	8,450	2,969	5,481	8,450	-	-	-	-	-	-

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved + Probable (Mboe)**
At December 31, 2015	346	698	1,044	2,742	5,246	7,988
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	141	219	360	1,415	2,127	3,541
Technical Revisions	(62)	(155)	(217)	94	39	134
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(2)	(2)	(4)	(7)	(11)	(18)
Production	(11)	-	(11)	(168)	-	(168)
At December 31, 2016	412	760	1,172	4,076	7,401	11,477

TOTAL COMPANY	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
At December 31, 2015	79,510	43,635	123,145	79,491	43,629	123,120	9	3	12	10	3	13
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery	4,948	4,294	9,242	4,948	4,294	9,242	-	-	-	-	-	-
Technical Revisions	4,492	(1,044)	3,450	4,499	(1,040)	3,459	(9)	(3)	(12)	4	(1)	3
Acquisitions	5,250	1,841	7,091	5,250	1,841	7,091	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(66)	(32)	(98)	(66)	(32)	(98)	-	-	-	-	-	-
Production	(9,243)	-	(9,243)	(9,241)	-	(9,241)	-	-	-	(2)	-	(2)
At December 31, 2016	84,891	48,694	133,587	84,881	48,692	133,573	-	-	-	12	2	14

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2] Factors	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
At December 31, 2015	395,788	258,097	653,885	385,637	252,705	638,342	8,210	4,917	13,127	1,942	475	2,417
Discoveries	233	145	378	233	145	378	-	-	-	-	-	-
Extensions & Improved Recovery	31,230	66,935	98,165	31,230	66,935	98,165	-	-	-	-	-	-
Technical Revisions	58,693	(25,131)	33,562	57,408	(24,805)	32,603	1,394	(135)	1,259	(110)	(191)	(301)
Acquisitions	26,914	12,138	39,052	26,842	12,051	38,893	72	87	159	-	-	-
Dispositions	(353)	(132)	(485)	(353)	(132)	(485)	-	-	-	-	-	-
Economic Factors	(1,448)	(756)	(2,204)	(746)	(564)	(1,310)	(702)	(192)	(894)	-	-	-
Production	(72,671)	-	(72,671)	(71,297)	-	(71,297)	(913)	-	(913)	(461)	-	(461)
At December 31, 2016	438,386	311,296	749,682	428,954	306,335	735,289	8,061	4,677	12,738	1,371	284	1,655

	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2] Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2015	15,229	13,532	28,761	160,706	100,184	260,889
Discoveries	1	1	2	40	25	65
Extensions & Improved Recovery	1,556	1,051	2,607	11,709	16,502	28,210
Technical Revisions	1,959	(1,274)	685	16,233	(6,506)	9,730
Acquisitions	1,050	474	1,524	10,787	4,337	15,123
Dispositions	(8)	(3)	(11)	(67)	(25)	(92)
Economic Factors	(34)	(51)	(85)	(340)	(210)	(550)
Production	(1,897)	-	(1,897)	(23,253)	-	(23,253)
At December 31, 2016	17,856	13,730	31,586	175,815	114,307	290,122

Notes:

(1) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(2) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

(3) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth above. See “Forecast Prices used in Estimates”. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(4) For reporting purposes, “Total Oil” is the sum of Light Crude oil and Medium Crude Oil, Heavy Oil and Tight Oil. For reporting purposes, “Total Gas” is the sum of Conventional Natural Gas, Coal Bed Methane and Shale Gas.

(5) “Coal Bed Methane” and “Shale Gas” were considered “Unconventional Natural Gas” in previous years. NI 51-101 no longer differentiates between conventional and unconventional activities.

Undeveloped Reserves

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. These reserves have a 90% probability of being recovered. Vermilion's current plan is to develop these reserves in the following three years. The pace of development of these reserves is influenced by many factors, including but not limited to, the outcomes of yearly drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, regulatory changes and impact of future acquisitions and dispositions. As new information becomes available these reserves are reviewed and development plans are revised accordingly.

Probable undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. These reserves have a 50% probability of being recovered. Vermilion's current plan is to develop these reserves over the next five years. In general, development of these reserves requires additional evaluation data to increase the probability of success to an acceptable level for Vermilion. This increases the timeline for the development of these reserves. This timetable may be altered depending on outside market forces, changes in capital allocations and impact of future acquisitions and dispositions.

Timing of Initial Undeveloped Reserves Assignment

Undeveloped Reserves Attributed in Current Year

	Light Crude Oil & Medium Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Coal Bed Methane (MMcf)		Natural Gas Liquids (Mbbl)		Total Oil Equivalent (Mboe)	
	First Attributed [1]	Booked	First Attributed [1]	Booked	First Attributed [1]	Booked	First Attributed [1]	Booked	First Attributed [1]	Booked
Proved										
Prior to 2013	11,370	23,777	23,698	344,017	4,943	35,348	839	2,545	16,983	89,550
2013	4,293	13,007	38,720	167,927	8,191	12,389	3,543	4,734	15,655	47,793
2014	5,614	15,434	26,111	170,763	-	11,610	2,175	7,942	12,140	53,772
2015	4,182	15,989	30,963	78,022	333	3,367	2,500	7,287	11,898	36,842
2016	1,411	16,140	25,023	90,934	-	3,043	1,737	7,546	7,318	39,348
Probable										
Prior to 2013	15,923	45,687	28,011	161,341	2,435	22,167	982	3,144	21,980	79,417
2013	7,967	17,797	53,927	115,066	5,338	7,085	3,742	4,640	21,587	42,795
2014	6,541	22,050	60,779	163,645	-	6,741	3,762	9,615	20,432	60,063
2015	6,118	25,126	50,125	122,802	57	2,949	5,708	10,965	20,190	57,050
2016	4,918	27,863	66,129	167,973	-	3,328	1,611	10,506	17,550	66,919

Note:

[1] "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year

Future Development Costs [(1)]

The table below sets out the future development costs deducted in the estimation of future net revenue attributable to total proved reserves and total proved plus probable reserves (using forecast prices and costs).

(M$)	Total Proved Estimated Using Forecast Prices and Costs	Total Proved Plus Probable Estimated Using Forecast Prices and Costs
Australia		
2017	9,420	9,420
2018	6,701	6,701
2019	51,052	51,052
2020	2,993	2,993
2021	3,052	57,174
Remainder	25,062	48,320
Total for all years undiscounted	98,280	175,660
Canada		
2017	77,141	101,695
2018	90,442	126,482
2019	81,623	128,701
2020	95,424	189,622
2021	59,376	175,978
Remainder	17,542	51,883
Total for all years undiscounted	421,548	774,361
France		
2017	39,113	60,593
2018	29,528	49,613
2019	23,548	107,737
2020	6,753	40,020
2021	14,167	23,931
Remainder	10,363	35,668
Total for all years undiscounted	123,472	317,562
Germany		
2017	2,183	3,562
2018	584	3,272
2019	8,499	30,655
2020	154	6,863
2021	153	41,162
Remainder	694	3,167
Total for all years undiscounted	12,267	88,681
Ireland		
2017	1,311	1,311
2018	-	-
2019	1,706	1,706
2020	16,890	16,890
2021	-	-
Remainder	15,505	15,505
Total for all years undiscounted	35,412	35,412
Netherlands		
2017	2,200	7,790
2018	13,525	15,009
2019	604	4,838
2020	385	4,278
2021	287	8,095
Remainder	5,638	5,637
Total for all years undiscounted	22,639	45,647
United States		
2017	10,500	10,500
2018	18,426	36,468
2019	18,207	48,039
2020	13,506	42,806
2021	-	-
Remainder	-	1
Total for all years undiscounted	60,639	137,814
Total Company		
2017	141,868	194,871
2018	159,206	237,545
2019	185,239	372,728
2020	136,105	303,472
2021	77,035	306,340
Remainder	74,804	160,181
Total for all years undiscounted	774,257	1,575,137

Note:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth above. See "Forecast Prices used in Estimates". The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

Vermilion expects to source its capital expenditure requirements from internally generated cash flow and, as appropriate, from Vermilion's existing credit facility or equity or debt financing. It is anticipated that costs of funding the future development costs will not impact development of its properties or Vermilion's reserves or future net revenue.

Oil and Gas Properties and Wells [(1) (2)]

The following table sets forth the number of wells in which Vermilion held a working interest as at December 31, 2016:

	Oil				Gas			
	Producing		Non-Producing [(5)]		Producing		Non-Producing [(5)]	
	Gross Wells [(3)]	Net Wells [(4)]	Gross Wells [(3)]	Net Wells [(4)]	Gross Wells [(3)]	Net Wells [(4)]	Gross Wells [(3)]	Net Wells [(4)]
Canada								
Alberta	471	326	166	99	523	358	405	307
Saskatchewan	140	119	22	20	-	-	-	-
Total Canada	611	445	188	119	523	358	405	307
Australia	18	18	-	-	-	-	-	-
France	336	331	84	83	3	3	-	-
Germany	141	111	24	11	20	7	6	3
Ireland	-	-	-	-	6	1	-	-
Netherlands	-	-	-	-	54	37	12	11
United States (Wyoming)	11	9	2	1	-	-	-	-
Total Vermilion	1,117	914	298	214	606	406	423	321

Notes:

(1) Well counts are based on wellbores.

(2) Wells for Australia and Ireland are located offshore.

(3) "Gross" refers to the total wells in which Vermilion has an interest, directly or indirectly.

(4) "Net" refers to the total wells in which Vermilion has an interest, directly or indirectly, multiplied by the percentage working interest owned by Vermilion, directly or indirectly, therein.

(5) Non-producing wells include wells which are capable of producing, but which are currently not producing, and are re-evaluated with respect to future commodity prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Costs Incurred

The following table summarizes the capital expenditures made by Vermilion on oil and gas properties for the year ended December 31, 2016:

	Acquisition Costs				
(M$)	**Proved Properties**	**Unproved Properties**	**Exploration Costs**	**Development Costs**	**Total Costs**
Australia	-	-	-	59,910	59,910
Canada	13,309	-	-	62,706	76,015
Croatia	-	-	2,968	-	2,968
France	-	-	-	68,472	68,472
Germany	48,377	-	-	3,803	52,180
Hungary	-	-	338	-	338
Ireland	-	-	-	9,375	9,375
Netherlands	28,259	-	-	23,740	51,999
United States	5,935	-	-	13,539	19,474
Total	95,880	-	3,306	241,545	340,731

Acreage

The following table summarizes the acreage for the year ended December 31, 2016:

	Developed [1]		Undeveloped		Total	Total
	Gross [2]	**Net [3]**	**Gross [2]**	**Net [3]**	**Gross [2]**	**Net**
Australia	20,164	20,164	39,389	39,389	59,553	59,553
Canada	445,898	328,530	500,251	443,116	946,149	771,646
Croatia	-	-	2,348,984	2,348,984	2,348,984	2,348,984
France	218,110	208,858	336,595	336,595	554,705	545,453
Germany	67,634	25,798	2,609,304	1,054,905	2,676,938	1,080,703
Hungary	-	-	322,142	322,142	322,142	322,142
Ireland	7,200	1,300	-	-	7,200	1,300
Netherlands	80,725	48,539	1,411,744	792,942	1,492,469	841,481
Slovakia	-	-	183,000	91,500	183,000	91,500
United States	4,368	4,031	104,128	93,121	108,496	97,152
Total	844,099	637,220	7,855,537	5,522,694	8,699,636	6,159,914

Notes:

(1) "Developed" means the acreage assigned to productive wells based on applicable regulations.

(2) "Gross" means the total acreage in which Vermilion has a working interest, directly or indirectly.

(3) "Net" means the total acreage in which Vermilion has a working interest, directly or indirectly, multiplied by the percentage working interest of Vermilion.

Exploration and Development Activities

The following table sets forth the number of development and exploration wells which Vermilion completed during its 2016 financial year:

	Exploration Wells		Development Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Australia				
Oil	-	-	2.0	2.0
Gas	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	2.0	2.0
Canada				
Oil	-	-	9.0	5.6
Gas	-	-	20.0	12.0
Dry Holes	-	-	-	-
Total Completed	-	-	29.0	17.6
France				
Oil	-	-	4.0	4.0
Gas	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	4.0	4.0
Germany				
Oil	-	-	-	-
Gas	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	-	-
Ireland				
Oil	-	-	-	-
Gas	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	-	-
Netherlands				
Oil	-	-	-	-
Gas	-	-	1.0	0.4
Dry Holes	-	-	1.0	0.5
Total Completed	-	-	2.0	0.9
United States				
Oil	-	-	1.0	1.0
Gas	-	-	-	-
Dry Holes	-	-	-	-
Total Completed	-	-	1.0	1.0
Total Company				
Oil	-	-	16.0	12.6
Gas	-	-	21.0	12.4
Dry Holes	-	-	1.0	0.5
Total Completed	-	-	38.0	25.5

Notes:

(1) "Gross" refers to the total wells in which Vermilion has an interest, directly or indirectly.

(2) "Net" refers to the total wells in which Vermilion has an interest, directly or indirectly, multiplied by the percentage working interest owned by Vermilion, directly or indirectly therein.

Please see "Description of the Business - Operating Segments and Description of Properties" for a general description of the Company's current and likely exploration and development activities.

Properties with No Attributed Reserves

The following table sets out Vermilion's properties with no attributed reserves as at December 31, 2016:

	Properties with No Attributed Reserves	
Country	**Gross Acres (1)**	**Net Acres**
Australia	31,838	31,838
Canada	244,671	216,726
Croatia	2,348,984	2,348,984
France	229,239	229,239
Germany	2,565,069	1,037,022
Hungary	322,142	322,142
Ireland	-	-
Netherlands	1,367,670	768,187
Slovakia	183,000	91,500
United States	95,944	85,802
Total	7,388,557	5,131,440

Notes:

(1) "Gross" refers to the total acres in which Vermilion has an interest, directly or indirectly.

(2) "Net" refers to the total acres in which Vermilion has an interest, directly or indirectly, multiplied by the percentage working interest owned by Vermilion, directly or indirectly therein.

Vermilion expects its rights to explore, develop and exploit approximately 71,400 (70,100 net) acres in Canada, 2,675 (2,675 net) acres in the United States, 18,285 (18,285 net) acres in France, and 19,667 (8,845 net) acres in Germany to expire within one year, unless the Company initiates the capital activity necessary to retain the rights. Work commitments on these lands are categorized as seismic acquisition, geophysical studies or well commitments. No such rights are expected to expire within one year for Australia, Croatia, Hungary, Ireland and the Netherlands. Vermilion currently has no material work commitments in Australia, Canada and the United States. Vermilion's work commitments with respect to its European lands held are estimated to be $15.1 million in the next year.

Vermilion's properties with no attributed reserves do not have any significant abandonment and reclamation costs in any country other than Canada, which has a net estimated cost of $17.7 million. All properties with no attributed reserves do not have high expected development or operating costs or contractual sales obligations to produce and sell at substantially lower prices than could be realized.

Tax Information

Vermilion pays current taxes in France, the Netherlands and Australia. Corporate income taxes in France and the Netherlands apply to taxable income after eligible deductions. In France, taxable income is taxed at 34.4%. In 2012, the France government enacted a new 3% tax on dividend distributions made by entities subject to corporate income tax in France. The tax applies to any dividends paid on or after April 17, 2012 and is not recovered by any tax treaties or deductible for French corporate income tax purposes. In late December 2016, the France government passed legislation, the effect of which will exempt any dividend distributions made by Vermilion after January 1, 2017 from the 3% tax. Vermilion did not pay any dividends from its French entities in 2016. In the Netherlands, current income taxes are applied to taxable income, after eligible deductions and a 10% uplift deduction applied to operating expenses, eligible general and administration expenses and tax deductions for depletion and abandonment retirement obligations, at a tax rate 50%. As a function of the impact of Vermilion's tax pools, the Company does not presently pay current taxes in Canada, Germany, Ireland and the United States. The Canadian segment includes holding companies that pay current taxes in foreign jurisdictions.

In Australia, current taxes include both corporate income taxes and PRRT. Corporate income taxes are applied at a rate of approximately 30% on taxable income after eligible deductions, which include PRRT paid. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures.

The following table sets forth Vermilion's tax pools as at December 31, 2016:

(M$)	Oil and Gas Assets	Tax Losses	Other	Total
Australia	276,911 (1)	-	-	276,911
Canada	978,949 (1)	489,702 (5)	32,503	1,501,154
France	351,551 (2)	13,360 (6)	-	364,911
Germany	190,002 (3)	57,156 (7)	20,306	267,464
Ireland	942,129 (4)	403,779 (5)	-	1,345,908
Netherlands	68,139 (3)	-	-	68,139
United States	34,885 (1)	30,328 (5)	797	66,010
Total	2,842,566	994,325	53,606	3,890,497

Notes:
(1) Deduction calculated using various declining balance rates
(2) Deduction calculated using a combination of straight-line over the assets life and unit of production method
(3) Deduction calculated using a unit of production method
(4) Deduction for current development expenditures and tax losses at 100% against taxable income
(5) Tax losses can be carried forward at 100% against taxable income
(6) Tax losses carried forward are available to offset the first €1 million of taxable income and 50% of taxable profits in excess each taxation year
(7) Tax losses carried forward are available to offset the first €1 million of taxable income and 60% of taxable profits in excess each taxation year

Production Estimates

The following table sets forth the volume of production estimated for the year ended December 31, 2017 as reflected in the estimates of gross proved reserves and gross proved plus probable reserves in the GLJ Report:

	Light Crude Oil & Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d)	Tight Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Australia								
Proved	5,791	-	-	-	-	-	-	5,791
Proved Plus Probable	5,932	-	-	-	-	-	-	5,932
Canada								
Proved	5,957	-	4	81,102	551	2,623	6,597	26,604
Proved Plus Probable	6,655	-	5	90,765	569	2,827	7,570	29,923
France								
Proved	12,287	-	-	1,234	-	-	-	12,492
Proved Plus Probable	13,288	-	-	1,247	-	-	-	13,496
Germany								
Proved	1,078	-	-	18,170	-	-	-	4,107
Proved Plus Probable	1,122	-	-	19,045	-	-	-	4,296
Ireland								
Proved	-	-	-	57,175	-	-	-	9,529
Proved Plus Probable	-	-	-	59,025	-	-	-	9,838
Netherlands								
Proved	-	-	-	46,831	-	-	81	7,886
Proved Plus Probable	-	-	-	54,155	-	-	101	9,127
United States								
Proved	570	-	-	407	-	-	56	694
Proved Plus Probable	670	-	-	461	-	-	64	810
Total Proved	25,683	-	4	204,919	551	2,623	6,734	67,103
Total Proved Plus Probable	27,667	-	5	224,698	569	2,827	7,735	73,422

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by Vermilion for each quarter of its most recently completed financial year. Light crude oil and medium crude oil average net prices received in the following table also includes immaterial amounts generated by the sale of heavy oil.

	Three Months Ended March 31, 2016	Three Months Ended June 30, 2016	Three Months Ended September 30, 2016	Three Months Ended December 31, 2016
Australia				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	6,180	6,083	6,562	6,388
Conventional Natural Gas (MMcf/d)	-	-	-	-
Natural Gas Liquids (bbl/d)	-	-	-	-
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	46.93	61.53	60.61	69.05
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	17.63	22.08	17.59	26.83
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	29.30	39.45	43.02	42.22
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Canada				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	8,231	6,965	6,406	5,004
Conventional Natural Gas (MMcf/d)	97.16	87.44	77.62	75.12
Natural Gas Liquids (bbl/d)	4,719	5,175	5,026	5,385
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	38.94	58.92	54.38	61.97
Conventional Natural Gas ($/Mcf)	1.93	1.34	2.39	3.05
Natural Gas Liquids ($/bbl)	25.32	29.69	32.85	38.59
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	4.44	4.36	3.33	6.53
Conventional Natural Gas ($/Mcf)	0.08	(0.06)	0.14	0.22
Natural Gas Liquids ($/bbl)	3.50	3.22	4.05	5.70
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.76	2.87	3.12	2.84
Conventional Natural Gas ($/Mcf)	0.16	0.16	0.18	0.18
Natural Gas Liquids ($/bbl)	1.70	1.39	1.82	1.70
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	8.87	9.10	10.55	9.91
Conventional Natural Gas ($/Mcf)	1.44	1.06	0.95	1.32
Natural Gas Liquids ($/bbl)	5.24	4.93	5.47	8.94
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	22.87	42.59	37.38	42.69
Conventional Natural Gas ($/Mcf)	0.25	0.18	1.12	1.32
Natural Gas Liquids ($/bbl)	14.88	20.15	21.51	22.25

France				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	12,220	12,326	11,827	11,220
Conventional Natural Gas (MMcf/d)	0.44	0.54	0.42	0.38
Natural Gas Liquids (bbl/d)	-	-	-	-
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	43.36	58.19	56.14	63.99
Conventional Natural Gas ($/Mcf)	1.66	1.58	1.58	1.55
Natural Gas Liquids ($/bbl)	-	-	-	-
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	6.09	6.19	6.08	5.95
Conventional Natural Gas ($/Mcf)	0.29	0.39	0.32	0.36
Natural Gas Liquids ($/bbl)	-	-	-	-
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.35	3.29	3.09	3.55
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	12.84	10.55	11.06	10.13
Conventional Natural Gas ($/Mcf)	2.24	2.27	2.55	3.12
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	21.08	38.16	35.91	44.36
Conventional Natural Gas ($/Mcf)	(0.87)	(1.08)	(1.29)	(1.93)
Natural Gas Liquids ($/bbl)	-	-	-	-
Germany				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	-	-	-	-
Conventional Natural Gas (MMcf/d)	15.96	14.31	14.52	14.80
Natural Gas Liquids (bbl/d)	-	-	-	-
Average Net Prices Received	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	5.30	4.82	5.08	6.09
Natural Gas Liquids ($/bbl)	-	-	-	-
Royalties	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	0.60	0.74	0.18	0.01
Natural Gas Liquids ($/bbl)	-	-	-	-
Transportation	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	0.61	0.81	0.42	0.28
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	1.79	1.92	2.49	2.91
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	2.30	1.35	1.99	2.89
Natural Gas Liquids ($/bbl)	-	-	-	-

Ireland				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	-	-	-	-
Conventional Natural Gas (MMcf/d)	33.90	47.26	59.28	62.92
Natural Gas Liquids (bbl/d)	-	-	-	-
Average Net Prices Received	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	5.51	5.43	4.78	7.38
Natural Gas Liquids ($/bbl)	-	-	-	-
Royalties	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Transportation	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	0.53	0.37	0.29	0.29
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	1.18	1.20	0.86	0.89
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received	-	-	-	-
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	3.80	3.86	3.63	6.20
Natural Gas Liquids ($/bbl)	-	-	-	-
Netherlands				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	-	-	-	-
Conventional Natural Gas (MMcf/d)	53.40	49.18	47.62	41.15
Natural Gas Liquids (bbl/d)	114	96	86	57
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	5.55	5.27	5.27	6.78
Natural Gas Liquids ($/bbl)	32.24	45.05	49.43	63.18
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	0.09	0.09	0.07	0.08
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	1.23	0.96	1.11	1.49
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	4.23	4.22	4.09	5.21
Natural Gas Liquids ($/bbl)	32.24	45.05	49.43	63.18

United States				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	368	458	383	362
Conventional Natural Gas (MMcf/d)	0.26	0.20	0.20	0.18
Natural Gas Liquids (bbl/d)	39	26	30	23
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	35.80	52.56	51.29	59.09
Conventional Natural Gas ($/Mcf)	0.67	0.37	0.64	1.93
Natural Gas Liquids ($/bbl)	4.81	3.25	5.14	19.48
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	10.47	15.47	14.69	17.24
Conventional Natural Gas ($/Mcf)	0.40	0.18	0.39	1.72
Natural Gas Liquids ($/bbl)	2.70	5.21	(0.11)	4.51
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	-	-	-	-
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	8.33	7.22	12.27	9.04
Conventional Natural Gas ($/Mcf)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	17.00	29.87	24.33	32.81
Conventional Natural Gas ($/Mcf)	0.27	0.19	0.25	0.21
Natural Gas Liquids ($/bbl)	2.11	(1.96)	5.25	14.97
Total				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	26,999	25,832	25,178	22,974
Conventional Natural Gas (MMcf/d)	201.11	198.93	199.65	194.54
Natural Gas Liquids (bbl/d)	4,872	5,297	5,142	5,465
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	42.59	59.09	56.96	65.90
Conventional Natural Gas ($/Mcf)	3.76	3.53	3.98	5.47
Natural Gas Liquids ($/bbl)	25.32	29.84	32.96	38.80
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	4.50	4.35	3.77	4.87
Conventional Natural Gas ($/Mcf)	0.11	0.05	0.09	0.10
Natural Gas Liquids ($/bbl)	3.44	3.22	3.99	5.68
Transportation Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.49	2.32	2.15	2.50
Conventional Natural Gas ($/Mcf)	0.22	0.22	0.19	0.19
Natural Gas Liquids ($/bbl)	1.65	1.36	1.78	1.67
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	12.49	12.87	12.86	14.45
Conventional Natural Gas ($/Mcf)	1.37	1.13	1.08	1.34
Natural Gas Liquids ($/bbl)	5.09	4.81	5.34	8.79
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	23.11	39.55	38.18	44.08
Conventional Natural Gas ($/Mcf)	2.06	2.13	2.62	3.84
Natural Gas Liquids ($/bbl)	15.14	20.45	21.85	22.66

Marketing

The nature of Vermilion's operations results in exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates. Vermilion monitors and, when appropriate, uses derivative financial instruments to manage its exposure to these fluctuations. All transactions of this nature entered into by Vermilion are related to an underlying financial position or to future crude oil and natural gas production. Vermilion does not use derivative financial instruments for speculative purposes. Vermilion has not obtained collateral or other security to support its financial derivatives as management reviews the creditworthiness of its counterparties prior to entering into derivative contracts.

During the normal course of business, Vermilion may also enter into fixed price arrangements to sell a portion of its production or purchase commodities for operational use.

Vermilion's outstanding risk management positions as at December 31, 2016 are summarized in Supplemental Table 2: Hedges, included in the Company's 2016 Management's Discussion and Analysis, dated February 24, 2017, available on SEDAR at www.sedar.com, under Vermilion's SEDAR profile.

DIRECTORS AND OFFICERS

As at January 31, 2017, the directors and officers of Vermilion, as a group, beneficially owned, or controlled or directed, directly or indirectly, 3,903,713 common shares representing approximately 3.3% of the issued and outstanding common shares.

Set forth below is certain information respecting the current directors and officers of Vermilion. References to Vermilion in the following tables for dates prior to the Conversion Arrangement refer to VRL and to the Company following the date of the Conversion Arrangement.

Directors

Vermilion's board of directors currently consists of ten directors. The directors are nominated by the Company and elected annually by Shareholders and hold office until the next annual meeting of Shareholders, or until their successors are elected or appointed.

Name and Municipality of Residence	Committee(s)	Office Held	Year First Elected or Appointed as Director	Principal Occupation During the Past Five Years
Lorenzo Donadeo Calgary, Alberta Canada	(1)	Chairman of the Board	1994	Since March 1, 2016, Chairman of the Board of Vermilion March 2014 – March 1, 2016 Chief Executive Officer of Vermilion 2003 – March 2014, President and Chief Executive Officer of Vermilion
Claudio A. Ghersinich Calgary, Alberta Canada	(3) (6)	Director	1994	Since 2011, Chairman of ArPetrol Ltd., a public oil and gas company Since 2010, Director of Valeura Energy Inc., a public oil and gas company Since 2005, President of Carrera Investments Corp., a private investment company
Loren M. Leiker Houston, Texas USA	(6)	Director	2012	Since 2014, Director of Navitas Midstream Partners LLC Since 2012, Director of SM Energy, a public energy company 2012 to 2015, Director of Midstates Petroleum, a public exploration and production company 2008 to 2011, Senior Executive VP Exploration, EOG Resources, a public oil and gas company
Larry J. Macdonald Okotoks, Alberta Canada	(2) (3) (4) (5) (6)	Lead Director	2002	Since March 1, 2016, Lead Director of Vermilion 2012 to March 1, 2016, Chairman of the Board of Vermilion 2012 to 2016, Chairman Northpoint Resources, a private oil and gas company Since 2003, Chairman & Chief Executive Officer and Director of Point Energy Ltd., a private oil and gas company 2006 to 2013, Director of Sure Energy Inc.
William F. Madison Sugar Land, Texas USA	(5) (6)	Director	2004	Since 2011, Director of Montana Tech Foundation, an independent, non-profit organization Since 2007, Director of Canadian Oil Recovery and Remediation Enterprise, Inc., a public oil recovery and remediation company
Timothy R. Marchant Calgary, Alberta Canada	(5) (6)	Director	2010	Since 2015, Director, Valeura Energy Inc., a public oil and gas company Since 2013, Non-Executive Director of Cub Energy Inc., a public oil and gas company Since 2009, Adjunct Professor of Strategy and Energy Geopolitics, Haskayne School of Business 2011 to 2013, Executive Chair of Anatolia Energy Corp., a public oil and gas company
Anthony W. Marino Calgary, Alberta Canada		President & Chief Executive Officer and Director	2016	Since March 1, 2016, President and Chief Executive Officer March 2014 – March 1, 2016, President and Chief Operating Officer of Vermilion June 2012 – March 2014, Executive Vice President and Chief Operating Officer of Vermilion 2009 to 2012, Director, President & CEO, Baytex Energy Corporation, a public oil and gas company

Robert Michaleski Calgary, Alberta Canada	(3)	Director	2016	Since 2013, Director of United Way of Calgary and Area, a non-profit organization 2012 to 2013, Chief Executive Officer of Pembina Pipeline Corporation, a public energy transportation company 2000 to 2012, President and Chief Executive Officer of Pembina Pipeline Corporation Since 2012, Director of Essential Energy Services Ltd., a public oilfield services company Since 2003, Director of Coril Holdings Ltd., a private investment company Since 2000, Director of Pembina Pipeline Corporation
Sarah E. Raiss Calgary, Alberta Canada	(4) (5)	Director	2014	Since 2016, Director, Ritchie Bros. Auctioneers, a public heavy equipment auction company. Since 2014, Director, Loblaw Companies Limited, a public food distributor company Since 2011, Director, Commercial Metals Company, a public global, metals recycling, manufacturing, fabricating and trading company 2012 to 2015, Board Chair, Alberta Electric Systems Operator, a not-for-profit entity responsible for the planning and operation of the Alberta Interconnected Electric System 2012 to February 2016, Director, Canadian Oil Sands Limited, a public oil company 2009 to 2014, Director, Shoppers Drug Mart Corporation, a public pharmacy products and services company
Catherine L. Williams Calgary, Alberta Canada	(3) (4)	Director	2015	Since 2016, Director of Enbridge Income Fund, an energy infrastructure asset investment vehicle Since 2015, Director of Enbridge Pipelines Inc., a subsidiary of Enbridge Inc., a public energy transportation company Since 2015, Trustee of Enbridge Commercial Trust, a subsidiary of Enbridge Inc., a public energy transportation company Since 2015, Director of Enbridge Income Partners GP Inc., a subsidiary of Enbridge Inc., a public energy transportation company Since 2010, Chair of Human Resources and Compensation Committee, Enbridge Inc., a public energy transportation company Since 2007, Director of Enbridge Inc., a public energy transportation company Since 2007, Owner and Managing Director, Options Canada Ltd., a private investment company 2009 to 2014, Director, Alberta Investment Management Corporation, an institutional investment fund manager 2009 to 2012, Director, Tim Hortons Inc., a publicly-traded restaurant chain in North America

Committees:
(1) Chairman of the Board
(2) Lead Director
(3) Member of the Audit Committee
(4) Member of the Governance and Human Resources Committee
(5) Member of the Health, Safety and Environment Committee
(6) Member of the Independent Reserves Committee

Officers

Name and Municipality of Residence	**Office Held**	**Principal Occupation During the Past Five Years**
Anthony W. Marino Calgary, Alberta Canada	President & Chief Executive Officer	Since March 1, 2016, President and Chief Executive Officer March 2014 – March 1, 2016, President and Chief Operating Officer of Vermilion June 2012 – March 2014, Executive Vice President and Chief Operating Officer of Vermilion 2009 to 2012, Director, President & CEO, Baytex Energy Corporation, a public oil and gas company
Curtis W. Hicks Calgary, Alberta Canada	Executive Vice President & Chief Financial Officer	Since 2004, Executive Vice President and Chief Financial Officer of Vermilion
Mona Jasinski Calgary, Alberta Canada	Executive Vice President People & Culture	Since February 2015, Executive Vice President, People and Culture 2011 to 2015, Executive Vice President People of Vermilion
Michael Kaluza Calgary, Alberta Canada	Executive Vice President & Chief Operating Officer	Since March 1, 2016, Executive Vice President and Chief Operating Officer May 2014 – March 1, 2016, Vice President, Canada Business Unit of Vermilion 2013 to 2014, Director Canada Business Unit of Vermilion 2012 to 2013, Vice President, Corporate Development and Planning, Baytex Energy Corporation, a public oil and gas company 2011 to 2012, Vice President, Planning, Baytex Energy Corporation, a public oil and gas company
Anthony (Dion) Hatcher Calgary, Alberta Canada	Vice President Canada Business Unit	Since March 1, 2016, Vice President Canada Business Unit May 1, 2014 to March 1, 2016, Director Alberta Foothills – Canada Business Unit February 2013 to May 2014, Cardium / LRG Development Manager January 2010 to February 2013 – Cardium Development Manager
Terry Hergott Calgary, Alberta Canada	Vice President Marketing	Since April 2012, Vice President, Marketing of Vermilion 1998 to 2012, Canadian Supply and Trading Manager, Marathon Petroleum Corp.
Gerard Schut Den Haag The Netherlands	Vice President European Operations	Since July 2012, Vice President European Operations of Vermilion August 2006 to May 2012, General Manager, Chevron Exploration and Production Netherlands, a subsidiary of Chevron Corporation, a public oil and gas company
Robert J. Engbloom, Q.C. Calgary, Alberta Canada	Corporate Secretary	Since January 2015, senior partner with Norton Rose Fulbright Canada LLP, a law firm 2012 to 2014, partner with and Deputy Chair of Norton Rose Fulbright Canada LLP, a law firm

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

The Company is authorized to issue an unlimited number of common shares. Each common share entitles the holder to receive notice of and to attend all meetings of Shareholders and to one vote at any such meeting. The holders of common shares are, at the discretion of the board and subject to applicable legal restrictions, entitled to receive any dividends declared by the board on the common shares. The holders of common shares will be entitled to share equally in any distribution of the assets of the Company upon the liquidation, dissolution, bankruptcy or winding-up of the Company or other distribution of its assets among the Shareholders for the purpose of winding-up the Company's affairs.

Awards (entitling the holder thereof to receive Common Shares) have been issued under the Vermilion Incentive Plan. See note 2 regarding equity compensation plans in Vermilion's annual financial statements as at and for the year ended December 31, 2016 (a copy of which is available on SEDAR at www.sedar.com under Vermilion's SEDAR profile) for further details regarding the amount and value of such awards.

Cash Dividends

The Company currently pays dividends on a monthly basis. All decisions with respect to the declaration of dividends on the common shares will be made by the board on the basis of the Company's net earnings, financial requirements and other conditions existing at such future time, planned acquisitions, income tax payable by the Company, crude oil and natural gas prices and access to capital markets, as well as the satisfaction of solvency tests imposed by the ABCA on corporations for the declaration and payment of dividends. It is expected that the dividends will be "eligible dividends" for income tax purposes and thus qualify for the enhanced gross-up and tax credit regime for certain Shareholders.

Record of Cash Dividends

The following table sets forth the amount of cash distributions per Unit for the specified periods declared by the Trust since the completion of the 2003 Arrangement on January 22, 2003 and the cash dividends per common share for the specified periods declared by the Company since the completion of the Conversion Arrangement on September 1, 2010. Dividends are generally paid on the 15th day of the month following the month of declaration. Until the December 2007 distribution announcement, Vermilion had paid distributions of $0.17 per Trust Unit per month. From the January 2008 payment date and onwards, Vermilion paid distributions of $0.19 per Trust Unit and dividends of $0.19 per common share, in each case per month (as applicable). In January 2013, Vermilion increased its dividend to $0.20 per common share effective for the January 2013 dividend paid in February 2013. In November 2013, Vermilion announced that its board had approved a 7.5% increase in the monthly dividend to $0.215 per common share per month effective for the January 2014 dividend paid in February 2014. The monthly dividend was maintained at $0.215 per common share per month throughout 2015 and 2016.

Period	**Distribution Amount for Period per Trust Unit**
As Vermilion Energy Trust	
2003 – January 22 to December 31	$1.87
2004 – January to December	$2.04
2005 – January to December	$2.04
2006 – January to December	$2.04
2007 – January to December	$2.06
2008 – January to December	$2.28
2009 – January to December	$2.28
2010 – January to September [(1)]	$1.71
Period	**Dividend Amount for Period per Common Share**
As Vermilion Energy Inc.	
2010 – September to December [(1)]	$0.57
2011 – January to December	$2.28
2012 – January to December	$2.28
2013 – January to December	$2.40
2014 – January to December	$2.58
2015 – January to December	$2.58
2016 – January to December	$2.58
2017 – January to February	$0.43
Total cash dividends since January 22, 2003	$32.02

Note:

(1) Total cash dividends paid out in 2010 by Vermilion and the Trust to a holder of a common share who was a former holder of a Trust Unit equals $2.28.

Premium Dividend™ and Dividend Reinvestment Plan

Under the Premium Dividend™ and Dividend Reinvestment Plan (the "Plan"), Eligible Shareholders who elect to participate in the Dividend Reinvestment Component can reinvest their dividends in common shares at a discount to the Average Market Price (with no broker commissions or trading costs), similar to our previous Dividend Reinvestment Plan (Vermilion's Amended and Restated Dividend Reinvestment Plan dated effective September 1, 2010 as amended effective February 27, 2014 (the "Previous DRIP"). The discount to the Average Market Price was 3% during 2016 and effective January 1, 2017 the discount is 2%.

Under the Premium Dividend™ Component, Eligible Shareholders have the option to reinvest their dividends in common shares which are exchanged for a premium cash payment equal to 101.5% of the reinvested dividends. Under the Premium Dividend™ Component, shares are issued at a 3.5% discount to the Average Market Price. The shares are sold at prevailing market prices by the Plan Broker (Canaccord Genuity Corporation), who provides participating Shareholders with a premium cash payment equal to 101.5% of their dividends, while the Plan Broker retains the balance of the discount as its fee.

Eligible Shareholders are not required to participate in the Plan. Eligible Shareholders who have not elected to participate in the Plan will continue to receive their regular cash dividends in the usual manner.

The total cost of equity issuance to Vermilion under the Dividend Reinvestment Component and the Premium Dividend™ Component of the Plan is 2% and 3.5%, respectively, providing Vermilion with access to a low cost source of equity capital. The Premium Dividend™ Component of the plan was implemented as a short-term measure to maintain Vermilion's financial strength during the commodity price downturn which began in mid-2014. Commencing with the October dividend payment, the Company began proration of the Premium Dividend™ Component of the Plan by 25%. Vermilion subsequently increased the proration factor applied to the Premium Dividend™ Component to 50% commencing with the January 2017 dividend payment. In February 2017, the Company announced a further increase in the proration factor to 75% commencing with the April 2017 dividend payment. Subject to unexpected changes in the commodity price outlook, Vermilion intends to discontinue the Premium Dividend™ Component beginning with the July 2017 dividend payment, such that there would be no further equity issuance under this program.

Each component of the Plan, which is explained in greater detail in the complete Plan document available on Vermilion's corporate website at www.vermilionenergy.com (under the heading "Investor Relations" subheading "DRIP"), is subject to eligibility restrictions, applicable withholding taxes, prorating as provided for in the Plan, and other limitations on the availability of common shares to be issued or purchased in certain events. Only Canadian-resident Shareholders may participate in the Premium Dividend™ Component of the Plan. The Dividend Reinvestment Component of the Plan is available to Canadian residents and non-U.S. resident foreign Shareholders who meet certain eligibility criteria as set forth in the complete Plan. U.S. resident Shareholders are not currently permitted to participate in either component of the Plan due to the requirement, under U.S. securities regulations, to maintain a continuous shelf registration for issuance of new equity to U.S. Shareholders. At this time, Vermilion has not put in place the required shelf registration due to the high cost of establishing and maintaining such a shelf registration.

™ denotes trademark of Canaccord Genuity Capital Corporation.

Shareholder Rights Plan

Vermilion has a shareholder rights plan (the "Shareholder Rights Plan") to ensure that, to the extent possible, all Shareholders are treated equally and fairly in connection with any takeover bid for the Company. The Shareholder Rights Plan discourages coercive hostile takeover bids by creating the potential that any Common Shares which may be acquired or held by such a bidder will be significantly diluted. Pursuant to the Shareholder Rights Plan, one right (a "Right") has been issued by the Company in respect of each Common Share that is outstanding prior to the time the Rights separate from the Common Shares (the "Separation Time"). The Separation Time would occur at the time of an unsolicited take-over bid whereby a person acquires or attempts to acquire 20% or more of the Company's Common Shares. Until the Separation Time, the rights are not exercisable or dilutive. The Rights do not change the manner in which Shareholders currently trade their Common Shares and no separate Rights certificates are issued. On or after the Separation Time, each Right would permit the holder, other than 20% acquirer, to purchase Common Shares at a substantial discount to the prevailing market price unless the application of the Rights Plan is waived by the Board of Directors.

Vermilion initially adopted a unitholder rights plan in 2003, which was subsequently renewed and approved by unitholders in 2006 and 2009. In conjunction with the conversion of the Trust to a corporation on September 1, 2010, the Shareholder Rights Plan was approved and subsequently reapproved by Shareholders in 2013 and 2016. The Shareholder Rights Plan must be reapproved at every third annual meeting of Shareholders.

The foregoing summary is qualified in its entirety by reference to the Shareholder Rights Plan Agreement, a copy of which is available on SEDAR at www.sedar.com under Vermilion's SEDAR profile.

MARKET FOR SECURITIES

The outstanding common shares of the Company are listed and posted for trading on the TSX and the NYSE under the symbol VET. The following table sets forth the closing price range and trading volume of the common shares on the TSX for the periods indicated:

2016	High	Low	Close	Volume
January	$38.18	$29.71	$37.46	10,885,419
February	$37.80	$31.56	$36.80	8,931,986
March	$42.69	$36.53	$38.01	9,440,829
April	$44.21	$34.86	$43.15	14,172,944
May	$44.81	$39.92	$43.39	10,202,589
June	$47.34	$39.31	$41.14	11,331,250
July	$44.08	$39.88	$43.50	7,690,280
August	$50.04	$42.11	$47.39	9,611,763
September	$51.25	$45.35	$50.82	9,974,099
October	$55.26	$50.41	$52.60	9,399,239
November	$55.20	$50.83	$54.49	7,402,679
December	$58.98	$54.90	$56.49	6,035,617
2017	**High**	**Low**	**Close**	**Volume**
January	$57.98	$52.79	$53.68	5,456,428

AUDIT COMMITTEE MATTERS

Audit Committee Charter

Vermilion has established an audit committee (the "Audit Committee") to assist the board of directors in carrying out its oversight responsibilities with respect to, among other things, financial reporting, internal controls and the external audit process of the Company. The Audit Committee Terms of Reference are set out in Schedule "D" to this annual information form.

Composition of the Audit Committee

The following table sets forth the name of each current member of the Audit Committee, whether pursuant to applicable securities legislation, such member is considered independent, whether pursuant to applicable securities legislation, such member is considered financially literate and the relevant education and experience of such member.

Name	Independent	Financially Literate	Relevant Education and Experience
Catherine L. Williams (Chair)	Yes	Yes	Ms. Williams has a Bachelor of Arts degree from University of Western Ontario and a Masters in Business Administration from the Queen's University. Ms. Williams brings 31 years of oil and gas industry experience, with an extensive background in finance, mergers and acquisitions, and business management. Ms. Williams is currently the Owner and Managing Director of Options Canada Ltd. (since 2007) and serves as a Board member of Enbridge Inc. (since 2010) and Chairs its Human Resources and Compensation Committee. She was a Board member of Alberta Investment Management Corporation from 2009 to 2014 and Tim Hortons Inc. from 2009 to 2012. From 2003 to 2007, Ms. Williams held the role of Chief Financial Officer for Shell Canada Ltd., prior to which she held various positions with Shell Canada Limited, Shell Europe Oil Products, Shell Canada Oil Products and Shell International (1984 to 2003).
Claudio A. Ghersinich	Yes	Yes	Mr. Ghersinich holds a B.Sc. Civil Engineering degree from the University of Manitoba. Mr. Ghersinich has obtained financial experience and exposure to accounting and financial issues in a role as a founder of Vermilion Resources Ltd. in 1994 and as an audit committee member of other public companies.
Larry J. Macdonald	Yes	Yes	Mr. Macdonald holds a Bachelor of Science degree from the University of Alberta. He has more than 46 years of experience in the oil and gas industry, with an extensive background in leadership, strategy and growth, finance, exploration, corporate relations and marketing. Mr. Macdonald completed the Executive Management Program at the Wharton Business School at the University of Pennsylvania in 1993 and attended a Financial Literacy Course at the Rotman Business School at the University of Toronto in coordination with the Institute of Corporate Directors. Currently, he is the Chairman and Chief Executive Officer (since 2003) of Point Energy Ltd., a private oil and gas exploration company. From 2012 to 2016, he was Chairman of Northpoint Resources. From 2003 to 2006, he was a Managing Director of Northpoint Energy Ltd., and from 2006 to 2013 a director of Sure Energy Inc. Previously, he was the Chairman and Chief Executive Officer of Pointwest Energy Inc. and President and Chief Operating Officer of Anderson Exploration Ltd. He began his career with PanCanadian Petroleum Limited in 1969 (until 1977) and later worked for several exploration firms.
Robert Michaleski	Yes	Yes	Mr. Michaleski holds a Bachelor of Commerce (Honours) degree from the University of Manitoba and is a Chartered Accountant. He has over 30 years of experience in various senior management and executive capacities at Pembina Pipeline Corporation. He was Chief Executive Officer from 2000 to 2013 and also President from 2000 to 2012. He was Vice President and Chief Financial Officer from 1997 to 2000, Vice President of Finance from 1992 to 1997, Controller from 1980 to 1992, and Manager of Internal Audit from 1978 to 1980. He has been a Director of Pembina since 2000, a Director of Essential Energy Services Ltd. since 2012, and a Director of Coril Holdings Ltd. since 2003. He is a member of the Institute of Corporate Directors.

External Audit Service Fees

Prior to the commencement of any work, fees for all audit and non-audit services provided by the Company's auditors must be approved by the Audit Committee.

During the years ended December 31, 2016 and 2015, Deloitte LLP, the auditors of the Company, received the following fees from the Company:

Item	2016	2015
Audit fees (1)	$1,545,495	$1,560,759
Audit-related fees (2)	$18,325	$80,698
Tax fees (3)	$57,614	$55,020

Notes:

(1) Audit fees consisted of professional services rendered by Deloitte LLP for the audit of the Company's financial statements for the years ended December 31, 2016 and 2015.

(2) Audit-related fees billed by Deloitte LLP for assurance and related services that are reasonably related to the performance of the audit or review of Vermilion's financial statements, but which are not included in the audit fees.

(3) Tax fees consist of fees for tax compliance services in various jurisdictions.

CONFLICTS OF INTEREST

The directors and officers of Vermilion are engaged in and will continue to engage in other activities in the oil and natural gas industry and, as a result of these and other activities, the directors and officers of Vermilion may become subject to conflicts of interest. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As at the date hereof, Vermilion is not aware of any existing or potential material conflicts of interest between Vermilion and a director or officer of Vermilion.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or officer of the Company, nor any other insider of the Company, nor their associates or affiliates has or has had, at any time within the three most recently completed financial years ending December 31, 2016, any material interest, direct or indirect, in any transaction or proposed transaction that has materially affected or would materially affect the Company.

LEGAL PROCEEDINGS

The Company is not party to any significant legal proceedings as of February 24, 2017.

MATERIAL CONTRACTS

The Company has not entered into any material contracts outside its normal course of business.

INTERESTS OF EXPERTS

As at the date hereof, principals of GLJ, the independent engineers for the Company, personally disclosed in certificates of qualification that they neither had nor expect to receive any common shares. The principals of GLJ and their employees (as a group) beneficially own less than one percent of any of the Company's securities.

Deloitte LLP is the auditor of the Company and is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Company's common shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of the Company. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this annual information form. Additional risks and uncertainties not currently known to Vermilion that it currently views as immaterial may also materially and adversely affect its business, financial condition and/or results of operations. Shareholders and potential Shareholders should carefully consider the information contained herein and, in particular, the following risk factors.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of proved and probable reserves and future net revenues to be derived therefrom, including many factors beyond the Company's control. The reserve and future net revenue information set forth in this annual information form represents estimates only. The reserves and estimated future net cash flow from the Company's properties have been independently evaluated by GLJ with an effective date of December 31, 2016. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of crude oil and natural gas, operating costs, well abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on prices in use at the date the GLJ Report was prepared, and many of these assumptions are subject to change and are beyond the Company's control. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations, probabilistic methods and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Reserve estimates may require revision based on actual production experience. Such figures have been determined based upon assumed commodity prices and operating costs.

The present value of estimated future net revenue referred to in this annual information form should not be construed as the fair market value of estimated crude oil and natural gas reserves attributable to the Company's properties. The estimated discounted future revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations and taxation.

Uncertainty of Contingent Resource Estimates

Information regarding quantities of contingent resources included in the Appendix to this Annual Information Form are estimates only. References to “contingent resources” do not constitute, and should be distinguished from, references to “reserves”. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of contingent resources. In addition, there are contingencies that prevent resources from being classified as reserves. There is no certainty that it will be commercially viable to produce any portion of the contingent resources due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. Actual results may vary significantly from these estimates and such variances could be material.

Uncertainty of Prospective Resource Estimates

Information regarding quantities of prospective resources included in the Appendix to this Annual Information Form are estimates only. References to “prospective resources” do not constitute, and should be distinguished from, references to “reserves” and “contingent resources”. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of prospective resources. In addition, there are contingencies that prevent resources from being classified as reserves. There is no certainty that it will be commercially viable to produce any portion of the prospective resources. Actual results may vary significantly from these estimates and such variances could be material.

Volatility of Oil and Natural Gas Prices

The Company's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated materially during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions. Any prolonged decline in oil and natural gas prices could have an adverse effect on Vermilion's cash flow which could have the effect of decreasing dividends.

Changes in Legislation

There can be no assurance that income tax laws and government incentive programs relating to the oil and gas industry in Canada and the foreign jurisdictions in which the Company operates, will not be changed in a manner which adversely affects the Company.

The Governments of Alberta and Saskatchewan receive royalties on production of natural resources from lands in which they own the mineral rights. A change in the royalty regime resulting in an increase in royalties would reduce Vermilion's net earnings and could make future capital expenditures or Vermilion's operations uneconomic and could, in the event of a material increase in royalties, make it more difficult to service and repay outstanding debt or impair Vermilion's ability to declare dividends. Any material increase in royalties would also significantly reduce the value of the Company's associated assets.

The Government of Alberta released its Royalty Review Advisory Panel Report on January 29, 2016 ("RRAP"). The RRAP recommendations were accepted, which outlined the implementation of a Modernized Royalty Framework ("MRF") that took effect on January 1, 2017. The MRF includes royalty incentives for the efficient development of conventional crude oil, natural gas, and NGL resources, and no changes to the royalty structure of wells drilled prior to 2017 for a 10-year period from the royalty program's implementation date as they will continue to be governed by the previous Alberta Royalty Framework ("ARF"),. It also includes the replacement of royalty credits/holidays on conventional wells by a revenue minus cost framework with a post-payout royalty rate based on commodity prices, the reduction of royalty rates for mature wells, and a neutral internal rate of return for any given play compared to the ARF. The MRF is not expected to materially impact Vermilion's financial condition.

Government Regulations

Vermilion's operations are governed by many levels of government, including municipal, state, provincial and federal governments in Canada, France, Germany, the Netherlands, Australia, Ireland, Hungary, Croatia, Slovakia and the United States. Vermilion is subject to laws and regulations regarding environment, health and safety issues, lease interests, taxes and royalties, among others. Failure to comply with the applicable laws can result in significant increases in costs, penalties and even losses of operating licences. The regulatory process involved in each of the countries in which Vermilion operates is not uniform and regulatory regimes vary as to complexity, timeliness of access to, and response from, regulatory bodies and other matters specific to each jurisdiction. If regulatory approvals or permits are delayed or not obtained, there can also be delays or abandonment of projects, decreases in production and increases in costs, and Vermilion may not be able to fully execute its strategy. Governments may also amend or create new legislation and regulatory bodies may also amend regulations or impose additional requirements which could result in increased capital, operating and compliance costs.

Competition

Vermilion actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, some of which have significantly greater financial resources than Vermilion. Vermilion's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

Vermilion's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Operational Matters

The operation of oil and gas wells and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to Vermilion and possible liability to regulators and third parties. Vermilion maintains liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected operations, to the extent that such insurance is commercially viable. Vermilion may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities may impair Vermilion's ability to satisfy its debt obligations or declare dividends.

Continuing production from a property, and to some extent the marketing of production, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Vermilion or its subsidiaries to certain properties. Such circumstances could impair Vermilion's ability to satisfy its debt obligations or declare dividends.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to Vermilion, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for such expenses.

Risks and uncertainties associated with weather conditions can shorten the winter drilling season in Canada and can impact the spring and summer drilling programs, potentially resulting in increased costs or reduced production. Western Australia's northwest shelf is subject to seasonal disruptions caused by cyclones. During cyclone season (December to March) the Company may have to reduce production rates as a result of the inability to offload to tankers due to bad weather. Cyclones may also cause production shut-ins due to the evacuation of staff or damage to equipment on the platform.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial, state and federal legislation. A breach of such legislation may result in the imposition of fines, the issuance of clean up orders in respect of Vermilion or its assets, or the loss or suspension of regulatory approvals. Such legislation may be changed to impose higher standards and potentially more costly obligations on Vermilion. There can be no assurance that the Company will be able to satisfy its actual future environmental and reclamation obligations.

Vermilion expects to incur abandonment and reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2016, expenditures beyond normal compliance with environmental regulations were considered to be in the ordinary course of business. Vermilion does not anticipate material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2017.

Vermilion's exploration and production facilities and other operations and activities in North America, Europe and Australia will emit a small amount of greenhouse gasses which may subject Vermilion to legislation regulating emissions of greenhouse gases and which may include a requirement to reduce emissions or emissions intensity from Vermilion's operations and facilities. As such, Vermilion continues to evaluate and monitor regulatory initiatives and overall trends so that it is aware of potential developments that could affect its business and operations. It is possible that future international, national, provincial or state emissions reduction requirements in jurisdictions that Vermilion operates in may require further reductions of emissions or emissions intensity. The direct or indirect costs of complying with emissions regulations may adversely affect the business of Vermilion in North America, Europe and Australia.

The Government of Alberta released its Climate Leadership Plan which impacts all consumers and businesses that contribute to carbon emissions in Alberta. The plan includes imposing carbon pricing that is applied on carbon emissions from heating and transportation fuels across all sectors, which started at $20 per tonne on January 1, 2017 and moving to $30 per tonne on January 1, 2018, the phase-out of coal-fired power generation by 2030, a cap on oil sands emissions production of 100 megatonnes, and a 45 per cent reduction in methane emissions by the oil and gas sector by 2025. Vermilion expects the Climate Leadership Plan to increase the cost of operating its properties located in Alberta and does not currently anticipate material impacts on its results of operations.

In October 2016, the Canadian federal government announced a new Pan-Canadian Pricing on Carbon Pollution strategy (the "Strategy") in response to the Paris Agreement that was ratified by Canada and other nations in October 2016. Under the Strategy, the federal government is proposing a benchmark carbon pricing program that includes, at a minimum, a price on carbon emissions of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne in 2022. The Carbon Strategy also proposes a federal backstop in the event that provincial jurisdictions fail to meet the benchmark. As mentioned above, Alberta has already established a carbon pricing system that was referenced in the federal announcement and therefore, currently, the Strategy is not anticipated to have a material impact on Vermilion's results of operations.

Vermilion was awarded a position on CDP's 2016 Climate "A" List. CDP (formerly Carbon Disclosure Project) is a London-based not-for-profit organization that administers a global environmental disclosure system that assists in the measurement and management of corporate environmental impacts. Only 193 companies globally achieved Climate "A" List recognition in 2016 and Vermilion was one of only five oil and gas companies in the world and the only North American energy company on the 2016 list. Vermilion has voluntarily reported emissions data to CDP for each year since 2012, recognizing the importance of measuring and understanding the Company's environmental impact.

Kyoto Protocol

Australia, Canada, France, Ireland, Germany and the Netherlands are signatories to the United Nations Framework Convention on Climate Change and have all ratified the Kyoto Protocol established thereunder. Australia, France, Ireland, Germany and the Netherlands, as Annex B parties to the Kyoto Protocol, and Ireland, France, Germany and Netherlands as members of the European Union, are required to reduce their nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases. Canada formally withdrew from the Kyoto Protocol in 2012.

Discretionary Nature of Dividends

The declaration and payment (including the amount thereof) of future cash dividends, if any, is subject to the discretion of the board of directors of the Company and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests under the ABCA for the declaration and payment of dividends. Depending on these and other factors considered relevant to the declaration and payment of dividends by the board of directors and management of the Company (some or all of which may be beyond the control of the board of directors and management of the Company), the Company may change its dividend policy from time to time. Any reduction of dividends may adversely affect the market price or value of common shares.

Debt Service

Vermilion may, from time to time, finance a significant portion of its operations through debt. Amounts paid in respect of interest and principal on debt incurred by Vermilion may impair Vermilion's ability to satisfy its other obligations. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment by Vermilion of its debt obligations. Ultimately, this may result in lower levels of cash flow for the Company.

Lenders may be provided with security over substantially all of the assets of Vermilion and its Subsidiaries. If Vermilion becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, a lender may be able to foreclose on or sell the assets of Vermilion and/or its Subsidiaries.

Changes in Income Tax Laws

Income tax laws and administrative policies may be changed in a manner which adversely affects the Company and/or Shareholders.

Depletion of Reserves

The Company has certain unique attributes which differentiate it from other oil and gas industry participants. Dividends paid from cash flow generated in respect of properties, absent commodity price increases or cost effective acquisition and development activities, may decline over time in a manner consistent with declining production from typical crude oil, natural gas and natural gas liquids reserves. Accordingly, absent capital expenditures or acquisitions of additional crude oil and natural gas properties, Vermilion's current production levels and reserves will decline.

Vermilion's future crude oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on Vermilion's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, Vermilion's reserves and production will decline over time as reserves are exploited.

Net Asset Value

The net asset value of the assets of the Company from time to time will vary dependent upon a number of factors beyond the control of management, including crude oil and natural gas prices. The trading prices of the common shares from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than the net asset value of the Company's assets.

Volatility of Market Price of Common Shares

The market price of the common shares may be volatile. The volatility may affect the ability of Shareholders to sell the common shares at an advantageous price. Market price fluctuations in the common shares may be due to the Company’s operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts’ estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under “Forward-Looking Statements” in this annual information form. In addition, the market price for securities in the stock markets, including the TSX and NYSE, has experienced significant price and trading fluctuations in recent years. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market price of the common shares.

Variations in Interest Rates and Foreign Exchange Rates

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, potentially impacting dividends to Shareholders.

In addition, an increase in the exchange rate for the Canadian dollar versus the U.S. dollar would result in the receipt by the Company of fewer Canadian dollars for its production which may affect future dividends. The Company monitors and, when appropriate, uses derivative financial instruments to manage its exposure to currency exchange rate risks. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates may impact future dividends and the future value of the Company's reserves as determined by independent evaluators.

Increase in Operating Costs or Decline in Production Level

An increase in operating costs or a decline in Vermilion's production level could have an adverse effect on Vermilion's cash flow and, therefore, could reduce dividends to Shareholders and affect the market price of the common shares. The level of production may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond Vermilion's control. A significant decline in production could result in materially lower revenues and cash flow and, therefore, could reduce dividends to Shareholders and affect the market price of the common shares.

Acquisition Assumptions

When making acquisitions, Vermilion estimates future performance of the assets to be acquired that may prove to be inaccurate.

Acquired assets are subject to inherent risks associated with predicting the future performance of those assets. Vermilion makes certain estimates and assumptions respecting the economic potential of the assets it acquires which may not be realized over time. As such, assets acquired may not possess the value Vermilion attributed to them, which could adversely impact cash flow.

Failure to Realize Anticipated Benefits of Prior Acquisitions

Vermilion may, from time to time, complete one or more acquisitions for various strategic reasons including to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits, including, among other things, potential cost savings. In order to achieve the benefits of any future acquisitions, Vermilion will be dependent upon its ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Company. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during the process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect Vermilion's ability to achieve the anticipated benefits of such prior acquisitions.

Additional Financing

Vermilion's credit facility and any replacement credit facility may not provide sufficient liquidity. The amounts available under Vermilion's credit facility may not be sufficient for future operations, or Vermilion may not be able to obtain additional financing on attractive economic terms, if at all. Any failure to obtain financing may have a material adverse effect on Vermilion's business, and dividends to Shareholders may be reduced, suspended or eliminated.

To the extent that external sources of capital, including the issuance of additional common shares, become limited or unavailable, Vermilion's ability to make the necessary capital investments to maintain or expand its crude oil and natural gas reserves will be impaired. To the extent the Company is required to use cash flow to finance capital expenditures or property acquisitions, the level of cash available that may be declared payable as dividends will be reduced.

Potential Conflicts of Interest

Circumstances may arise where members of the board of directors or officers of Vermilion are directors or officers of companies which are in competition to the interests of Vermilion. No assurances can be given that opportunities identified by such persons will be provided to Vermilion.

Accounting Adjustments

The presentation of financial information in accordance with IFRS requires that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in Vermilion's consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the consolidated financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and may result in an inability to borrow funds and/or may result in a decline in the common share price.

Lower crude oil and gas prices increase the risk of write-downs of Vermilion's oil and gas property investments. Under IFRS, assets are aggregated into groups known as CGUs for impairment testing. CGUs are reviewed for indicators that the carrying value of the CGU may exceed its recoverable amount. If an indication of impairment exists, the CGU's recoverable amount is then estimated. A CGU's recoverable amount is defined as the higher of the fair value less costs to sell and its value in use. If the carrying amount exceeds its recoverable amount an impairment loss is recorded to net earnings in the period to reduce the carrying value of the CGU to its recoverable amount. While these impairment losses would not affect cash flow, the charge to net earnings could be viewed unfavourably in the market.

Market Accessibility

A decline in Vermilion's ability to market crude oil and natural gas production could have a material adverse effect on its production levels or on the price that Vermilion receives for production which, in turn, could reduce dividends to its Shareholders and the trading price of the common shares.

Vermilion's business depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of crude oil and natural gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect Vermilion's ability to produce and market crude oil and natural gas. If market factors change and inhibit the marketing of Vermilion production, overall production or realized prices may decline, which could reduce dividends to Shareholders.

Cyber Security

Vermilion manages cyber security risk by ensuring appropriate technologies, processes and practices are effectively designed and implemented to help prevent, detect and respond to threats as they emerge and evolve. The primary risks to Vermilion include, loss of data, destruction or corruption of data, compromising of confidential customer or employee information, leaked information, disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage. Vermilion relies upon a complete suite of advanced controls as protection from such attacks including, but not limited to the following:

a) Enterprise class firewall infrastructure, secure network architecture and anti-malware defense systems to protect against network intrusion, malware infection and data loss.
b) Regularly conducted comprehensive third party reviews and vulnerability assessments to ensure that information technology systems are up-to-date and properly configured, to reduce security risks arising from outdated or misconfigured systems and software.
c) Disaster recovery planning, ongoing monitoring of network traffic patterns to identify potential malicious activities or attacks

Incident response processes are in place to isolate and control potential attacks. Data backup and recovery processes are in place to minimize risk of data loss and resulting disruption of business. Through ongoing vigilance and regular employee awareness, Vermilion has not experienced a cyber security event of a material nature. As it is difficult to quantify the significance of such events, cyber attacks such as, security breaches of company, customer, employee, and vendor information, as well as hardware or software corruption, failure or error, telecommunications system failure, service provider error, intentional or unintentional personnel actions, malicious software, attempts to gain unauthorized access to data and other electronic security breaches that could lead to disruptions in systems, unauthorized release of confidential or otherwise protected information and the corruption of data, may in certain circumstances be material and could have an adverse effect on Vermilion's business, financial condition and results of operations. As result of the unpredictability of the timing, nature and scope of disruptions from such attacks, Vermilion could potentially be subject to production downtimes, operational delays, the compromising of confidential or otherwise protected information, destruction or corruption of data, security breaches, other manipulation or improper use of its systems and networks or financial losses, any of which could have a material adverse effect on Vermilion's competitive position, financial condition or results of operations.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com under Vermilion's SEDAR profile. Additional information related to the remuneration and indebtedness of the directors and officers of the Company, and the principal holders of common shares and Rights to purchase common shares and securities authorized for issuance under the Company's equity compensation plans, where applicable, are contained in the information circular of the Company in respect of its most recent annual meeting of Shareholders involving the election of directors. Additional financial information is provided in the Company's audited financial statements and management's discussion and analysis for the year ended December 31, 2016.

APPENDIX A
CONTINGENT RESOURCES

Summary information regarding contingent resources and net present value of future net revenues from contingent resources are set forth below and are derived, in each case, from the GLJ Resources Assessment. The GLJ Resources Assessment was prepared in accordance with COGEH and NI-51-101 by GLJ, an independent qualified reserve evaluator. All contingent resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2016. Contingent resources are in addition to reserves estimated in the GLJ Report.

A range of contingent resources estimates (low, best and high) were prepared by GLJ. See notes 6 to 8 of the tables below for a description of low estimate, best estimate and high estimate.

The GLJ Resources Assessment estimated gross risked contingent resources with a project maturity subclass of "Development Pending" of 120.4 million boe (low estimate) to 309.4 million boe (high estimate), with a best estimate of 198.5 million boe. Contingent resources are in addition to reserves estimated in the GLJ Report.

The GLJ Resources Assessment estimated gross risked contingent resources with a project maturity subclass of "Development Unclarified" of 10.7 million boe (low estimate) to 28.7 million boe (high estimate), with a best estimate of 19.5 million boe.

An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Risked Oil and Gas Contingent Resources as at December 31, 2016 **(1) (2)** ***- Forecast Prices and Costs*** **(3) (4)**

Resources	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE			Unrisked BOE	
Project Maturity Sub-Class	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)	Chance of Dev. (%) [9]	Gross (Mboe)	Net (Mboe)
Contingent (1C) - Low Estimate													
Development Pending[10]													
Australia[11]	-	-	-	-	-	-	-	-	-	-	-	-	-
Canada[12]	13,145	9,681	250,957	226,293	1,455	1,382	19,917	15,769	75,131	63,396	81.9%	91,750	77,305
France[13]	14,152	13,241	969	969	-	-	-	-	14,314	13,403	86.8%	16,486	15,438
Germany[14]	-	-	17,317	15,138	-	-	-	-	2,886	2,523	78.3%	3,686	3,222
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands[15]	-	-	10,336	10,336	-	-	2	2	1,725	1,725	81.4%	2,119	2,119
USA[16]	20,581	17,072	18,952	15,720	-	-	2,627	2,179	26,367	21,871	90.0%	29,296	24,300
Total	47,878	39,994	298,531	268,456	1,455	1,382	22,546	17,950	120,423	102,918	84.0%	143,337	122,384
Contingent (2C) - Best Estimate													
Development Pending[10]													
Australia[11]	2,440	2,440	-	-	-	-	-	-	2,440	2,440	80.0%	3,050	3,050
Canada[12]	25,648	18,373	389,272	346,617	3,534	3,357	29,537	22,869	120,653	99,571	80.3%	150,178	123,661
France[13]	27,543	25,702	1,246	1,246	-	-	-	-	27,751	25,908	85.1%	32,628	30,453
Germany[14]	-	-	29,595	25,886	-	-	-	-	4,933	4,314	78.3%	6,300	5,510
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands[15]	-	-	28,521	28,521	-	-	6	6	4,760	4,760	81.3%	5,853	5,853
USA[16]	29,466	24,441	27,811	23,069	-	-	3,855	3,197	37,956	31,483	90.0%	42,173	34,981
Total	85,097	70,956	476,445	425,339	3,534	3,357	33,398	26,072	198,493	168,476	82.6%	240,182	203,508
Contingent (3C) - High Estimate													
Development Pending[10]													
Australia[11]	3,280	3,280	-	-	-	-	-	-	3,280	3,280	80.0%	4,100	4,100
Canada[12]	52,590	37,459	567,390	500,749	5,174	4,788	41,650	31,616	189,667	153,331	79.2%	239,562	193,233
France[13]	43,866	40,873	1,609	1,609	-	-	-	-	44,134	41,141	84.3%	52,336	48,774
Germany[14]	-	-	54,150	47,382	-	-	-	-	9,025	7,897	78.3%	11,526	10,086
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands[15]	-	-	50,159	50,159	-	-	13	13	8,373	8,373	80.5%	10,403	10,403
USA[16]	42,381	35,152	40,945	33,961	-	-	5,675	4,707	54,880	45,519	90.0%	60,977	50,577
Total	142,117	116,764	714,253	633,860	5,174	4,788	47,338	36,336	309,359	259,541	81.6%	378,904	317,173

Resources	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE			Unrisked BOE	
Project Maturity Sub-Class	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)	Chance of Dev. (%) [9]	Gross (Mboe)	Net (Mboe)
Contingent (1C) - Low Estimate Development Unclarified[17]													
Australia	-	-	-	-	-	-	-	-	-	-	-	-	-
Canada[18]	-	-	44,744	39,976	-	-	897	745	8,354	7,408	58.2%	14,361	12,743
France[19]	1,511	1,434	-	-	-	-	-	-	1,511	1,434	42.4%	3,560	3,376
Germany	-	-	-	-	-	-	-	-	-	-	-	-	-
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands	-	-	-	-	-	-	-	-	-	-	-	-	-
USA	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1,511	1,434	44,744	39,976	-	-	897	745	9,865	8,842	55.0%	17,921	16,119
Contingent (2C) - Best Estimate Development Unclarified[17]													
Australia	-	-	-	-	-	-	-	-	-	-	-	-	-
Canada[18]	-	-	75,428	66,726	-	-	1,640	1,339	14,211	12,460	57.2%	24,859	21,796
France[19]	2,539	2,410	-	-	-	-	-	-	2,539	2,410	44.6%	5,690	5,398
Germany	-	-	-	-	-	-	-	-	-	-	-	-	-
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands[20]	-	-	16,351	15,777	-	-	32	16	2,757	2,646	49.4%	5,580	5,301
USA	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,539	2,410	91,779	82,503	-	-	1,672	1,355	19,507	17,516	54.0%	36,129	32,495
Contingent (3C) - High Estimate Development Unclarified[17]													
Australia	-	-	-	-	-	-	-	-	-	-	-	-	-
Canada[18]	-	-	103,491	89,867	-	-	2,178	1,727	19,427	16,705	57.6%	33,746	29,063
France[19]	3,825	3,632	-	-	-	-	-	-	3,825	3,632	46.4%	8,250	7,829
Germany	-	-	-	-	-	-	-	-	-	-	-	-	-
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands[20]	-	-	32,346	31,475	-	-	48	24	5,439	5,270	53.4%	10,184	9,761
USA	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	3,825	3,632	135,837	121,342	-	-	2,226	1,751	28,691	25,607	55.0%	52,180	46,653

Summary of Risked Net Present Value of Future Net Revenues as at December 31, 2016 - Forecast Prices and Costs [3]

Resources Project Maturity Sub-Class	Before Income Taxes, Discounted at [5]					After Income Taxes, Discounted at [5]				
(M$)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Contingent (1C) - Low Estimate [6]										
Development Pending [10]										
Australia[11]	-	-	-	-	-	-	-	-	-	-
Canada[12]	1,469,731	806,673	468,784	284,859	179,205	567,431	315,876	182,036	107,244	107,244
France[13]	819,095	435,463	247,355	146,903	90,157	582,296	295,394	158,897	88,278	49,769
Germany[14]	29,787	19,161	11,552	6,390	2,959	20,027	11,662	5,658	1,665	(894)
Ireland	-	-	-	-	-	-	-	-	-	-
Netherlands[15]	51,663	37,509	28,134	21,720	17,177	27,656	19,744	14,440	10,833	8,313
USA[16]	875,320	424,777	223,556	125,266	73,505	562,210	269,146	138,253	74,966	42,140
Total	3,245,596	1,723,583	979,381	585,138	363,003	2,261,816	1,163,377	633,124	357,778	206,572
Contingent (2C) - Best Estimate [7]										
Development Pending [10]										
Australia[11]	102,151	60,643	36,438	22,134	13,559	26,695	12,642	5,228	1,407	(483)
Canada[12]	2,749,285	1,453,434	840,871	519,322	337,021	2,003,094	1,033,233	579,568	345,415	215,410
France[13]	1,730,450	899,321	508,686	305,273	191,641	1,230,218	615,216	334,091	191,820	114,668
Germany[14]	103,451	71,870	50,479	35,968	25,990	74,526	50,615	34,375	23,449	16,048
Ireland	-	-	-	-	-	-	-	-	-	-
Netherlands[15]	160,324	110,209	79,494	59,475	45,757	86,998	58,171	40,486	29,074	21,367
USA[16]	1,561,749	736,050	390,965	226,282	139,356	1,007,434	471,250	247,014	140,765	85,218
Total	6,407,410	3,331,527	1,906,933	1,168,454	753,324	4,428,965	2,241,127	1,240,762	731,930	452,228
Contingent (3C) - High Estimate [8]										
Development Pending [10]										
Australia[11]	190,589	116,134	72,383	46,105	29,966	63,277	36,147	20,606	11,695	6,558
Canada[12]	5,020,914	2,498,830	1,392,053	837,248	532,137	3,660,740	1,782,927	966,824	563,961	346,457
France[13]	2,954,319	1,525,736	866,518	524,651	332,885	2,100,039	1,051,087	577,537	337,293	205,471
Germany[14]	252,820	174,810	124,211	90,601	67,647	184,908	126,647	88,732	63,652	46,653
Ireland	-	-	-	-	-	-	-	-	-	-
Netherlands[15]	315,718	211,894	151,407	113,180	87,473	171,705	113,248	79,106	57,702	43,468
USA[16]	2,640,857	1,172,989	614,674	358,063	224,065	1,708,970	754,738	392,026	226,212	140,202
Total	11,375,217	5,700,393	3,221,246	1,969,848	1,274,173	7,889,639	3,864,794	2,124,831	1,260,515	788,809
Contingent (1C) - Low Estimate [6]										
Development Unclarified [17]										
Australia	-	-	-	-	-	-	-	-	-	-
Canada[18]	81,186	32,743	13,139	4,876	1,294	58,404	22,305	7,967	2,138	(237)
France[19]	109,246	56,246	30,550	17,349	10,224	77,091	38,798	20,522	11,315	6,453
Germany	-	-	-	-	-	-	-	-	-	-
Ireland	-	-	-	-	-	-	-	-	-	-
Netherlands[20]	-	-	-	-	-	-	-	-	-	-
USA	-	-	-	-	-	-	-	-	-	-
Total	190,432	88,989	43,689	22,225	11,518	135,495	61,103	28,489	13,453	6,216
Contingent (2C) - Best Estimate [7]										
Development Unclarified [17]										
Australia	-	-	-	-	-	-	-	-	-	-
Canada[18]	149,050	60,346	25,047	10,046	3,342	107,851	41,837	15,842	5,073	466
France[19]	198,194	95,437	49,664	27,439	15,881	140,218	66,266	33,693	18,135	10,199
Germany	-	-	-	-	-	-	-	-	-	-
Ireland	-	-	-	-	-	-	-	-	-	-
Netherlands[20]	63,974	35,129	18,879	9,435	3,747	34,153	16,587	6,654	985	(2,320)
USA	-	-	-	-	-	-	-	-	-	-
Total	411,218	190,912	93,590	46,920	22,970	282,222	124,690	56,189	24,193	8,345
Contingent (3C) - High Estimate [8]										
Development Unclarified [17]										
Australia	-	-	-	-	-	-	-	-	-	-
Canada[18]	250,258	97,428	41,153	18,033	7,732	181,844	68,851	27,516	10,840	3,628
France[19]	320,784	143,786	72,178	39,161	22,464	227,214	100,294	49,348	26,186	14,667
Germany	-	-	-	-	-	-	-	-	-	-
Ireland	-	-	-	-	-	-	-	-	-	-
Netherlands[20]	176,750	94,921	54,922	33,238	20,539	96,181	48,927	25,901	13,615	6,587
USA	-	-	-	-	-	-	-	-	-	-
Total	747,792	336,135	168,253	90,432	50,735	505,239	218,072	102,765	50,641	24,882

Notes:

(1) Contingent resources are defined in the COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that Vermilion will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. The risked net present value of the future net revenue from the contingent resources does not represent the fair market value of the contingent resources. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

(2) GLJ prepared the estimates of contingent resources shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

(3) The forecast price and cost assumptions utilized in the year-end 2016 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See ”GLJ December 31, 2016 Forecast Prices” in this AIF.

(4) "Gross” contingent resources are Vermilion's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Vermilion. "Net” contingent resources are Vermilion's working interest (operating or non-operating) share after deduction of royalty obligations, plus Vermilion's royalty interests in contingent resources.

(5) The risked net present value of future net revenue attributable to the contingent resources does not represent the fair market value of the contingent resources. Estimated abandonment and reclamation costs have been included in the evaluation.

(6) This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

(7) This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

(8) This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(9) The Chance of Development (CoDev) is the estimated probability that, once discovered, a known accumulation will be commercially developed. Five factors have been considered in determining the CoDev as follows:

- CoDev = Ps (Economic Factor) × Ps (Technology Factor) × Ps (Development Plan Factor) ×Ps (Development Timeframe Factor) × Ps (Other Contingency Factor) wherein
- Ps is the probability of success
- Economic Factor – For reserves to be assessed, a project must be economic. With respect to contingent resources, this factor captures uncertainty in the assessment of economic status principally due to uncertainty in cost estimates and marketing options. Economic viability uncertainty due to technology is more aptly captured with the Technology Factor. The Economic Factor will be 1 for reserves and will often be 1 for development pending projects and for projects with a development study or pre-development study with a robust rate of return. A robust rate of return means that the project retains economic status with variation in costs and/or marketing plans over the expected range of outcomes for these variables.
- Technology Factor - For reserves to be assessed, a project must utilize established technology. With respect to contingent resources, this factor captures the uncertainty in the viability of the proposed technology for the subject reservoir, namely, the uncertainty associated with technology under development. By definition, technology under development is a recovery process or process improvement that has been determined to be technically viable via field test and is being field tested further to determine its economic viability in the subject reservoir. The Technology Factor will be 1 for reserves and for established technology. For technology under development, this factor will consider different risks associated with technologies being developed at the scale of the well versus the scale of a project and technologies which are being modified or extended for the subject reservoir versus new emerging technologies which have not previously been applied in any commercial application. The risk assessment will also consider the quality and sufficiency of the test data available, the ability to reliably scale such data and the ability to extrapolate results in time.
- Development Plan Factor – For reserves to be assessed, a project must have a detailed development plan. With respect to contingent resources, this factor captures the uncertainty in the project evaluation scenario. The Development Plan Factor will be 1 for reserves and high, approaching 1, for development pending projects. This factor will consider development plan detail variations including the degree of delineation, reservoir specific development and operating strategy detail (technology decision, well layouts (spacing and pad locations), completion strategy, start-up strategy, water source and disposal, other infrastructure, facility design, marketing plans etc) and the quality of the cost estimates as provided by the developer.
- Development Timeframe Factor – In the case of major projects, for reserves to be assessed, first major capital spending must be initiated within 5 years of the effective date. The Development Timeframe Factor will be 1 for reserves and will often be 1 for development pending projects provided the project is planned on-stream based on the same criteria used in the assessment of reserves. With respect to contingent resources, the factor will approach 1 for projects planned on-stream with a timeframe slightly longer than the limiting reserves criteria.
- Other Contingency Factor – For reserves to be assessed, all contingencies must be eliminated. With respect to contingent resources, this factor captures major contingencies, usually beyond the control of the operator, other than those captured by economic status, technology status, project evaluation scenario status and the development timeframe. The Other Contingency Factor will be 1 for reserves and for development pending projects and less than 1 for on hold. Provided all contingencies have been identified and their resolution is reasonably certain, this factor would also be 1 for development unclarified projects.
- These factors may be inter-related (dependent) and care has been taken to ensure that risks are appropriately accounted.

(10) Project maturity subclass development pending is defined as contingent resources where resolution of the final conditions for development is being actively pursued (high chance of development).

(11) Contingent resources for Australia have been estimated based on the continued drilling in our active core asset (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these contingent resources on commercial production is $142 MM and the expected timeline is between 7 and 9 years. The specific contingencies for these resources are corporate commitment and development timing.

(12) Contingent resources for Canada have been estimated based on the continued drilling in our active core assets (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these contingent resources on commercial production is $1,170 MM and the expected timeline is between 1 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(13) Contingent resources for France have been estimated based on the continued drilling in our active core assets (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these contingent resources on commercial production is $550 MM and the expected timeline is between 3and 10 years. The specific contingencies for these resources are corporate commitment and development timing.

(14) Contingent resources for Germany have been estimated based on the continued drilling in our active core assets (see “Description of Properties” section of this AIF) using established recovery technologies. The estimated cost to bring these contingent resources on commercial production is $55 MM and the expected timeline is between 3 and 5 years. The specific contingencies for these resources are corporate commitment and development timing.

(15) Contingent resources for Netherlands have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The estimated cost to bring these contingent resources on commercial production is $34 MM and the expected timeline is between two and 10 years. The specific contingencies for these resources are corporate commitment and development timing.

(16) Contingent resources for USA have been estimated based on the continued drilling in our active core asset (see "Description of Properties" section of this AIF) using established recovery technologies. The estimated cost to bring these contingent resources on commercial production is $431 MM and the expected timeline is between 4 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(17) Project maturity subclass development unclarified is defined as contingent resources when the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties.

(18) In Canada, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 14.2 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $108 MM with an expected timeline of 4 to 15 years.

Ferrier Notikewin	Based on contingencies related to corporate commitment and development timing that is greater than 10 years, GLJ has estimated risked unclarified best estimate contingent resources at 5.1 mmboe and the risked estimated cost to bring these resources on commercial production is $36 MM. The expected timeline is 11 to 15 years.
Ferrier Falher	Based on contingencies related to corporate commitment and development timing that is greater than 10 years, GLJ has estimated risked unclarified best estimate contingent resources at 3.8 mmboe and the risked estimated cost to bring these resources on commercial production is $28 MM. The expected timeline is 11 to 15 years.
West Pembina Glauconite	Based on contingencies related to corporate commitment and development timing as well as economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands, GLJ has estimated risked unclarified best estimate contingent resources at 5.3 mmboe and the risked estimated cost to bring these resources on commercial production is $44 MM. The expected timeline is 4 to 10 years.

(19) In France, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 2.5 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $36 MM with an expected timeline of 8 to 10 years.

Charmottes	Based on contingencies related to corporate commitment and development timing, along with the project still being in the pre-development study/sourcing stage related to waterflood development, GLJ has estimated risked unclarified best estimate contingent resources at 1.3 mmboe and the risked estimated cost to bring these resources on commercial production is $29 MM. The expected timeline is 8 to 10 years.
Chaunoy	Based on contingencies related to corporate commitment and development timing, along with a CO2 pilot project still being in the conceptual study stage, GLJ has estimated risked unclarified best estimate contingent resources at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM. The expected timeline is 9 to 10 years.

(20) In the Netherlands, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 2.8 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated to bring these resources on commercial production an aggregate of $45 MM with an expected timeline of 3 to 9 years.

Netherlands East	Based on contingencies related to corporate commitment and development timing along with proof-of-concept utilizing directional drilling and unknown deliverability from Zechstein carbonates, GLJ has estimated risked unclarified best estimate contingent resources at 1.6 mmboe and the risked estimated cost to bring these resources on commercial production is $24 MM. The expected timeline is 3 to 9 years.
Netherlands West	Based on contingencies related to corporate commitment and development timing along with further study required regarding the deliverability of the Bunter sands, GLJ has estimated risked unclarified best estimate contingent resources at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $21 MM. The expected timeline is 5 years.

PROSPECTIVE RESOURCES

Summary information regarding prospective resources and net present value of future net revenues from prospective resources are set forth below and are derived, in each case, from the GLJ Resources Assessment. The GLJ Resources Assessment was prepared in accordance with COGEH and NI-51-101 by GLJ, an independent qualified reserve evaluator. All prospective resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2016. Prospective resources are in addition to reserves estimated in the GLJ Report.

A range of prospective resources estimates (low, best and high) were prepared by GLJ. See notes 6 to 8 of the tables below for a description of low estimate, best estimate and high estimate.

The GLJ Resources Assessment estimated gross risked prospective resources of 45.2 million boe (low estimate) to 147.9 million boe (high estimate), with a best estimate of 89.5 million boe.

An estimate of risked net present value of future net revenue of prospective resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes prospective resources that are considered too uncertain with respect to the chance of development and chance of discovery to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Risked Oil and Gas Prospective Resources as at December 31, 2016 **(1) (2)** ***- Forecast Prices and Costs*** **(3) (4)**

Resources	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE			Unrisked BOE	
Project Maturity Sub-Class	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)	Chance of Commerciality (%) (9)	Gross (Mboe)	Net (Mboe)
Prospective - Low Estimate Prospect(10)													
Australia(11)	-	-	-	-	-	-	-	-	-	-	-	-	-
Canada(12)	185	166	95,116	87,039	-	-	5,458	4,703	21,496	19,376	32.9%	65,396	58,986
France(13)	3,379	3,044	-	-	-	-	-	-	3,379	3,044	49.0%	6,898	6,253
Germany(14)	-	-	88,561	76,691	-	-	-	-	14,760	12,782	24.6%	59,995	51,954
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands(15)	-	-	33,037	31,606	-	-	16	14	5,522	5,282	11.6%	47,452	45,232
USA	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	3,564	3,210	216,714	195,336	-	-	5,474	4,717	45,157	40,484	25.1%	179,741	162,425
Prospective - Best Estimate Prospect(10)													
Australia(11)	579	579	-	-	-	-	-	-	579	579	48.0%	1,207	1,027
Canada(12)	2,263	2,029	170,797	153,565	-	-	10,195	8,412	40,924	36,035	34.3%	119,269	105,029
France(13)	9,609	8,532	-	-	-	-	-	-	9,609	8,532	37.2%	25,835	22,939
Germany(14)	-	-	169,557	147,917	-	-	-	-	28,260	24,653	24.6%	114,865	100,205
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands(15)	-	-	60,647	57,618	-	-	30	27	10,138	9,630	11.8%	85,890	81,192
USA	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	12,451	11,140	401,001	359,100	-	-	10,225	8,439	89,510	79,429	25.8%	347,066	310,392
Prospective - High Estimate Prospect(10)													
Australia(11)	1,462	1,462	-	-	-	-	-	-	1,462	1,462	48.0%	3,046	3,046
Canada(12)	2,394	2,142	244,013	217,049	-	-	14,659	11,724	57,722	50,041	35.6%	162,333	140,646
France(13)	21,406	19,496	-	-	-	-	-	-	21,406	19,496	48.4%	44,243	40,766
Germany(14)	-	-	289,626	254,136	-	-	-	-	48,271	42,356	24.6%	196,205	172,162
Ireland	-	-	-	-	-	-	-	-	-	-	-	-	-
Netherlands(15)	-	-	114,102	106,974	-	-	59	52	19,076	17,881	11.9%	159,744	148,690
USA	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	25,262	23,100	647,741	578,159	-	-	14,718	11,776	147,937	131,236	26.2%	565,571	505,310

Summary of Risked Net Present Value of Future Net Revenues as at December 31, 2016 - Forecast Prices and Costs [3]

Resources Project Maturity Sub-Class	Before Income Taxes, Discounted at [5]					After Income Taxes, Discounted at [5]				
(M$)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**
Prospective (Pr1) -Low Estimate [6]										
Prospect [10]										
Canada [12]	273,867	127,001	60,110	27,921	11,751	198,318	85,907	35,748	12,466	1,407
France [13]	151,213	75,323	38,554	20,217	10,789	102,347	48,093	22,638	10,518	4,652
Germany [14]	155,230	65,643	24,054	5,229	(3,139)	106,234	38,604	8,125	(4,675)	(9,585)
Netherlands [15]	146,420	81,758	50,537	34,384	25,278	75,803	39,394	21,746	13,088	8,573
Total	726,730	349,725	173,255	87,751	44,679	482,702	211,998	88,257	31,397	5,047
Prospective (Pr2) -Best Estimate [7]										
Prospect [10]										
Australia [11]	46,694	25,575	14,527	8,526	5,152	18,252	9,659	5,268	2,957	1,705
Canada [12]	727,622	350,852	183,676	102,149	59,257	528,484	248,071	122,227	63,175	33,061
France [13]	517,189	263,016	143,095	82,612	50,242	362,550	176,276	91,520	50,373	29,196
Germany [14]	572,696	240,171	105,603	47,332	20,454	415,985	166,082	66,349	24,697	6,525
Netherlands [15]	364,314	193,047	120,340	83,689	62,715	195,684	99,659	59,140	39,348	28,449
Total	2,228,515	1,072,661	567,241	324,308	197,820	1,520,955	699,747	344,504	180,550	98,936
Prospective (Pr3) -High Estimate [8]										
Prospect [10]										
Australia [11]	150,518	78,083	43,242	25,161	15,218	62,445	31,968	17,425	9,981	5,947
Canada [12]	1,110,298	500,889	256,708	143,539	85,330	808,440	354,301	174,070	92,184	51,196
France [13]	1,550,119	742,476	388,981	219,441	131,689	1,098,279	514,614	263,597	145,437	85,435
Germany [14]	1,215,756	520,750	240,583	116,696	57,872	897,478	370,617	162,227	72,477	31,319
Netherlands [15]	785,423	409,343	255,631	178,273	133,629	425,214	216,893	132,001	90,034	66,319
Total	4,812,114	2,251,541	1,185,145	683,110	423,738	3,291,856	1,488,393	749,320	410,113	240,216

Notes:

(1) Prospective resources are defined in the COGEH as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from unknown accumulations by application of future development projects. Prospective resources have both an associated chance of discovery (CoDis) and a chance of development (CoDev). There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources or that Vermilion will produce any portion of the volumes currently classified as prospective resources. The estimates of prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated, as at a given date, and that the resources can be profitably produced in the future. The risked net present value of the future net revenue from the prospective resources does not represent the fair market value of the prospective resources. Actual prospective resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

(2) GLJ prepared the estimates of prospective resources shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table.

(3) The forecast price and cost assumptions utilized in the year-end 2016 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See ”GLJ December 31, 2016 Forecast Prices” in this AIF.

(4) "Gross” prospective resources are Vermilion's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Vermilion. "Net” prospective resources are Vermilion's working interest (operating or non-operating) share after deduction of royalty obligations, plus Vermilion's royalty interests in prospective resources.

(5) The risked net present value of future net revenue attributable to the prospective resources does not represent the fair market value of the prospective resources. Estimated abandonment and reclamation costs have been included in the evaluation.

(6) This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

(7) This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

(8) This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

(9) The chance of commerciality is defined as the product of the chance of discovery and the chance of development. Chance of discovery is defined in COGEH as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. Chance of development is defined as the estimated probability that, once discovered, a known accumulation will be commercially developed.

The Chance of Development (CoDev) is the estimated probability that, once discovered, a known accumulation will be commercially developed. Five factors have been considered in determining the CoDev as follows:

- CoDev = Ps (Economic Factor) × Ps (Technology Factor) × Ps (Development Plan Factor) ×Ps (Development Timeframe Factor) × Ps (Other Contingency Factor) wherein
- Ps is the probability of success

- Economic Factor – For reserves to be assessed, a project must be economic. With respect to prospective resources, this factor captures uncertainty in the assessment of economic status principally due to uncertainty in cost estimates and marketing options. Economic viability uncertainty due to technology is more aptly captured with the Technology Factor. The Economic Factor will be 1 for reserves and will often be 1 for development pending and for projects with a development study or pre-development study with a robust rate of return. A robust rate of return means that the project retains economic status with variation in costs and/or marketing plans over the expected range of outcomes for these variables.
- Technology Factor - For reserves to be assessed, a project must utilize established technology. With respect to prospective resources, this factor captures the uncertainty in the viability of the proposed technology for the subject reservoir, namely, the uncertainty associated with technology under development. By definition, technology under development is a recovery process or process improvement that has been determined to be technically viable via field test and is being field tested further to determine its economic viability in the subject reservoir. The Technology Factor will be 1 for reserves and for established technology. For technology under development, this factor will consider different risks associated with technologies being developed at the scale of the well versus the scale of a project and technologies which are being modified or extended for the subject reservoir versus new emerging technologies which have not previously been applied in any commercial application. The risk assessment will also consider the quality and sufficiency of the test data available, the ability to reliably scale such data and the ability to extrapolate results in time.
- Development Plan Factor – For reserves to be assessed, a project must have a detailed development plan. With respect to prospective resources, this factor captures the uncertainty in the project evaluation scenario. The Development Plan Factor will be 1 for reserves and high, approaching 1, for development pending projects. This factor will consider development plan detail variations including the degree of delineation, reservoir specific development and operating strategy detail (technology decision, well layouts (spacing and pad locations), completion strategy, start-up strategy, water source and disposal, other infrastructure, facility design, marketing plans etc.) and the quality of the cost estimates as provided by the developer.
- Development Timeframe Factor – In the case of major projects, for reserves to be assessed, first major capital spending must be initiated within 5 years of the effective date. The Development Timeframe Factor will be 1 for reserves and will often be 1 for development pending provided the project is planned on-stream based on the same criteria used in the assessment of reserves. With respect to prospective resources, the factor will approach 1 for projects planned on-stream with a timeframe slightly longer than the limiting reserves criteria.
- Other Contingency Factor – For reserves to be assessed, all contingencies must be eliminated. With respect to prospective resources, this factor captures major contingencies, usually beyond the control of the operator, other than those captured by economic status, technology status, project evaluation scenario status and the development timeframe. The Other Contingency Factor will be 1 for reserves and for development pending and less than 1 for on hold. Provided all contingencies have been identified and their resolution is reasonably certain, this factor would also be 1 for development unclarified.
- These factors may be inter-related (dependent) and care has been taken to ensure that risks are appropriately accounted.

The Chance of Discovery (CoDis) is defined in COGEH as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. Five factors have been considered in determining the CoDis as follows:

- CoDis = Ps (Source) × Ps (Timing and Migration) × Ps (Trap) ×Ps (Seal) × Ps (Reservoir) wherein
- Ps is the probability of success
- Source – For a significant accumulation of potentially recoverable petroleum, a viable source rock capable of generating hydrocarbons must exist. The probability of a source rock investigates stratigraphic presence and location, volumetric adequacy and organic richness of the proposed source rock. In proven hydrocarbon systems, this factor will be a 1. This factor becomes critical when looking at frontier basins.
- Timing and Migration - For a significant accumulation of potentially recoverable petroleum, the source rock must reach thermal maturity to generate the hydrocarbons and have a conduit with which to fill the closures that existed at the time of migration. The probability of timing and migration investigates the movement of hydrocarbons from the source rock to the trap. This factor evaluates the pathways and/or carrier beds, including fault systems, which can transport buoyant hydrocarbons from the source kitchen to the prospect area at a time that the trap existed. This factor is often 1 in producing trends, but there is a possibility of migration shadows where the conduits do not fill a viable trap, which would decrease this factor.
- Trap - For a significant accumulation of potentially recoverable petroleum, a reservoir must be present in a structural or stratigraphic closure. The trap factor looks at the definition of the geometry of the accumulation, which is determined using seismic, gravity and/or magnetic techniques and surrounding well logs to determine the probability of a significant accumulation. The risking of this includes examining data quality (e.g. 2D vs 3D seismic coverage) and potential depth conversion possibilities which give confidence in the mapped trap. Stratigraphic trap definition is used for volumetric calculations, but it is given a 1 for this chance factor as the stratigraphic risk will be captured in seal.
- Seal - For a significant accumulation of potentially recoverable petroleum, a reservoir must be sealed both on the top and laterally by a lithology that contains the hydrocarbon accumulation within the reservoir. It is also necessary that these accumulated hydrocarbons have been preserved from flushing or leakage. Factors that affect top, seat and lateral seals are fluid viscosity, bed thickness, natural continuity of sealing facies, differential permeability, fault history and reservoir pressures needed to maintain a hydrocarbon column. The probability that the accumulation is not able to be contained by the surrounding rocks is captured in this chance factor.
- Reservoir - For a significant accumulation of potentially recoverable petroleum, a reservoir rock must be present and have sufficient porosity and permeability and be of a sufficient thickness to produce quantities of mobile hydrocarbon. Under this approach, encountering wet, commercial quality and quantity sandstones would not be a failure in the reservoir category, but rather in one of the other factors. It is the reservoir along with the trap which determine the volumetrics of the accumulation.
- Serial multiplication of these five decimal fractions representing the five geologic chance factors can be done as they are considered independent of each other.

(10) GLJ has sub-classified the best estimate prospective resources by maturity status, consistent with the requirements of the COGE Handbook. These prospective resources have been sub-classified as “Prospect” which the COGE Handbook defines as a potential accumulation within a play that is sufficiently well defined to present a viable drilling target.

(11) Prospective resources for Australia have been estimated based on development timing and reservoir risk, GLJ has estimated the CoDev at 80% and the CoDis at 60%. The corresponding chance of commerciality is 48%. Risked best estimate prospective resources have been estimated at .06 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is $17.2 MM. The expected development timeline is 8 years.

(12) Prospective resources for Canada have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 86% and the aggregate CoDis at 40%. The corresponding chance of commerciality is 34%. Risked best estimate prospective resources have been estimated at an aggregate of 40.9 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $621.9 MM. The expected development timeline is 2 to 20 years.

Wilrich Prospect:	Based on reservoir risk, development timing and limited Wilrich development on the land base, GLJ has estimated the CoDev at 35% and the CoDis at 85%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 22.2 mmboe and the risked estimated cost to bring these resources on commercial production is $218 MM with an expected timeline of 2 to 8 years.
West Pembina Glauconite Prospect:	Based on chance of discovery risk due to uncertainty regarding threshold for reservoir quality to support commercial development of resources with horizontal drilling, along with economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands and chance of development risk related to corporate commitment and development timing. GLJ has estimated the CoDev at 34% and the CoDis at 90%. The corresponding chance of commerciality is 31%. Risked best estimate prospective resources have been estimated at 8.4 mmboe and the risked estimated cost to bring these resources on commercial production is $242 MM with an expected timeline of 6 to 14 years.

Drayton Valley Notikewin Prospect:	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 85%. The corresponding chance of commerciality is 60%. Risked best estimate prospective resources have been estimated at 4.6 mmboe and the risked estimated cost to bring these resources on commercial production is $69.3 MM. The expected development timeline is 10 to 12 years.
Saskatchewan Prospects	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 90% and the CoDis at 80%. The corresponding chance of commerciality is 72%. Risked best estimate prospective resources have been estimated at 3.0 mmboe and the risked estimated cost to bring these resources on commercial production is $63.6 MM with an expected timeline of 7 to 12 years
Ferrier Falher Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 90%. The corresponding chance of commerciality is 54%. Risked best estimate prospective resources have been estimated at 2.6 mmboe and the risked estimated cost to bring these resources on commercial production is $24.9 MM with an expected timeline of 16 to 20 years.
Utikuma Gilwood Prospect	Based on reservoir risk, development timing and limited Gilwood development in the area, GLJ has estimated the CoDev at 60% and the CoDis at 50%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $3.2 MM with an expected timeline of 16 to 20 years.

(13) Prospective resources for France have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 52% and the aggregate CoDis at 71%. The corresponding chance of commerciality is 37%. Risked best estimate prospective resources have been estimated at an aggregate of 9.6 Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $254.3 MM. The expected development timeline is 3 to 12 years.

Rachee Prospect	Based on risk of closure and data quality along with development timing, GLJ has estimated the CoDev at 80% and the CoDis at 80%. The corresponding chance of commerciality is 64%. Risked best estimate prospective resources have been estimated at 3.4 mmboe and the risked estimated cost to bring these resources on commercial production is $125.0 MM with an expected timeline of 10 to 14 years.
Malnoue Prospect	Based on reservoir, structure and trap risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 38%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $31.6 MM with an expected timeline of 8 to 12 years.
West Lavergne Prospect	Based on structure risk and development timing GLJ has estimated the CoDev at 80% and the CoDis at 70%. The corresponding chance of commerciality is 56%. Risked best estimate prospective resources have been estimated at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $6.1 MM with an expected timeline of 4 years.
Champotran Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 80% and the CoDis at 80%. The corresponding chance of commerciality is 64%. Risked best estimate prospective resources have been estimated at 0.7 mmboe and the risked estimated cost to bring these resources on commercial production is $14.6 MM with an expected timeline of 7 to 8 years.
Cazaux Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 30%. The corresponding chance of commerciality is 21%. Risked best estimate prospective resources have been estimated at 0.6 mmboe and the risked estimated cost to bring these resources on commercial production is $10.3 MM with an expected timeline of 5 to 7 years.
Vulaines Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 80% and the CoDis at 40%. The corresponding chance of commerciality is 32%. Risked best estimate prospective resources have been estimated at 0.6 mmboe and the risked estimated cost to bring these resources on commercial production is $12.6 MM with an expected timeline of 5 to 6 years.
Phobos Prospect	Based on reservoir, and closure risk, economic factors and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 50%. The corresponding chance of commerciality is 25%. Risked best estimate prospective resources have been estimated at 0.5 mmboe and the risked estimated cost to bring these resources on commercial production is $20.6 MM with an expected timeline of 9 to 10 years.
Charmottes Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 50%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 0.5 mmboe and the risked estimated cost to bring these resources on commercial production is $18.5 MM with an expected timeline of 8 to 10 years.
Bernet Prospect	Based on risks associated with reservoir, seal and trap along with economic factors, and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 65%. The corresponding chance of commerciality is 33%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $6.7 MM with an expected timeline of 5 to 6 years.

Vert Le Grand Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 28%. The corresponding chance of commerciality is 20%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $3.6 MM with an expected timeline of 3 years.
Pays De Born Prospect	Based on reservoir, seal and trap risk, along with economic factors and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 50%. The corresponding chance of commerciality is 25%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $2.6 MM with an expected timeline of 8 to 9 years.

Les Genets Prospect	Based on reservoir, seal and closure risk, along with economic factors and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 16%. The corresponding chance of commerciality is 9.6%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $0.9 MM with an expected timeline of 9 years.
North Acacias Prospect	Based on reservoir, seal and trap risk, along with economic factors and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 39%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 0.08 mmboe and the risked estimated cost to bring these resources on commercial production is $1.2 MM with an expected timeline of 6 to 7 years.

(14) Prospective resources for Germany have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 60% and the aggregate CoDis at 41%. The corresponding chance of commerciality is 25%. Risked best estimate prospective resources have been estimated at an aggregate of 28.3 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of 173.6MM. The expected development timeline is 2 to 15 years.

Ihlow Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 71%, and the CoDis at 51%. The corresponding chance of commerciality is 36%. Risked best estimate prospective resources have been estimated at 6.6 mmboe and the risked estimated cost to bring these resources on commercial production is $44.7 MM with an expected timeline of 8 years.
Wisselshorst A Prospect	Based on seal and trap risk along with development timing , GLJ has estimated the CoDev at 90%, and the CoDis at 45%. The corresponding chance of commerciality is 41%. Risked best estimate prospective resources have been estimated at 4.8 mmboe and the risked estimated cost to bring these resources on commercial production is $32.2 MM with an expected timeline of 8 years.
Simonswolde South Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 71%, and the CoDis at 48%. The corresponding chance of commerciality is 34%. Risked best estimate prospective resources have been estimated at 4.1 mmboe and the risked estimated cost to bring these resources on commercial production is $14.6 MM with an expected timeline of 10 years.
Klosterseelte Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 49%, and the CoDis at 49%. The corresponding chance of commerciality is 24%. Risked best estimate prospective resources have been estimated at 2.8 mmboe and the risked estimated cost to bring these resources on commercial production is $12.2 MM with an expected timeline of 5 years.
Ohlendorf Prospect	Based on source and trap risk along with development timing, GLJ has estimated the CoDev at 58%, and the CoDis at 30%. The corresponding chance of commerciality is 17%. Risked best estimate prospective resources have been estimated at 2.4 mmboe and the risked estimated cost to bring these resources on commercial production is $10.1 MM with an expected timeline of 15 years.
Wisselshorst B Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 90%, and the CoDis at 38%. The corresponding chance of commerciality is 34%. Risked best estimate prospective resources have been estimated at 2.3 mmboe and the risked estimated cost to bring these resources on commercial production is $17.9 MM with an expected timeline of 11 years.
Jeddeloh Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 38%, and the CoDis at 31%. The corresponding chance of commerciality is 12%. Risked best estimate prospective resources have been estimated at 2.3 mmboe and the risked estimated cost to bring these resources on commercial production is $18.5 MM with an expected timeline of 8 years.
Simonswolde North Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 62%, and the CoDis at 45%. The corresponding chance of commerciality is 28%. Risked best estimate prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $5.6 MM with an expected timeline of 8 years.
Uphuser Meer Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 47%, and the CoDis at 51%. The corresponding chance of commerciality is 24%. Risked best estimate prospective resources have been estimated at 1.0 mmboe and the risked estimated cost to bring these resources on commercial production is $4.5 MM with an expected timeline of 9 years.
Burgmoor Z5 Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 63%, and the CoDis at 52%. The corresponding chance of commerciality is 33%. Risked best estimate prospective resources have been estimated at 0.7 mmboe and the risked estimated cost to bring these resources on commercial production is $2.8 MM with an expected timeline of 2 years.
Wellie Prospect	Based on reservoir, seal and source risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDis at 20%. The corresponding chance of commerciality is 6%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3 MM with an expected timeline of 11 years.

Otterstedt Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 46%, and the CoDis at 34%. The corresponding chance of commerciality is 16%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3.2 MM with an expected timeline of 14 years..
Widdernhausen East Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDis at 44%. The corresponding chance of commerciality is 14%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $2.1 MM with an expected timeline of 12 years.
Ostervesede Prospect	Based on reservoir and seal risk along with development timing, GLJ has estimated the CoDev at 23%, and the CoDis at 25%. The corresponding chance of commerciality is 6%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $0.7 MM with an expected timeline of 11years.

(15) Prospective resources for Netherlands have been estimated based on the factors outlined below. GLJ has estimated the aggregate CoDev at 40% and the aggregate CoDis at 30%. The corresponding chance of commerciality is 12%. Risked best estimate prospective resources have been estimated at an aggregate of 10.1 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of 88.2 MM with an expected timeline of 2 to 12 years.

Prospective resources for Netherlands East have been estimated based on the individual areas outlined below. GLJ has estimated the aggregate CoDev at 25% and the aggregate CoDis at 44%. The corresponding chance of commerciality is 11%. Risked best estimate prospective resources have been estimated at an aggregate of 8.0 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of 66.3 MM with an expected timeline of 2 to 12 years.

- Chance of discovery provided for 111 prospective reservoir targets across 92 prospective locations. Risk primarily associated with presence of reservoir and seal as region proven to have adequate source, migration and timing to charge target reservoirs.
- Chance of development risked to account for company commitment and development timing, anticipated timing for permitting in respective licenses and distance to export (i.e. pipeline/facility requirements to transport gas to sales point). Chance of development is also a function of prospect size.
- 92 prospects summed probabilistically across 13 development groups to appropriately allocate required infrastructure capital across multiple prospective targets within reasonable proximity. As probabilistic summation of the groups resulted in strong economic indicators, no further minimum economic field size calculations were applied as they were considered to have nominal impact.

Prospective resources for Netherlands West have been estimated based on the factors outlined below. GLJ has estimated the aggregate CoDev at 65% and the aggregate CoDis at 28%. The corresponding chance of commerciality is 18%. Risked best estimate prospective resources have been estimated at an aggregate of 2.1 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of$ 21.8 MM with an expected timeline of 2 to 9 years.

- Chance of discovery provided for 10 prospective reservoir targets across 11 prospective locations. Risk primarily associated with presence of reservoir and seal as region proven to have adequate source, migration and timing to charge target reservoirs.
- Chance of development risked to account for company commitment and development timing, anticipated timing for permitting in respective licenses and distance to export (i.e. pipeline/facility requirements to transport gas to sales point). Chance of development is also a function of prospect size.
- 11 prospects summed probabilistically across 3 development groups to appropriately allocate required infrastructure capital across multiple prospective targets within reasonable proximity. As probabilistic summation of the groups resulted in strong economic indicators no further minimum economic field size calculations were applied as they were considered to have nominal impact.

APPENDIX B
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR (FORM 51-101F2)

To the Board of Directors of Vermilion Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	December 31, 2015	Australia	-	376,474	-	376,474
GLJ Petroleum Consultants	December 31, 2015	Canada	-	1,416,572	-	1,416,572
GLJ Petroleum Consultants	December 31, 2015	France	-	1,569,992	-	1,569,992
GLJ Petroleum Consultants	December 31, 2015	Germany	-	77,544	-	77,544
GLJ Petroleum Consultants	December 31, 2015	Ireland	-	666,013	-	666,013
GLJ Petroleum Consultants	December 31, 2015	Netherlands	-	280,337	-	280,337
GLJ Petroleum Consultants	December 31, 2015	USA	-	70,085	-	70,085
Total			-	4,457,018	-	4,457,018

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 1, 2017

"*Jodi L. Anhorn*"
Jodi L. Anhorn, M.Sc., P.Eng.

Executive Vice President & COO

APPENDIX B - PART 2
REPORT ON CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR
OR AUDITOR (FORM 51-101F2)

To the board of directors of Vermilion Energy Inc. (the "Company"):

1. We have evaluated the Company's contingent resources data and prospective resources data as at December 31, 2016. The contingent resources data and prospective resources data are risked estimates of volume of contingent resources and prospective resources and related risked net present value of future net revenue as at December 31, 2016, estimated using forecast prices and costs.

2. The contingent resources data and prospective resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent resources data and prospective resources data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the contingent resources data and prospective resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data and prospective resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources and prospective resources (before deduction of income taxes) attributed to contingent resources and prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data and prospective resources data that we have evaluated and reported on to the Company's board of directors:

Contingent Resources

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Mboe)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$) Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Australia	2,440	-	36,438	36,438
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Canada	120,653	-	840,871	840,871
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	France	27,751	-	508,686	508,686
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Germany	4,933	-	50,479	50,479
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Ireland	-	-	-	-
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Netherlands	4,760	-	79,494	79,494
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	USA	37,956	-	390,965	390,965
Total				**198,493**	**-**	**1,906,933**	**1,906,933**

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Mboe)
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Australia	-
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Canada	14,211
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	France	2,539
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Germany	-
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Ireland	-
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	Netherlands	2,757
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2016	USA	-
Total				**19,507**

Prospective Resources

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Mboe)
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2016	Australia	579
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2016	Canada	40,924
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2016	France	9,609
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2016	Germany	28,260
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2016	Ireland	-
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2016	Netherlands	10,138
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2016	USA	-
Total				**89,510**

6. In our opinion, the contingent resources data and prospective resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the contingent resources data and prospective resources that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. Because the contingent resources data and prospective resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

EXECUTED as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 1, 2017

"*Jodi L. Anhorn*"
Jodi L. Anhorn, M.Sc., P.Eng.
Executive Vice President & COO

APPENDIX C
REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION (FORM 51-101F3)

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of Vermilion Energy Inc. (the "Company") are responsible for the preparation and disclosure, or arranging for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, and includes contingent resources data and prospective resources data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data, contingent resources data and prospective resources data. The report of the independent qualified reserves evaluators is presented in Schedule A to the Annual Information Form of the Company for the year ended December 31, 2016.

The Independent Reserves Committee of the Board of Directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data, contingent resources data and prospective resources data with Management and the independent qualified reserves evaluators.

The Independent Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with Management. The Board of Directors has, on the recommendation of the Audit and Independent Reserves Committees, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and prospective resources data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data, contingent resources data and prospective resources data are based on judgements regarding future events, actual results will vary and the variations may be material.

"Anthony Marino"
Anthony Marino, President & Chief Executive Officer

"Curtis Hicks"
Curtis W. Hicks, Executive Vice President and Chief Financial Officer

"Lorenzo Donadeo"
Lorenzo Donadeo, Director and Chairman of the Board

"Claudio A. Ghersinich"
Claudio A. Ghersinich, Director

February 24, 2017

APPENDIX D
TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

I. PURPOSE

The primary function of the Audit Committee (the "Committee") is to assist the Board in fulfilling its oversight responsibilities with respect to the Company's accounting and financing reporting processes and the audit of the Company's financial statements, including oversight of:

A. the integrity of the Company's financial statements;

B. the Company's compliance with legal and regulatory requirements;

C. the independent auditors' qualifications and independence;

D. the financial information that will be provided to the Shareholders and others;

E. the Company's systems of disclosure controls and internal controls regarding finance, accounting, legal compliance and ethics, which management and the Board have established;

F. the performance of the Company's audit processes; and

G. such other matters required by applicable laws and rules of any stock exchange on which the Company's shares are listed for trading.

While the Committee has the responsibilities and powers set forth in its terms of reference, it is not the duty of the Committee to prepare financial statements, plan or conduct audits or to determine that the Company's financial statements and disclosures are complete and accurate and are in accordance with International Financial Reporting Standards and applicable rules and regulations. Primary responsibility for the financial reporting, information systems, risk management, and disclosure controls and internal controls of the Company is vested in management.

II. COMPOSITION AND OPERATIONS

A. The Committee shall be composed of not fewer than three directors and not more than five directors, all of whom are "independent"[1] under the requirements or guidelines for audit committee service under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading.

B. All Committee members shall be "financially literate,"[2] and at least one member shall have "accounting or related financial expertise" as such terms are interpreted by the Board in its business judgment in light of, and in accordance with, the requirements or guidelines for audit committee service under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading. The Committee may include a member who is not financially literate, provided he or she attains this status within a reasonable period of time following his or her appointment and providing the Board has determined that including such member will not materially adversely affect the ability of the Committee to act independently.

C. No Committee member shall serve on the audit committees of more than two other public issuers without prior determination by the Board that such simultaneous service would not impair the ability of such member to serve effectively on the Committee.

D. The Committee shall operate in a manner that is consistent with the Committee Guidelines outlined in Tab 8 of the Board Manual.

E. The Company's auditors shall be advised of the names of the Committee members and will receive notice of and be invited to attend meetings of the Committee, and to be heard at those meetings on matters relating to the auditor's duties.

F. The Committee may request any officer or employee of the Company, or the Company's legal counsel, or any external or internal auditors to attend a meeting of the Committee to provide such pertinent information as the Committee requests or to meet with any members of, or consultants to the Committee. The Committee has the authority to communicate directly with the internal and external auditors as it deems appropriate to consider any matter that the Committee or auditors determine should be brought to the attention of the Board or Shareholders.

G. The Committee shall have the authority to select, retain, terminate and approve the fees and other retention terms of special independent legal counsel and other consultants or advisers to advise the Committee, as it deems necessary or appropriate, at the Company's expense.

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1 Committee members must be "independent", as defined in Sections 1.4 and 1.5 of National Instrument 52-110 and ''independent'' under the requirements of Rule 10A-3 of the Securities Exchange Act of 1934, as amended, and Section 303A.06 of the NYSE Listed Company Manual.

2 The Board has adopted the NI 52-110 definition of "financial literacy", which is an individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

APPENDIX D
TERMS OF REFERENCE FOR THE AUDIT COMMITTEE (CONTINUED)

H. The Company shall provide for appropriate funding, as determined by the Committee, for payment of (i) compensation to the independent auditors engaged for the purpose of preparing or issuing an audit report or performing other audit review or attest services for the Company, (ii) compensation to any advisers employed by the Committee and (iii) ordinary administrative expenses of the Committee that are necessary or appropriate for carrying out its duties.

I. The Committee shall meet at least four times each year.

III. DUTIES AND RESPONSIBILITIES

Subject to the powers and duties of the Board, the Committee will perform the following duties:

A. Financial Statements and Other Financial Information

The Committee will review and recommend for approval to the Board financial information that will be made publicly available. This includes the responsibility to:

i) review and recommend approval of the Company's annual financial statements, MD&A and earnings press release and report to the Board of Directors before the statements are approved by the Board of Directors;
ii) review and recommend approval for release the Company's quarterly financial statements, MD&A and press releases, as well as financial information and earnings guidance provided to analysts and rating agencies;
iii) satisfy itself that adequate procedures are in place for the review of the public disclosure of financial information extracted or derived from the Company's financial statements, other than the public disclosure referred to in items (i) and (ii) above, and periodically assess the adequacy of those procedures; and
iv) review the Annual Information Form and any Prospectus/Private Placement Memorandums.

Review, and where appropriate, discuss:

v) the appropriateness of critical accounting policies and financial reporting practices used by the Company;
vi) major issues regarding accounting principles and financial statement presentations, including any significant proposed changes in financial reporting and accounting principles, policies and practices to be adopted by the Company and major issues as to the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies;
vii) analyses prepared by management or the external auditor setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative International Financial Reporting Standards ("IFRS") methods on the financial statements of the Company and any other opinions sought by management from an independent or other audit firm or advisor with respect to the accounting treatment of a particular item;
viii) any management letter or schedule of unadjusted differences provided by the external auditor and the Company's response to that letter and other material written communication between the external auditor and management;
ix) any problems, difficulties or differences encountered in the course of the audit work including any disagreements with management or restrictions on the scope of the external auditor's activities or on access to requested information and management's response thereto;
x) any new or pending developments in accounting and reporting standards that may affect the Company;
xi) the effect of regulatory and accounting initiatives, as well as any off-balance sheet structures on the financial statements of the Company and other financial disclosures;
xii) any reserves, accruals, provisions or estimates that may have a significant effect upon the financial statements of the Company;
xiii) the use of special purpose entities and the business purpose and economic effect of off balance sheet transactions, arrangements, obligations, guarantees and other relationships of Company and their impact on the reported financial results of the Company;
xiv) the use of any "pro forma" or "adjusted" information not in accordance with generally accepted accounting principles;
xv) any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters may be, or have been, disclosed in the financial statements; and
xvi) accounting, tax and financial aspects of the operations of the Company as the Committee considers appropriate.

APPENDIX D
TERMS OF REFERENCE FOR THE AUDIT COMMITTEE (CONTINUED)

B. Risk Management, Internal Control and Information Systems

The Committee will review and discuss with management, and obtain reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information. This includes the responsibility to:

i) review the Company's risk management controls and policies with specific responsibility for Credit & Counterparty, Market & Financial, Political and Strategic & Repatriation risks;

ii) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through separate and periodic discussions with and reports from management, the internal auditor and external auditor; and

iii) review management steps to implement and maintain appropriate internal control procedures including a review of policies.

C. External Audit

The external auditor is required to report directly to the Committee, which will review the planning and results of external audit activities and the ongoing relationship with the external auditor. This includes:

i) review and recommend to the Board, for Shareholder approval, the appointment of the external auditor;

ii) review and approve the annual external audit plan, including but not limited to the following:
   a) engagement letter between the external auditor and financial management of the Company;
   b) objectives and scope of the external audit work;
   c) procedures for quarterly review of financial statements;
   d) materiality limit;
   e) areas of audit risk;
   f) staffing;
   g) timetable; and
   h) compensation and fees to be paid by the Company to the external auditor.

iii) meet with the external auditor to discuss the Company's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;

iv) maintain oversight of the external auditor's work and advise the Board, including but not limited to:
   a) the resolution of any disagreements between management and the external auditor regarding financial reporting;
   b) any significant accounting or financial reporting issue;
   c) the auditors' evaluation of the Company's system of internal controls, procedures and documentation;
   d) the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weaknesses;
   e) any other matters the external auditor brings to the Committee's attention; and
   f) evaluate and assess the qualifications and performance of the external auditors for recommendation to the Board as to the appointment or reappointment of the external auditor to be proposed for approval by the Shareholders, and ensuring that such auditors are participants in good standing pursuant to applicable regulatory laws.

v) review the auditor's report on all material subsidiaries;

vi) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Company and its affiliates in order to determine the external auditors' independence, including, without limitation:
   a) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors, including a list of all relationships between the external auditor and the Company that may reasonably be thought to bear on the independence of the external auditors with respect to the Company;
   b) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors; and
   c) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

vii) annually request and review a report from the external auditor regarding (a) the external auditor’s quality-control procedures, (b) any material issues raised by the most recent quality-control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm, and (c) any steps taken to deal with any such issues;

viii) review and pre-approve any non-audit services to be provided to the Company or any affiliates by the external auditor's firm or its affiliates (including estimated fees), and consider the impact on the independence of the external audit;

ix) review the disclosure with respect to its pre-approval of audit and non-audit services provided by the external auditors; and

x) meet periodically, and at least annually, with the external auditor without management present.

APPENDIX D
TERMS OF REFERENCE FOR THE AUDIT COMMITTEE (CONTINUED)

D. Compliance

The Committee shall:

i) Ensure that the external auditor's fees are disclosed by category in the Annual Information Form in compliance with regulatory requirements;
ii) Disclose any specific policies or procedures adopted for pre-approving non-audit services by the external auditor including affirmation that they meet regulatory requirements;
iii) Assist the Governance and Human Resources Committee with preparing the Company's governance disclosure by ensuring it has current and accurate information on:
    a) the independence of each Committee member relative to regulatory requirements for audit committees;
    b) the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status; and
    c) the education and experience of each Committee member relevant to his or her responsibilities as Committee member.
iv) Disclose, if required, if the Company has relied upon any exemptions to the requirements for committees under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading.

E. Other

The Committee shall:

i) establish and periodically review procedures for:
    a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and
    b) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other matters that could negatively affect the Company, such as violations of the Code of Business Conduct and Ethics.
ii) review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor;
iii) review insurance coverage of significant business risks and uncertainties;
iv) review material litigation and its impact on financial reporting;
v) review policies and procedures for the review and approval of officers' expenses and perquisites;
vi) review the policies and practices concerning the expenses and perquisites of the Chairman, including the use of the assets of the Company;
vii) review with external auditors any corporate transactions in which directors or officers of the Company have a personal interest; and
viii) review the terms of reference for the Committee at least annually and otherwise as it deems appropriate, and recommend changes to the Board as required. The Committee shall evaluate its performance with reference to the terms of reference annually.

IV. ACCOUNTABILITY

D. The Committee Chair has the responsibility to make periodic reports to the Board, as requested, on financial and other matters considered by the Committee relative to the Company.

E. The Committee shall report its discussions to the Board by maintaining minutes of its meetings and providing an oral report at the next Board meeting.

ABBREVIATIONS

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in southeast Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
btu	British thermal units
DRIP	Dividend Reinvestment Plan
GJ	gigajoules
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboe	million barrel of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point. Our production in Ireland is priced with reference to NBP.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
TTF	the price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

DISCLAIMER

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

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

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

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

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* and the *Canadian Oil and Gas Evaluation Handbook* . 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is Management's Discussion and Analysis ("MD&A"), dated February 24, 2017, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three months and year ended December 31, 2016 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2016 and 2015, together with the 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 audited consolidated financial statements for the year ended December 31, 2016 and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or, alternatively, "GAAP") as issued by the International Accounting Standards Board.

This MD&A includes references to certain financial and performance measures which do not have standardized meanings prescribed by IFRS. These measures include:

- Fund flows from operations: Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 "Operating Segments". Please see SEGMENTED INFORMATION in the NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS for a reconciliation of fund flows from operations to net earnings. We analyze fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to our ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Netbacks: Netbacks are per boe and per mcf performance measures used in the analysis of operational activities. We assess netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and also versus third party crude oil and natural gas producers.

In addition, this MD&A includes references to certain financial measures which are not specified, defined, or determined under IFRS and are therefore considered non-GAAP financial measures. These non-GAAP financial measures are unlikely to be comparable to similar financial measures presented by other issuers. For a full description of these non-GAAP financial measures and a reconciliation of these measures to their most directly comparable GAAP measures, please refer to "NON-GAAP FINANCIAL MEASURES".

VERMILION'S BUSINESS

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

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

CHANGE IN PRESENTATION

Prior to 2016, we reported our condensate production in Canada and the Netherlands business units within the NGLs production line. Beginning in Q1 2016, we reported condensate production within the crude oil and condensate production line. We believe that this presentation better reflects the historical and forecasted pricing for condensate, which is more closely correlated with crude oil pricing than with pricing for propane, butane and ethane (collectively "NGLs" for the purposes of this report). Comparative periods have been adjusted to reflect this change.

2016 REVIEW AND 2017 GUIDANCE

On November 9, 2015, we announced preliminary 2016 capital expenditure guidance of $350 million and production guidance of between 63,000-65,000 boe/d. On January 5, 2016, in response to the continued weakness in commodity prices we reduced our 2016 capital expenditure guidance to $285 million with corresponding production guidance of 62,500-63,500 boe/d. On February 29, 2016, we further revised our 2016 capital expenditure guidance to $235 million as a result of continued commodity price deterioration. We maintained our production guidance of 62,500-63,500 boe/d. The February 29, 2016 reduction primarily reflected lower expected non-operated drilling activity in Canada, fewer workovers in France, and a deferral of our Netherlands pipeline twinning program. On August 8, 2016, we modestly increased our 2016 capital expenditure guidance to $240 million with the reinstatement of a four-well drilling program in the Champotran field in France and added drilling activity in Canada, partially offset by capital cost savings achieved to date. Actual 2016 capital spending of $242.4 million was within 1% of our guidance and 2016 production of 63,526 boe/d modestly exceeded the top end of our guidance range.

On October 31, 2016, we released our 2017 capital expenditure guidance of $295 million and associated production guidance of between 69,000-70,000 boe/d.

The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2016 Guidance			
2016 Guidance	November 9, 2015	350	63,000 to 65,000
2016 Guidance	January 5, 2016	285	62,500 to 63,500
2016 Guidance	February 29, 2016	235	62,500 to 63,500
2016 Guidance	August 8, 2016	240	62,500 to 63,500
2017 Guidance			
2017 Guidance	October 31, 2016	295	69,000 to 70,000

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2016	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Production								
Crude oil and condensate (bbls/d)	**25,972**	27,842	31,304	(7%)	(17%)	**27,852**	30,408	(8%)
NGLs (bbls/d)	**2,467**	2,478	2,739	-	(10%)	**2,582**	2,308	12%
Natural gas (mmcf/d)	**194.54**	199.66	162.09	(3%)	20%	**198.55**	133.24	49%
Total (boe/d)	**60,863**	63,596	61,058	(4%)	-	**63,526**	54,922	16%
Sales								
Crude oil and condensate (bbls/d)	**26,610**	30,111	32,306	(12%)	(18%)	**28,005**	30,178	(7%)
NGLs (bbls/d)	**2,467**	2,478	2,739	-	(10%)	**2,582**	2,308	12%
Natural gas (mmcf/d)	**194.54**	199.66	162.09	(3%)	20%	**198.55**	133.24	49%
Total (boe/d)	**61,501**	65,865	62,061	(7%)	(1%)	**63,679**	54,692	16%
Build (draw) in inventory (mbbls)	**(58)**	(209)	(93)			**(55)**	84	
Financial metrics								
Fund flows from operations ($M)	**149,582**	140,974	136,441	6%	10%	**510,791**	516,167	(1%)
Per share ($/basic share)	**1.27**	1.21	1.22	5%	4%	**4.41**	4.71	(6%)
Net loss	**(4,032)**	(14,475)	(142,080)	(72%)	(97%)	**(160,051)**	(217,302)	(26%)
Per share ($/basic share)	**(0.03)**	(0.12)	(1.28)	(75%)	(98%)	**(1.38)**	(1.98)	(30%)
Net debt ($M)	**1,427,148**	1,343,923	1,381,951	6%	3%	**1,427,148**	1,381,951	3%
Cash dividends ($/share)	**0.645**	0.645	0.645	-	-	**2.580**	2.580	-
Activity								
Capital expenditures ($M)	**66,882**	41,039	128,996	63%	(48%)	**242,408**	486,861	(50%)
Acquisitions ($M)	**78,713**	10,391	6,227	658%	1,164%	**98,524**	28,897	241%
Gross wells drilled	**16.00**	6.00	8.00			**38.00**	53.00	
Net wells drilled	**12.02**	2.08	5.56			**25.50**	36.12	

Operational review

- Increased consolidated average production for the year ended December 31, 2016 by 16% versus 2015. This increase was primarily due to the addition of Corrib production in Ireland. For the three months ended December 31, 2016, production was relatively consistent with the comparable period in 2015 as the addition of Corrib production in Ireland was offset by natural declines and actively managed production in Canada, the Netherlands, and Australia.
- Achieved consolidated average production of 60,863 boe/d in Q4 2016, a 4% decrease from Q3 2016 due to natural declines, the timing of capital projects, and actively managed production in Canada, the Netherlands, and Australia.
- Incurred capital expenditures in Q4 2016 of $66.9 million primarily related to France and Canada. In France, capital expenditures of $31.1 million were incurred related to the drilling of four wells in Champotran and other development activities in the quarter. In Canada, capital expenditures of $16.9 million related primarily to drilling activity.
- For the year ended December 31, 2016, capital expenditures of $242.4 million primarily related to France, Canada, Australia, and the Netherlands. In France, capital expenditures of $68.5 million related to drilling activity and other development activities, including workover and optimization programs in the Aquitaine and Paris basins. In Canada, capital expenditures of $62.7 million related primarily to drilling activity. In Australia, capital expenditures of $59.9 million related primarily to drilling two sidetrack wells and our Wandoo Platforms Life Extension project. In the Netherlands, capital expenditures of $23.7 million related primarily to drilling activity.
- For the year ended December 31, 2016, acquisition spending of $98.5 million related primarily to Germany and the Netherlands. In Germany, acquisition spending of $48.4 million related to the acquisition of operated and non-operated interests in five oil and three gas producing fields. In the Netherlands, acquisition spending of $28.3 million related to the acquisition of an additional 30% working interest in the Drenthe VI production license, which adds 30,000 net acres of land, including 26,000 net acres of undeveloped land and a 30% after payout interest in one well..

Financial review

Net loss

- The net loss for Q4 2016 was $4.0 million ($0.03/basic share), compared to a net loss of $14.5 million ($0.12/basic share) in Q3 2016. The change in the net loss was primarily attributable to higher revenue as a result of higher commodity prices.
- The net loss for Q4 2016 was $4.0 million ($0.03/basic share), compared to a net loss of $142.1 million ($1.28/basic share) in Q4 2015. The change was a result of a non-cash gain on business combination recognized in the current quarter and the absence of a non-cash impairment charge recognized in Q4 2015, partially offset by an unrealized loss on derivative instruments.
- The net loss for the year ended December 31, 2016 of $160.1 million compared to a net loss of $217.3 million for 2015. The change was primarily a result of a lower non-cash impairment charge in 2016, partially offset by the impact of lower commodity prices and an unrealized loss on derivative instruments.

Fund flows from operations

- Generated fund flows from operations of $149.6 million during Q4 2016, an increase of 6% from Q3 2016. This quarter-over-quarter increase was primarily attributable to higher commodity prices, partially offset by lower sales volumes.
- Fund flows from operations increased by 10% in Q4 2016 as compared to Q4 2015 due to revenue from Ireland and higher crude oil pricing. For the year ended December 31, 2016, fund flows from operations was relatively consistent with the corresponding period in 2015 despite significantly lower commodity prices due to production from Ireland and a 16% reduction in per unit operating costs.

Net debt

- Net debt increased to $1.43 billion as at December 31, 2016 from $1.38 billion at December 31, 2015 primarily due to changes in net current derivatives, partially offset by a decrease in long term debt of $25.7 million as fund flows from operations generated in excess of capital expenditures, abandonment expenditures, net dividends, and acquisitions was used to reduce debt.

Dividends

- Declared dividends of $0.215 per common share per month during the fourth quarter of 2016, totalling $2.58 per common share for the year ended December 31, 2016. This was consistent with dividends declared of $2.58 per common share for the year ended December 31, 2015.

COMMODITY PRICES

	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2016	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Average reference prices								
Crude oil								
WTI (US $/bbl)	**49.29**	44.94	42.18	10%	17%	**43.32**	48.80	(11%)
Edmonton Sweet index (US $/bbl)	**46.18**	42.06	39.72	10%	16%	**40.11**	44.91	(11%)
Dated Brent (US $/bbl)	**49.46**	45.85	43.69	8%	13%	**43.69**	52.46	(17%)
Natural gas								
AECO ($/mmbtu)	**3.09**	2.32	2.46	33%	26%	**2.16**	2.69	(20%)
NBP ($/mmbtu)	**7.51**	5.29	7.41	42%	1%	**6.15**	8.33	(26%)
NBP (€/mmbtu)	**5.22**	3.63	5.07	44%	3%	**4.19**	5.87	(29%)
TTF ($/mmbtu)	**7.21**	5.43	7.28	33%	(1%)	**6.00**	8.23	(27%)
TTF (€/mmbtu)	**5.01**	3.73	4.98	34%	1%	**4.09**	5.80	(29%)
Henry Hub ($/mmbtu)	**3.98**	3.67	3.03	8%	31%	**3.27**	3.41	(4%)
Henry Hub (US $/mmbtu)	**2.98**	2.81	2.27	6%	31%	**2.46**	2.66	(8%)
Average foreign currency exchange rates								
CDN $/US $	**1.33**	1.31	1.34	2%	(1%)	**1.33**	1.28	4%
CDN $/Euro	**1.44**	1.46	1.46	(1%)	(1%)	**1.47**	1.42	4%
Average realized prices ($/boe)								
Canada	**33.48**	28.75	28.94	16%	16%	**26.81**	34.32	(22%)
France	**63.71**	55.88	54.20	14%	18%	**55.15**	62.67	(12%)
Netherlands	**40.84**	31.80	42.61	28%	(4%)	**34.15**	46.77	(27%)
Germany	**36.54**	30.47	39.68	20%	(8%)	**31.97**	43.10	(26%)
Ireland	**44.29**	28.68	-	54%	100%	**35.16**	-	100%
Australia	**69.05**	60.61	58.74	14%	18%	**60.33**	70.22	(14%)
United States	**53.58**	44.53	41.94	20%	28%	**43.70**	47.53	(8%)
Consolidated	**45.93**	38.40	41.04	20%	12%	**37.88**	47.07	(20%)
Production mix (% of production)								
% priced with reference to WTI	**18%**	19%	22%			**19%**	25%	
% priced with reference to AECO	**20%**	20%	24%			**22%**	22%	
% priced with reference to TTF and NBP	**33%**	32%	20%			**30%**	19%	
% priced with reference to Dated Brent	**29%**	29%	34%			**29%**	34%	

- Crude oil prices in Q4 2016 were higher as compared to both Q3 2016 and Q4 2015 as OPEC and select non-OPEC countries reached an agreement to cut output for the first six months of 2017. This coordinated effort to curb the surplus supply of crude oil resulted in an increase in WTI of 10% as compared to Q3 2016 and 17% as compared to Q4 2015. Similarly, Dated Brent increased 8% as compared to Q3 2016 and 13% as compared to Q4 2015.
- An early start to winter increased demand for AECO natural gas both domestically and for exports to the US. For the three months ended December 31, 2016, the AECO price increased 33% and 26%, respectively, versus Q3 2016 and Q4 2015. In Q4 2016, Henry Hub prices increased by 6% and 31% versus Q3 2016 and Q4 2015, respectively, as US supply/demand fundamentals showed signs of tightening.
- European natural gas prices increased in Q4 2016 as higher power sector demand, gas-in-storage constraints and lower-than-expected LNG imports resulted in tighter balances. For the three months ended December 31, 2016, NBP and TTF increased by 42% and 33%, respectively, in Canadian dollar terms versus Q3 2016, and were effectively unchanged versus Q4 2015.
- A highly anticipated 25 basis points rate hike by the US Federal Reserve in Q4 2016 resulted in the Canadian dollar weakening against the US dollar.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Year Ended			
	Dec 31, 2016		Sep 30, 2016		Dec 31, 2015		Dec 31, 2016		Dec 31, 2015	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**259,891**	**45.93**	232,660	38.40	234,319	41.04	**882,791**	**37.88**	939,586	47.07
Royalties	**(14,999)**	**(2.65)**	(12,969)	(2.14)	(16,285)	(2.85)	**(54,284)**	**(2.33)**	(65,920)	(3.30)
Petroleum and natural gas revenues	**244,892**	**43.28**	219,691	36.26	218,034	38.19	**828,507**	**35.55**	873,666	43.77
Transportation	**(9,565)**	**(1.69)**	(9,696)	(1.60)	(10,147)	(1.78)	**(39,511)**	**(1.70)**	(41,660)	(2.09)
Operating	**(59,616)**	**(10.54)**	(54,825)	(9.05)	(65,645)	(11.50)	**(222,185)**	**(9.53)**	(225,938)	(11.32)
General and administration	**(11,464)**	**(2.03)**	(12,295)	(2.03)	(12,431)	(2.18)	**(52,829)**	**(2.27)**	(53,584)	(2.68)
PRRT	**(1,568)**	**(0.28)**	272	0.04	(1,054)	(0.18)	**(1,568)**	**(0.07)**	(6,878)	(0.34)
Corporate income taxes	**(5,840)**	**(1.03)**	(3,546)	(0.59)	3,113	0.55	**(18,110)**	**(0.78)**	(44,237)	(2.22)
Interest expense	**(14,410)**	**(2.55)**	(14,150)	(2.34)	(16,584)	(2.90)	**(56,957)**	**(2.44)**	(59,852)	(3.00)
Realized gain on derivative instruments	**1,920**	**0.34**	13,532	2.23	21,164	3.71	**65,376**	**2.81**	41,356	2.07
Realized foreign exchange gain (loss)	**1,291**	**0.23**	2,073	0.34	(252)	(0.04)	**4,041**	**0.17**	623	0.03
Realized other income (expense)	**3,942**	**0.70**	(82)	(0.01)	243	0.04	**4,027**	**0.17**	32,671	1.64
Fund flows from operations	**149,582**	**26.43**	140,974	23.25	136,441	23.91	**510,791**	**21.91**	516,167	25.86

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

($M)	Q4/16 vs. Q3/16	Q4/16 vs. Q4/15	2016 vs. 2015
Fund flows from operations – Comparative period	**140,974**	**136,441**	**516,167**
Sales volume variance:			
Canada	(4,835)	(14,094)	(21,614)
France	(2,111)	(1,673)	699
Netherlands	(3,279)	(10,168)	8,917
Germany	135	(838)	(2,249)
Ireland	1,612	42,670	109,099
Australia	(11,171)	(15,327)	(3,500)
United States	(127)	(269)	3,343
Pricing variance on sales volumes:			
WTI	6,708	7,821	(26,730)
AECO	4,582	3,340	(19,719)
Dated Brent	13,504	15,915	(57,688)
TTF and NBP	22,213	(1,805)	(47,353)
Changes in:			
Royalties	(2,030)	1,286	11,636
Transportation	131	582	2,149
Operating	(4,791)	6,029	3,753
General and administration	831	967	755
PRRT	(1,840)	(514)	5,310
Corporate income taxes	(2,294)	(8,953)	26,127
Interest	(260)	2,174	2,895
Realized derivatives	(11,612)	(19,244)	24,020
Realized foreign exchange	(782)	1,543	3,418
Realized other income	4,024	3,699	(28,644)
Fund flows from operations – Current period	**149,582**	**149,582**	**510,791**

Fund flows from operations was $149.6 million during Q4 2016, an increase of 6% from Q3 2016. This quarter-over-quarter increase was primarily attributable to higher commodity prices, partially offset by lower sales volumes.

Fund flows from operations increased by 10% in Q4 2016 as compared to Q4 2015 due to revenue from Ireland and higher crude oil pricing. For the year ended December 31, 2016, fund flows from operations was relatively consistent with the corresponding period in 2015 despite significantly lower commodity prices due to production from Ireland and a 16% reduction in per unit operating costs.

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

CANADA BUSINESS UNIT

Overview

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

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Canada business unit ($M except as indicated)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Production and sales								
Crude oil and condensate (bbls/d)	**7,945**	8,984	10,413	(12%)	(24%)	**9,171**	11,357	(19%)
NGLs (bbls/d)	**2,444**	2,448	2,710	-	(10%)	**2,552**	2,301	11%
Natural gas (mmcf/d)	**75.12**	77.62	87.90	(3%)	(15%)	**84.29**	71.65	18%
Total (boe/d)	**22,910**	24,368	27,773	(6%)	(18%)	**25,771**	25,598	1%
Production mix (% of total)								
Crude oil and condensate	**35%**	37%	37%			**36%**	44%	
NGLs	**11%**	10%	10%			**10%**	9%	
Natural gas	**54%**	53%	53%			**54%**	47%	
Activity								
Capital expenditures	**16,895**	10,421	27,554	62%	(39%)	**62,706**	201,508	(69%)
Acquisitions	**1,378**	10,380	6,169			**13,309**	14,650	
Gross wells drilled	**11.00**	4.00	5.00			**29.00**	42.00	
Net wells drilled	**7.02**	1.20	2.56			**17.62**	26.01	
Financial results								
Sales	**70,573**	64,453	73,952	9%	(5%)	**252,867**	320,613	(21%)
Royalties	**(7,390)**	(4,817)	(7,146)	53%	3%	**(21,475)**	(28,144)	(24%)
Transportation	**(3,504)**	(3,978)	(3,784)	(12%)	(7%)	**(15,392)**	(16,326)	(6%)
Operating	**(18,161)**	(15,579)	(24,575)	17%	(26%)	**(71,543)**	(89,085)	(20%)
General and administration	**(2,035)**	(3,010)	(3,669)	(32%)	(45%)	**(11,826)**	(16,888)	(30%)
Fund flows from operations	**39,483**	37,069	34,778	7%	14%	**132,631**	170,170	(22%)
Netbacks ($/boe)								
Sales	**33.48**	28.75	28.94	16%	16%	**26.81**	34.32	(22%)
Royalties	**(3.51)**	(2.15)	(2.80)	63%	25%	**(2.28)**	(3.01)	(24%)
Transportation	**(1.66)**	(1.77)	(1.48)	(6%)	12%	**(1.63)**	(1.75)	(7%)
Operating	**(8.62)**	(6.95)	(9.62)	24%	(10%)	**(7.59)**	(9.54)	(20%)
General and administration	**(0.97)**	(1.34)	(1.44)	(28%)	(33%)	**(1.25)**	(1.81)	(31%)
Fund flows from operations netback	**18.72**	16.54	13.60	13%	38%	**14.06**	18.21	(23%)
Realized prices								
Crude oil and condensate ($/bbl)	**62.13**	53.96	53.44	15%	16%	**52.44**	57.71	(9%)
NGLs ($/bbl)	**18.12**	12.49	7.89	45%	130%	**11.75**	10.32	14%
Natural gas ($/mmbtu)	**3.05**	2.39	2.57	28%	19%	**2.14**	2.78	(23%)
Total ($/boe)	**33.48**	28.75	28.94	16%	16%	**26.81**	34.32	(22%)
Reference prices								
WTI (US $/bbl)	**49.29**	44.94	42.18	10%	17%	**43.32**	48.80	(11%)
Edmonton Sweet index (US $/bbl)	**46.18**	42.06	39.72	10%	16%	**40.11**	44.91	(11%)
Edmonton Sweet index ($/bbl)	**61.60**	54.89	53.04	12%	16%	**53.17**	57.43	(7%)
AECO ($/mmbtu)	**3.09**	2.32	2.46	33%	26%	**2.16**	2.69	(20%)

Production

- Q4 2016 average production in Canada decreased by 6% quarter-over-quarter and 18% year-over-year due to production declines, cold weather related issues and the voluntary curtailment of approximately 13 mmcf/d (2,350 boe/d) of gas weighted production during the quarter. Full year average production increased 1% versus 2015 primarily due to strong organic production in our Mannville condensate-rich gas play offsetting declines in our Cardium and Saskatchewan Midale light oil plays.

- Cardium production averaged approximately 6,100 boe/d in Q4 2016, a 7% decrease quarter-over-quarter. Full year 2016 production averaged approximately 6,700 boe/d.
- Mannville production averaged approximately 9,600 boe/d in Q4 2016 representing a 6% decrease quarter-over-quarter. Full year 2016 production averaged more than 11,000 boe/d.
- Production from southeast Saskatchewan averaged approximately 2,100 boe/d in Q4 2016, a decrease of 13% quarter-over-quarter.

Activity review

- Vermilion drilled seven (6.0 net) operated wells and participated in the drilling of five (1.5 net) non-operated wells during Q4 2016. During 2016, Vermilion drilled 14 (12.6 net) operated wells and participated in the drilling of 15 (5.0 net) non-operated wells in Canada.

Cardium

- In 2016, we participated in the drilling of two (0.2 net) non-operated wells and three (0.5 net) non-operated wells were brought on production.
- In 2017, we plan to drill or participate in nine (6.0 net) wells.

Mannville

- During Q4 2016, we drilled seven (6.0 net) operated wells and participated in the drilling of four (1.5 net) non-operated wells.
- In 2016, we drilled or participated in 20 (12.0 net) wells.
- In 2017, we plan to drill or participate in 23 (15.0 net) wells and complete and tie-in six (5.0 net) wells drilled in 2016.

Saskatchewan

- During Q1 and Q2 2016, we drilled four (4.0 net) operated wells and participated in three (1.5 net) non-operated wells. We plan to complete and bring the four operated wells on production in Q1 2017. The non-operated wells were brought on production during the first half of 2016.
- In 2017, we plan to drill or participate in 13 (11.3 net) wells.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI, and is also subject to market conditions in western Canada. These market conditions can result in fluctuations in the pricing differential to WTI, as reflected by the Edmonton Sweet index price. The realized price of our NGLs in Canada is based on product specific differentials pertaining to trading hubs in the United States. The realized price of our natural gas in Canada is based on the AECO index in Canada.
- Q4 2016 sales per boe increased versus Q3 2016 and Q4 2015 due to stronger crude oil and natural gas pricing.
- Sales per boe for the year ended December 31, 2016 decreased versus the comparable period in 2015, primarily as a result of lower average crude oil and natural gas pricing.

Royalties

- Royalties as a percentage of sales for Q4 2016 increased to 10.5% as compared to 7.5% in Q3 2016 and 9.7% in Q4 2015 due to the impact of higher reference prices on the sliding scale used to determine royalty rates.
- Royalties as a percentage of sales for the year ended December 31, 2016 was 8.5% versus 8.8% in 2015 as the impact of lower reference prices more than offset wells coming off of incentive royalty rates after reaching specified production thresholds.

Transportation

- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense for Q4 2016 was lower than Q3 2016 and Q4 2015 due to lower production.
- Transportation expense for the year ended December 31, 2016 was 6% lower than the prior year while production increased 1%. This was due to a lower oil weighting, which incurs a higher per unit expense, and a reduction in transportation rates.

Operating

- Operating expense was higher on an absolute dollar and per boe basis in Q4 2016 versus Q3 2016. This was primarily due to the timing of project and maintenance activity that was executed in the current quarter.
- Operating expense for the three months and year ended December 31, 2016 decreased by 10% and 20% respectively on a per unit basis versus the comparable periods in 2015. Our continued focus on cost reduction initiatives including major project, transportation and other costs resulted in an annual reduction to operating expenses of $17.5 million while growing production by 1%.

General and administration

- General and administration expense fluctuation in Q4 2016 as compared to Q3 2016 was the result of timing of expenditures.
- Year-over-year, 2016 general and administration expense was 30% lower than 2015 due to initiatives to reduce our cost structure.

FRANCE BUSINESS UNIT

Overview

- Entered France in 1997 and completed three subsequent acquisitions, including two in 2012.
- Largest oil producer in France, constituting approximately three-quarters of domestic oil production.
- Low base decline producing assets comprised of large conventional oil fields with high working interests located in the Aquitaine and Paris Basins.
- Identified inventory of workover, infill drilling, and secondary recovery opportunities.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
France business unit ($M except as indicated)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Production								
Crude oil (bbls/d)	**11,220**	11,827	12,537	(5%)	(11%)	**11,896**	12,267	(3%)
Natural gas (mmcf/d)	**0.38**	0.42	1.36	(10%)	(72%)	**0.44**	0.97	(55%)
Total (boe/d)	**11,283**	11,897	12,763	(5%)	(12%)	**11,970**	12,429	(4%)
Sales								
Crude oil (bbls/d)	**12,209**	12,617	12,490	(3%)	(2%)	**12,157**	12,141	-
Natural gas (mmcf/d)	**0.38**	0.42	1.36	(11%)	(72%)	**0.44**	0.97	(54%)
Total (boe/d)	**12,272**	12,687	12,717	(3%)	(3%)	**12,231**	12,302	(1%)
Inventory (mbbls)								
Opening crude oil inventory	**239**	312	239			**243**	197	
Crude oil production	**1,032**	1,088	1,153			**4,354**	4,477	
Crude oil sales	**(1,123)**	(1,161)	(1,149)			**(4,449)**	(4,431)	
Closing crude oil inventory	**148**	239	243			**148**	243	
Activity								
Capital expenditures	**31,127**	11,110	24,085	180%	29%	**68,472**	92,265	(26%)
Acquisitions	**-**	-	79			**-**	317	
Gross wells drilled	**4.00**	-	-			**4.00**	4.00	
Net wells drilled	**4.00**	-	-			**4.00**	4.00	
Financial results								
Sales	**71,926**	65,221	63,411	10%	13%	**246,863**	281,422	(12%)
Royalties	**(6,692)**	(7,069)	(7,198)	(5%)	(7%)	**(27,091)**	(26,958)	-
Transportation	**(3,983)**	(3,586)	(4,275)	11%	(7%)	**(14,758)**	(15,378)	(4%)
Operating	**(11,482)**	(12,933)	(15,792)	(11%)	(27%)	**(50,000)**	(50,718)	(1%)
General and administration	**(5,101)**	(4,590)	(4,894)	11%	4%	**(19,101)**	(20,217)	(6%)
Other income	**3,822**	-	-	100%	100%	**3,822**	31,775	(88%)
Current income taxes	**(2,867)**	955	4,529	(400%)	(163%)	**(2,867)**	(23,764)	(88%)
Fund flows from operations	**45,623**	37,998	35,781	20%	28%	**136,868**	176,162	(22%)
Netbacks ($/boe)								
Sales	**63.71**	55.88	54.20	14%	18%	**55.15**	62.67	(12%)
Royalties	**(5.93)**	(6.06)	(6.15)	(2%)	(4%)	**(6.05)**	(6.00)	1%
Transportation	**(3.53)**	(3.07)	(3.65)	15%	(3%)	**(3.30)**	(3.42)	(4%)
Operating	**(10.17)**	(11.08)	(13.50)	(8%)	(25%)	**(11.17)**	(11.30)	(1%)
General and administration	**(4.52)**	(3.93)	(4.18)	15%	8%	**(4.27)**	(4.50)	(5%)
Other income	**3.39**	-	-	100%	100%	**0.85**	7.08	(88%)
Current income taxes	**(2.54)**	0.82	3.87	(410%)	(166%)	**(0.64)**	(5.29)	(88%)
Fund flows from operations	**40.41**	32.56	30.59	24%	32%	**30.57**	39.24	(22%)
Realized prices								
Crude oil ($/bbl)	**63.99**	56.14	54.88	14%	17%	**55.42**	63.31	(12%)
Natural gas ($/mmbtu)	**1.55**	1.58	2.81	(2%)	(45%)	**1.59**	2.52	(37%)
Total ($/boe)	**63.71**	55.88	54.20	14%	18%	**55.15**	62.67	(12%)
Reference prices								
Dated Brent (US $/bbl)	**49.46**	45.85	43.69	8%	13%	**43.69**	52.46	(17%)
Dated Brent ($/bbl)	**65.97**	59.84	58.34	10%	13%	**57.92**	67.09	(14%)

Production

- Q4 2016 production decreased 5% versus the prior quarter and 12% versus Q4 2015. Full year production decreased 4% versus 2015. Decreased production for the quarter and the year were primarily due to production declines, well downtime and third party restrictions impacting Vic Bilh gas production.

Activity review

- During Q4 2016, we drilled four wells in Champotran and commenced drilling of a horizontal sidetrack well in the Vulaines field, with completion and tie-in planned for early 2017.
- In 2016, additional activity included workover and optimization programs in the Aquitaine and Paris Basins.
- In 2017, we plan to drill our first four (4.0 net) wells in the Neocomian fields in the Paris Basin, in addition to continuing our workover and optimization activities.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q4 2016 sales per boe increased versus Q3 2016 and Q4 2015 as a result of stronger Dated Brent pricing.
- Sales per boe for the year ended December 31, 2016, decreased versus the comparable period in 2015 as a result of lower average crude oil pricing.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- Royalties as a percentage of sales of 9.3% for the three months ended December 31, 2016 was lower than Q3 2016 (10.8%) and Q4 2015 (11.3%) as a result of the impact of fixed RCDM royalties coupled with higher realized pricing in the current quarter. On a year-over-year basis, the royalty rate increased to 11.0% versus 9.6% in 2015 due to lower realized pricing in the current year.

Transportation

- Transportation expense per boe for Q4 2016 was higher than Q3 2016 and consistent with Q4 2015. The increase over Q3 2016 was due to the timing of project and maintenance activity executed in the current quarter.
- Transportation expense decreased by 4% for 2016 versus 2015 as a result of initiatives to reduce our cost structure, which included vessel cost renegotiation and lower project activity.

Operating

- Operating expense on a dollar and per boe basis decreased in Q4 2016 versus both Q3 2016 and Q4 2015 due to the timing of expenditures and a continued focus on initiatives to reduce costs.
- Year-over-year, operating expense decreased on a dollar and per boe basis in 2016 versus 2015 due to the continuation of focus on cost reduction initiatives identified in 2015 and new initiatives identified in 2016, which more than off-set unfavourable foreign exchange rates as the Canadian dollar weakened versus the Euro. After normalizing for the unfavorable foreign exchange, per unit costs decreased 4.5% in 2016.

General and administration

- General and administration expense for Q4 2016 was 11% higher than Q3 2016 and 4% higher than Q4 2015 due to the timing of expenditures and recoveries.
- Year-over-year, 2016 general and administration expense was 6% lower than 2015 due to the impact of cost reduction initiatives.

Other income

- In 2015, Vermilion was awarded a recovery of costs resulting from an oil spill at the Ambès oil terminal in France that occurred in 2007. The court awarded Vermilion approximately €25 million (before taxes), of which 50% was due immediately to Vermilion upon posting a surety bond. The payment was received in 2015, with the remainder due upon conclusion of the appeal process. Approximately 90% of the recovery was recorded as other income in 2015.
- In Q4 2016, the Court of Appeal of Versailles maintained this award. The remaining payment was received and Vermilion's surety bond was returned in 2017. The remaining amount of the recovery was recognized as other income in 2016.

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 34.4% for 2016.
- Current income taxes in Q4 2016 were higher compared to Q3 2016 due to increased sales and other income. Q4 2016 current income taxes were higher compared to Q4 2015 due to increased sales and the reversal of tax depletion impairments taken in Q4 2015.
- Current income taxes for the year ended December 31, 2016 were lower versus the comparative period in 2015 as a result of decreased sales and other income.

NETHERLANDS BUSINESS UNIT

Overview

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

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Netherlands business unit ($M except as indicated)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Production and sales								
Condensate (bbls/d)	**57**	86	110	(34%)	(48%)	**88**	99	(11%)
Natural gas (mmcf/d)	**41.15**	47.62	56.34	(14%)	(27%)	**47.82**	44.76	7%
Total (boe/d)	**6,915**	8,023	9,500	(14%)	(27%)	**8,058**	7,559	7%
Activity								
Capital expenditures	**5,737**	6,441	18,810	(11%)	(70%)	**23,740**	47,325	(50%)
Acquisitions	**28,259**	-	-			**28,259**	-	
Gross wells drilled	**-**	2.00	-			**2.00**	2.00	
Net wells drilled	**-**	0.88	-			**0.88**	1.86	
Financial results								
Sales	**25,978**	23,470	37,243	11%	(30%)	**100,707**	129,057	(22%)
Royalties	**(294)**	(312)	(224)	(6%)	31%	**(1,462)**	(3,082)	(53%)
Operating	**(5,660)**	(4,854)	(6,263)	17%	(10%)	**(20,796)**	(22,746)	(9%)
General and administration	**(162)**	633	(813)	(126%)	(80%)	**(1,525)**	(4,158)	(63%)
Current income taxes	**100**	(1,264)	(2,930)	(108%)	(103%)	**(6,624)**	(12,152)	(45%)
Fund flows from operations	**19,962**	17,673	27,013	13%	(26%)	**70,300**	86,919	(19%)
Netbacks ($/boe)								
Sales	**40.84**	31.80	42.61	28%	(4%)	**34.15**	46.77	(27%)
Royalties	**(0.46)**	(0.42)	(0.26)	10%	77%	**(0.50)**	(1.12)	(55%)
Operating	**(8.90)**	(6.58)	(7.17)	35%	24%	**(7.05)**	(8.24)	(14%)
General and administration	**(0.26)**	0.86	(0.93)	(130%)	(72%)	**(0.52)**	(1.51)	(66%)
Current income taxes	**0.16**	(1.71)	(3.35)	(109%)	(105%)	**(2.25)**	(4.40)	(49%)
Fund flows from operations netback	**31.38**	23.95	30.90	31%	2%	**23.83**	31.50	(24%)
Realized prices								
Condensate ($/bbl)	**63.18**	49.43	48.30	28%	31%	**44.93**	49.98	(10%)
Natural gas ($/mmbtu)	**6.78**	5.27	7.09	29%	(4%)	**5.67**	7.79	(27%)
Total ($/boe)	**40.84**	31.80	42.61	28%	(4%)	**34.15**	46.77	(27%)
Reference prices								
TTF ($/mmbtu)	**7.21**	5.43	7.28	33%	(1%)	**6.00**	8.23	(27%)
TTF (€/mmbtu)	**5.01**	3.73	4.98	34%	1%	**4.09**	5.80	(29%)

Production

- Q4 2016 production decreased 14% quarter-over-quarter and 27% year-over-year due to production curtailments in accordance with extended well test plans and management of production to meet corporate production targets.
- Full year 2016 production increased 7% versus 2015, primarily due to production additions from Slootdorp-06/07 and Diever-02 wells, which were on extended production test.
- Production in the Netherlands is actively managed to optimize facility use and regulate declines.

Activity review

- During Q3 2016, Vermilion drilled two (0.9 net) wells. Langezwaag-3 (42% working interest) was completed and brought on production during Q4 2016, at a restricted rate of 7.5 mmcf/d. The Andel-6ST (45% working interest) encountered a large gas column of inadequate reservoir quality to justify completion.
- During Q4 2016, we acquired an additional 30% working interest in the Drenthe VI production license, adding 30,000 net acres of land, including 26,000 net acres of undeveloped land and a 30% after payout interest in one well.
- In 2017, we plan to drill two (1.0 net) exploration wells, acquire 230 square kilometres of 3D seismic and execute a major turnaround at the Garijp Treatment Centre.

Sales
- The price of our natural gas in the Netherlands is based on the TTF index.
- Q4 2016 sales per boe increased versus Q3 2016 consistent with an increase in the TTF reference price.
- Sales per boe for the three months ended December 31, 2016 were relatively consistent with the comparable period in 2015. For the year ended December 31, 2016, sales per boe decreased consistent with a decrease in the TTF reference price.

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

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

Operating
- Q4 2016 operating expense on a per boe basis increased versus Q3 2016 and Q4 2015 due to increased project activity and lower recoveries.
- Year-over-year, 2016 operating expense decreased by 9% on a dollar basis while growing production by 7% resulting in a 14% per unit decrease as a result of focus on initiatives to reduce our cost structure.

General and administration
- Variances in general and administration expense from quarter to quarter relate to timing of expenditures, including the timing of allocations from Vermilion's Corporate segment.
- Year-over-year the decrease in general and administration is primarily due to lower head office allocations.

Current income taxes
- In the Netherlands, current income taxes are applied to taxable income, after eligible deductions and a 10% uplift deduction applied to operating expenses, eligible G&A and tax deductions for depletion and abandonment retirement obligations, at a tax rate of 50%.
- Current income taxes in Q4 2016 were lower compared to Q3 2016 due to increased tax deductions for current year capital expenditures. Q4 2016 current income taxes were lower compared to Q4 2015 mainly due to decreased sales.
- Current income taxes for the year ended December 31, 2016 were lower versus the comparative period in 2015 due to decreased operating income in 2016, partially offset by additional tax deductions for capital expenditures in 2015.

GERMANY BUSINESS UNIT

Overview

- Vermilion entered Germany in February 2014.
- Hold a 25% interest in a four partner consortium. Associated assets include four gas producing fields spanning 11 production licenses as well as an exploration license in surrounding fields. Total license area comprises 204,000 gross acres, of which 85% is in the exploration license.
- Entered into a farm-in agreement in July 2015 that provides Vermilion with participating interest in 18 onshore exploration licenses in northwest Germany, comprising approximately 850,000 net undeveloped acres of oil and natural gas rights. Vermilion will operate 11 of the 18 licenses during the exploration phase.
- Awarded 110,000 net acres (100% working interest) across two exploration licenses in the Lower Saxony basin in 2015.
- In December 2016, Vermilion closed the acquisition of operated and non-operated interests in five oil and three gas producing fields from Engie E&P Deutschland GmbH. Vermilion will assume operatorship of six of the eight producing fields. During 2016, the assets produced approximately 2,000 boe/d (50% oil), representing our first operated producing properties in Germany.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Germany business unit ($M except as indicated)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Production and sales								
Natural gas (mmcf/d)	**14.80**	14.52	16.17	2%	(8%)	**14.90**	15.78	(6%)
Total (boe/d)	**2,467**	2,420	2,695	2%	(8%)	**2,483**	2,630	(6%)
Activity								
Capital expenditures	**1,694**	978	(441)	73%	(484%)	**3,803**	5,363	(29%)
Acquisitions	**48,377**	-	-			**48,377**	-	
Gross wells drilled	**-**	-	-			**-**	1.00	
Net wells drilled	**-**	-	-			**-**	0.25	
Financial results								
Sales	**8,294**	6,783	9,840	22%	(16%)	**29,049**	41,384	(30%)
Royalties	**(12)**	(246)	(1,166)	(95%)	(99%)	**(2,089)**	(6,479)	(68%)
Transportation	**(375)**	(556)	(508)	(33%)	(26%)	**(2,869)**	(3,269)	(12%)
Operating	**(3,959)**	(3,321)	(4,788)	19%	(17%)	**(12,379)**	(10,956)	13%
General and administration	**(1,755)**	(1,657)	(3,032)	6%	(42%)	**(8,314)**	(7,386)	13%
Fund flows from operations	**2,193**	1,003	346	119%	534%	**3,398**	13,294	(74%)
Netbacks ($/boe)								
Sales	**36.54**	30.47	39.68	20%	(8%)	**31.97**	43.10	(26%)
Royalties	**(0.06)**	(1.10)	(4.70)	(95%)	(99%)	**(2.30)**	(6.75)	(66%)
Transportation	**(1.65)**	(2.50)	(2.05)	(34%)	(20%)	**(3.16)**	(3.41)	(7%)
Operating	**(17.44)**	(14.92)	(19.31)	17%	(10%)	**(13.62)**	(11.41)	19%
General and administration	**(7.73)**	(7.44)	(12.22)	4%	(37%)	**(9.15)**	(7.69)	19%
Fund flows from operations netback	**9.66**	4.51	1.40	114%	590%	**3.74**	13.84	(73%)
Reference prices								
TTF ($/mmbtu)	**7.21**	5.43	7.28	33%	(1%)	**6.00**	8.23	(27%)
TTF (€/mmbtu)	**5.01**	3.73	4.98	34%	1%	**4.09**	5.80	(29%)

Production

- Q4 2016 production remained consistent with the prior quarter, and decreased 8% versus Q4 2015 and 6% for the full year 2016 versus 2015 mainly due to natural declines.

Activity review

- In 2016, the majority of activity was associated with permitting and pre-drill activities for the Burgmoor Z5 well.
- During December 2016, we completed the acquisition of oil and gas producing properties from Engie E&P Deutschland GmbH, which provides us with our first operated production in the country.
- In 2017, we plan to continue our ongoing analysis of the geologic data associated with the farm-in assets and to continue integration activities associated with the Engie acquisition. We will also continue permitting and pre-drill activities associated our first operated well in Germany, Burgmoor Z5 well (25% working interest) in the Dümmersee-Uchte area, which we plan to drill in 2018.

Sales
- The price of our natural gas in Germany is based on the TTF index.
- Q4 2016 sales per boe increased versus Q3 2016, consistent with an increase in the TTF reference price. Q4 2016 sales per boe decreased versus Q4 2015 as a result of a decrease in the TTF month-ahead index on which sales in Germany are primarily based.
- For the year ended December 31, 2016, sales per boe decreased compared to 2015, consistent with a decline in the TTF reference price.

Royalties
- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Q4 2016 royalties as a percentage of sales was a negligible amount versus 3.6% in Q3 2016 and 11.8% in Q4 2015. The decrease in Q4 2016 was due to favourable adjustments from prior periods.
- Full year 2016 royalties as a percentage of sales was 7.2% versus 15.7% in 2015 as a result of favourable prior year adjustments impacting 2016.

Transportation
- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer.
- Q4 2016 transportation expense decreased from Q3 2016 due to seasonal changes in the level of transportation facility maintenance, which is typically higher at the beginning of the year.
- Year-over-year transportation expense decreased due to a decrease in volumes and a reduction in unfavourable prior period adjustments in 2016.

Operating
- Operating expenses for Germany primarily relate to tariffs charged for facility operations and gas processing.
- Operating expense for Q4 2016 increased versus Q3 2016 due to increased project activity.
- Full year operating expense was higher on a dollar and per boe basis due to an unfavorable adjustment from the prior year recorded in 2016 and increased project activity.

General and administration
- Q4 2016 general and administration expense was higher than Q3 2016 and lower than Q4 2015 due to timing of head office allocations.
- Full year 2016 general and administration expense increased over 2015 due to higher staffing levels and office costs incurred to support our farm-in agreement as well as costs incurred to support asset acquisition activity.
- We expect per unit general and administration costs to improve as our production base in Germany grows.

IRELAND BUSINESS UNIT

Overview

- 18.5% non-operating interest in the offshore Corrib gas field located approximately 83 km off the northwest coast of Ireland.
- Project comprises six offshore wells, offshore and onshore sales and transportation pipeline segments as well as a natural gas processing facility.
- Production volumes reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion, at the end of Q2 2016.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Ireland business unit ($M except as indicated)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Production and sales								
Natural gas (mmcf/d)	**62.92**	59.28	0.12	6%	52,771%	**50.89**	0.03	169,547%
Total (boe/d)	**10,486**	9,879	20.00	6%	52,330%	**8,482**	5.00	169,540%
Activity								
Capital expenditures	**1,711**	2,416	12,493	(29%)	(86%)	**9,375**	66,409	(86%)
Financial results								
Sales	**42,727**	26,065	57	64%	74,860%	**109,156**	57	191,402%
Transportation	**(1,703)**	(1,576)	(1,580)	8%	8%	**(6,492)**	(6,687)	(3%)
Operating	**(5,148)**	(4,695)	(15)	10%	34,220%	**(18,646)**	(15)	124,207%
General and administration	**(1,523)**	(955)	(714)	59%	113%	**(4,772)**	(2,517)	90%
Fund flows from operations	**34,353**	18,839	(2,252)	82%	(1,625%)	**79,246**	(9,162)	(965%)
Netbacks ($/boe)								
Sales	**44.29**	28.68	-	54%	100%	**35.16**	-	100%
Transportation	**(1.77)**	(1.73)	-	2%	100%	**(2.09)**	-	100%
Operating	**(5.34)**	(5.17)	-	3%	100%	**(6.01)**	-	100%
General and administration	**(1.58)**	(1.05)	-	50%	100%	**(1.54)**	-	100%
Fund flows from operations netback	**35.60**	20.73	-	72%	100%	**25.52**	-	
Reference prices								
NBP ($/mmbtu)	**7.51**	5.29	7.41	42%	1%	**6.15**	8.33	(26%)
NBP (€/mmbtu)	**5.22**	3.63	5.07	44%	3%	**4.19**	5.87	(29%)

Production

- Natural gas began to flow from our Corrib gas project on December 30, 2015 and production volumes reached full plant capacity of approximately 65 mmcf/d (10,900 boe/d), net to Vermilion at the end of Q2 2016.
- Q4 2016 production increased 6% quarter-over-quarter due to reduced downtime. Full year production averaged 51 mmcf/d (8,482 boe/d) while ramping up to full capacity.
- Production results continued to benefit from better than expected well deliverability and minimal downtime.

Activity review

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

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q4 2016 sales per boe increased relative to Q3 2016, consistent with an increase in the NBP reference price.

Royalties

- Our production in Ireland is not subject to royalties.

Transportation

- Transportation expense in Ireland relates to payments under a ship-or-pay agreement related to the Corrib project.
- Q4 2016 transportation expense increased versus Q3 2016 and Q4 2015 due to a prior period adjustment in the current quarter offsetting the decrease in the ship-or-pay obligation.
- Full year 2016 transportation expense decreased versus 2015 due to the decrease in the ship or pay obligation.

Operating

- Q4 2016 operating expense on a per unit basis was consistent with Q3 2016, contributing to full year 2016 per unit costs of $6.01/boe.

General and administration

- General and administrative expense for the three months ended December 31, 2016 was higher versus Q3 2016 due to timing of expenditures.
- General and administrative expense for the three months and year ended December 31, 2016 was higher than the comparable periods in 2015 due to increased corporate support provided in the first full year of operations.

AUSTRALIA BUSINESS UNIT

Overview

- Entered Australia in 2005.
- Hold a 100% operated working interest in the Wandoo field, located approximately 80 km offshore on the northwest shelf of Australia.
- Production is operated from two off-shore platforms, and originates from 18 well bores and five lateral sidetrack wells.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600 metres below the seabed in approximately 55 metres of water depth.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Australia business unit ($M except as indicated)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Production								
Crude oil (bbls/d)	**6,388**	6,562	7,824	(3%)	(18%)	**6,304**	6,454	(2%)
Sales								
Crude oil (bbls/d)	**6,038**	8,041	8,873	(25%)	(32%)	**6,197**	6,351	(2%)
Inventory (mbbls)								
Opening crude oil inventory	**82**	218	172	(62%)	(52%)	**75**	37	103%
Crude oil production	**588**	604	720	(3%)	(18%)	**2,307**	2,356	(2%)
Crude oil sales	**(555)**	(740)	(817)	(25%)	(32%)	**(2,267)**	(2,318)	(2%)
Closing crude oil inventory	**115**	82	75			**115**	75	
Activity								
Capital expenditures	**5,236**	6,908	40,852	(24%)	(87%)	**59,910**	61,741	(3%)
Gross wells drilled	**-**	-	1.00			**2.00**	1.00	
Net wells drilled	**-**	-	1.00			**2.00**	1.00	
Financial results								
Sales	**38,352**	44,835	47,952	(14%)	(20%)	**136,835**	162,765	(16%)
Operating	**(14,905)**	(13,011)	(13,941)	15%	7%	**(47,507)**	(51,676)	(8%)
General and administration	**(1,998)**	(1,289)	(1,768)	55%	13%	**(6,400)**	(5,754)	11%
PRRT	**(1,568)**	272	(1,054)	(676%)	49%	**(1,568)**	(6,878)	(77%)
Current income taxes	**(2,703)**	(2,916)	1,201	(7%)	(325%)	**(7,522)**	(7,230)	4%
Fund flows from operations	**17,178**	27,891	32,390	(38%)	(47%)	**73,838**	91,227	(19%)
Netbacks ($/boe)								
Sales	**69.05**	60.61	58.74	14%	18%	**60.33**	70.22	(14%)
Operating	**(26.83)**	(17.59)	(17.08)	53%	57%	**(20.95)**	(22.29)	(6%)
General and administration	**(3.60)**	(1.74)	(2.17)	107%	66%	**(2.82)**	(2.48)	14%
PRRT	**(2.82)**	0.37	(1.29)	(862%)	119%	**(0.69)**	(2.97)	(77%)
Current income taxes	**(4.87)**	(3.94)	1.47	24%	(431%)	**(3.32)**	(3.12)	6%
Fund flows from operations netback	**30.93**	37.71	39.67	(18%)	(22%)	**32.55**	39.36	(17%)
Reference prices								
Dated Brent (US $/bbl)	**49.46**	45.85	43.69	8%	13%	**43.69**	52.46	(17%)
Dated Brent ($/bbl)	**65.97**	59.84	58.34	10%	13%	**57.92**	67.09	(14%)

Production

- Q4 2016 production decreased 3% quarter-over-quarter and 18% year-over-year. The year-over-year decrease is primarily due to production decline from the horizontal sidetrack well drilled and placed on production in Q4 2015. Full year 2016 production decreased 2% versus 2015.
- Production volumes are managed within corporate targets while meeting customer demands and the requirements of long-term supply agreements.
- We continue to plan for long-term production levels of between 6,000 and 8,000 bbls/d.

Activity review

- The two sidetrack wells we drilled during Q2 2016 continued to demonstrate strong productive capability with combined production rates of approximately 4,300 bbls/d when utilized. Vermilion intends to produce these wells intermittently to meet corporate production targets while seeking to optimize ultimate recoveries and oil pricing. Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019.
- Additional 2016 activity included work on our Wandoo Platforms Life Extension project, CALM buoy maintenance and subsea inspections.

Sales
- Crude oil in Australia is priced with reference to Dated Brent.
- Q4 2016 sales per boe increased versus Q3 2016 and Q4 2015 consistent with an increase in the Dated Brent reference price. This increase in price was offset by lower sold volumes due to an inventory build in Q4 2016, resulting in a decrease in sales.
- Sales per boe for the year ended December 31, 2016 decreased versus the comparable period in 2015 consistent with a decrease in the Dated Brent reference price.

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

Operating
- Operating expense on a dollar per boe basis increased in Q4 2016 versus Q3 2016 and Q4 2015. The increase was a result of increased project and maintenance work being completed in the current quarter as a result of the drill program being executed earlier in the year.
- Operating expense on a dollar and per boe basis decreased in 2016 versus 2015 due to a continued focus on initiatives to reduce our cost structure resulting in lower diesel, vessel and maintenance costs.

General and administration
- Fluctuation in general and administration expense for Q4 2016 versus the comparable quarters was largely the result of the timing of expenditures. Full year 2016 general and administration expense increased due to higher employee benefit costs.

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 paid.
- Current income taxes in Q4 2016 were lower compared to Q3 2016 due to decreased sales. Q4 2016 current income taxes were higher compared to Q4 2015 as decreased sales were offset by lower tax deductions.
- Current income taxes for the year ended December 31, 2016 were slightly higher versus the comparable period in 2015 as lower sales were offset with increased deductions for PRRT and foreign exchange in 2015.
- PRRT in Q4 2016 was higher compared to Q3 2016 due to the impact of an increase in full year sales (resulting from a significant increase in crude oil pricing) compared to our forecast in Q3 2016. Q4 2016 PRRT was higher compared to Q4 2015 as lower sales were offset with higher deductions for capital expenditures in Q4 2015.
- PRRT for the year ended December 31, 2016, was lower versus the comparable period in 2015 as a result of decreased sales.

UNITED STATES BUSINESS UNIT

Overview

- Entered the United States in September 2014.
- Interests include approximately 97,200 net acres of land (97% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sand at a depth of approximately 1,500 metres.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
United States business unit ($M except as indicated)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Q4/16 vs. Q3/16**	**Q4/16 vs. Q4/15**	**Dec 31, 2016**	**Dec 31, 2015**	**2016 vs. 2015**
Production and sales								
Crude oil (bbls/d)	**362**	383	420	(5%)	(14%)	**393**	231	70%
NGLs (bbls/d)	**23**	30	29	(23%)	(21%)	**29**	7	314%
Natural gas (mmcf/d)	**0.18**	0.20	0.20	(10%)	(13%)	**0.21**	0.05	312%
Total (boe/d)	**414**	447	483	(7%)	(14%)	**457**	247	85%
Activity								
Capital expenditures	**4,037**	2,765	5,643	46%	(28%)	**13,539**	12,250	11%
Acquisitions	**377**	11	(21)			**5,935**	12,764	
Gross wells drilled	**1.00**	-	2.00			**1.00**	3.00	
Net wells drilled	**1.00**	-	2.00			**1.00**	3.00	
Financial results								
Sales	**2,041**	1,833	1,864	11%	9%	**7,314**	4,288	71%
Royalties	**(611)**	(525)	(551)	16%	11%	**(2,167)**	(1,257)	72%
Operating	**(301)**	(432)	(271)	(30%)	11%	**(1,314)**	(742)	77%
General and administration	**(877)**	(918)	(897)	(4%)	(2%)	**(3,624)**	(3,836)	(6%)
Fund flows from operations	**252**	(42)	145	700%	74%	**209**	(1,547)	114%
Netbacks ($/boe)								
Sales	**53.58**	44.53	41.94	20%	28%	**43.70**	47.53	(8%)
Royalties	**(16.05)**	(12.74)	(12.40)	26%	29%	**(12.95)**	(13.93)	(7%)
Operating	**(7.91)**	(10.50)	(6.11)	(25%)	29%	**(7.85)**	(8.23)	(5%)
General and administration	**(23.02)**	(22.30)	(20.18)	3%	14%	**(21.65)**	(42.51)	(49%)
Fund flows from operations netback	**6.60**	(1.01)	3.25	753%	103%	**1.25**	(17.14)	107%
Realized prices								
Crude oil ($/bbl)	**59.09**	51.29	47.59	15%	24%	**49.86**	50.49	(1%)
NGLs ($/bbl)	**19.48**	5.14	5.13	279%	280%	**7.38**	5.13	44%
Natural gas ($/mmbtu)	**1.93**	0.64	0.52	202%	271%	**0.85**	0.52	63%
Total ($/boe)	**53.58**	44.53	41.94	20%	28%	**43.70**	47.53	(8%)
Reference prices								
WTI (US $/bbl)	**49.29**	44.94	42.18	10%	17%	**43.32**	48.80	(11%)
WTI ($/bbl)	**65.75**	58.65	56.32	12%	17%	**57.42**	62.41	(8%)
Henry Hub (US $/mmbtu)	**2.98**	2.81	2.27	6%	31%	**2.46**	2.66	(8%)
Henry Hub ($/mmbtu)	**3.98**	3.67	3.03	8%	31%	**3.27**	3.41	(4%)

Production

- Q4 2016 production decreased 7% quarter-over-quarter and 14% year-over-year due to natural declines.
- Full year 2016 production increased 85% versus 2015 due to production from our two wells drilled in the East Finn prospect in Q4 2015.

Activity

- In Q4 2016, we completed the Seedy Draw East Federal well. The nearly 1,400 metre horizontal lateral was stimulated with 32 frac stages, but due to a screen-out during treatment, only 23 stages were completed. We plan to clean sand out of this well and put it on production during Q1 2017, leaving the remaining nine stages for potential stimulation at a later date.
- During 2016, we drilled one (1.0 net) well, and completed and tied-in two (2.0 net) wells drilled in Q4 2015.
- In 2017, we plan to drill and complete three (3.0 net) wells.

Sales
- The price of crude oil in the United States is directly linked to WTI, but is also subject to market conditions in the United States.
- Q4 2016 sales per boe increased versus Q3 2016 and Q4 2015 consistent with an increase in the WTI reference price.
- Sales per boe for the year ended December 31, 2016 decreased versus the comparable period in 2015, consistent with a decrease in the WTI reference price.

Royalties
- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- Royalties (including severance and ad valorem taxes) as a percentage of sales are approximately 30% and has remained consistent across all periods.

Operating
- The decrease in operating expense for Q4 2016 compared to Q3 2016 and increase from Q4 2015 were primarily due to timing of maintenance and repair activity.
- On a year-over-year basis, per unit costs have decreased 5% due to production growth and initiatives to reduce our cost structure.

General and administration
- On a year-over-year basis initiatives taken to reduce our cost structure have resulted in a 6% reduction in costs while growing production 85%.

CORPORATE

Overview

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

Financial review

	Three Months Ended			Year Ended	
CORPORATE ($M)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Dec 31, 2016**	**Dec 31, 2015**
General and administration recovery (expense)	**1,987**	(509)	3,356	**2,733**	7,172
Current income taxes	**(370)**	(321)	313	**(1,097)**	(1,091)
Interest expense	**(14,410)**	(14,150)	(16,584)	**(56,957)**	(59,852)
Realized gain on derivatives	**1,920**	13,532	21,164	**65,376**	41,356
Realized foreign exchange gain (loss)	**1,291**	2,073	(252)	**4,041**	623
Realized other income (expense)	**120**	(82)	243	**205**	896
Fund flows from operations	**(9,462)**	543	8,240	**14,301**	(10,896)

General and administration

- Fluctuations in general and administration costs for Q4 2016 versus all comparable periods is due to the timing of expenditures and allocations to the various business unit segments.

Current income taxes

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

Interest expense

- Interest expense in Q4 2016 was relatively consistent with Q3 2016.
- The decrease in interest expense for the three months and year ended December 31, 2016 compared to the same periods in 2015, was primarily due to the retiring of our 6.5% senior unsecured notes in February 2016 using funds from our revolving credit facility, partially offset by higher average borrowings under our revolving credit facility.

Hedging

- The nature of our operations results in exposure to fluctuations in commodity prices, interest rates and foreign currency exchange rates. We monitor and, when appropriate, use derivative financial instruments to manage our exposure to these fluctuations and reduce cash flow volatility. 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 collars and swaps. We currently have European gas contracts for 2019 as an exception to our typical horizon.
- We believe that our hedging philosophy and approach increases the stability of revenues, cash flows, and future dividends while also assisting us in the execution of our capital and development plans.
- The realized gain on derivatives in 2016 related primarily to amounts received on our European natural gas hedges.
- A listing of derivative positions as at December 31, 2016 is included in "Supplemental Table 2" of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Year Ended		
($M except per share)	**Dec 31, 2016**	**Dec 31, 2015**	**Dec 31, 2014**
Total assets	**4,087,184**	4,209,220	4,386,091
Long-term debt	**1,362,192**	1,162,998	1,238,080
Petroleum and natural gas sales	**882,791**	939,586	1,419,628
Net (loss) earnings	**(160,051)**	(217,302)	269,326
Net (loss) earnings per share			
Basic	**(1.38)**	(1.98)	2.55
Diluted	**(1.38)**	(1.98)	2.51
Cash dividends ($/share)	**2.58**	2.58	2.58

	Three Months Ended							
($M except per share)	**Dec 31, 2016**	**Sep 30, 2016**	**Jun 30, 2016**	**Mar 31, 2016**	**Dec 31, 2015**	**Sep 30, 2015**	**Jun 30, 2015**	**Mar 31, 2015**
Petroleum and natural gas sales	**259,891**	232,660	212,855	177,385	234,319	245,051	264,331	195,885
Net (loss) earnings	**(4,032)**	(14,475)	(55,696)	(85,848)	(142,080)	(83,310)	6,813	1,275
Net (loss) earnings per share								
Basic	**(0.03)**	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)	0.06	0.01
Diluted	**(0.03)**	(0.12)	(0.48)	(0.76)	(1.28)	(0.76)	0.06	0.01

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

	Three Months Ended			Year Ended	
	Dec 31, 2016	**Sep 30, 2016**	**Dec 31, 2015**	**Dec 31, 2016**	**Dec 31, 2015**
Fund flows from operations	**149,582**	140,974	136,441	**510,791**	516,167
Equity based compensation	**(19,489)**	(15,642)	(21,533)	**(69,235)**	(75,232)
Unrealized (loss) gain on derivative instruments	**(74,943)**	332	27,393	**(137,993)**	43,548
Unrealized foreign exchange (loss) gain	**(2,457)**	2,899	(6,357)	**(792)**	8,787
Unrealized income (expense)	**-**	(24)	(234)	**(131)**	(1,008)
Accretion	**(6,308)**	(6,341)	(6,324)	**(24,783)**	(23,911)
Depletion and depreciation	**(126,855)**	(143,556)	(107,812)	**(528,002)**	(458,758)
Deferred taxes	**54,437**	6,883	(32,031)	**82,855**	47,728
Gain on business combination	**22,001**	-	-	**22,001**	-
Impairment	**-**	-	(131,623)	**(14,762)**	(274,623)
Net loss	**(4,032)**	(14,475)	(142,080)	**(160,051)**	(217,302)

The fluctuations in net income from period-to-period are caused by changes in both cash and non-cash based income and charges. Cash based items are reflected in fund flows from operations. Non-cash items include: equity based compensation expense, unrealized gains and losses on derivative instruments, unrealized foreign exchange gains and losses, accretion, depletion and depreciation expense, and deferred taxes. In addition, non-cash items may also include amounts resulting from business combinations or charges resulting from impairment or impairment reversals.

Equity based compensation

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under the Vermilion Incentive Plan ("VIP").

Equity based compensation in Q4 2016 increased as compared to Q3 2016 due to a revision of performance estimates. For the three months and year ended December 31, 2016, the decrease in equity based compensation is primarily due to the lower average grant value.

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 year ended December 31, 2016, we recognized an unrealized loss on derivative instruments of $138.0 million. This unrealized loss resulted from realizing gains on derivatives for contracts settled during the period, coupled with higher forward prices for European natural gas as at December 31, 2016. As at December 31, 2016, we have a net derivative liability position of $69.7 million.

Unrealized foreign exchange gain or loss

As a result of Vermilion's international operations, Vermilion has monetary assets and liabilities denominated in currencies other than the Canadian dollar. These monetary assets and liabilities include cash, receivables, payables, long-term debt, derivative instruments and intercompany loans, primarily denominated in the US dollar and Euro.

Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the functional currency of Vermilion and its subsidiaries. Unrealized foreign exchange primarily results from the translation of Euro denominated financial assets and US dollar denominated financial liabilities. As such, an appreciation in the Euro against the Canadian dollar will result in an unrealized foreign exchange gain while an appreciation in the US dollar against the Canadian dollar will result in an unrealized foreign exchange loss (and vice-versa).

For the three months ended December 31, 2016, the Canadian dollar weakened against the US dollar and strengthened against the Euro, resulting in an unrealized foreign exchange loss of $2.5 million. For the year ended December 31, 2016, the Canadian dollar strengthened more significantly against the Euro than the US dollar, resulting in an unrealized foreign exchange loss of $0.8 million.

Accretion

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

Depletion and depreciation

Depletion and depreciation expense is recognized to allocate the capitalized cost of extracting natural resources and the cost of material assets over the useful life of the respective assets. Fluctuations in depletion and depreciation expense are primarily the result of changes in produced crude oil and natural gas volumes.

Depletion and depreciation on a per boe basis for Q4 2016 of $22.42 was relatively consistent as compared to $23.69 in Q3 2016.

For the three months ended December 31, 2016, depletion and depreciation on a per boe basis of $22.42 was higher than $18.88 in the same period of 2015 due to production from Ireland. For the year ended December 31, 2016, depletion and depreciation on a per boe basis of $22.65 was relatively consistent with $22.98 in the same period of 2015 as increased production from Ireland was offset by increased production from our Mannville condensate-rich gas properties.

Deferred tax

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

Impairment

In 2015, as a result of declines in price forecasts for crude oil and Canadian natural gas, Vermilion recorded a non-cash impairment charge of $274.6 million ($219.8 million relating to capital assets and $54.8 million relating to E&E assets) in the Canada segment. The impairment charge related to the light crude oil play in Saskatchewan ($267.9 million based on a recoverable amount of $266.8 million) and shallow coal bed methane properties in Alberta ($6.7 million based on a recoverable amount of $19.7 million).

In the first quarter of 2016, as a result of declines in price forecasts for European natural gas, Vermilion recorded a non-cash impairment charge of $14.8 million (based on a recoverable amount of $737.3 million).

Gain on business combination

In December of 2016, we acquired, through a wholly-owned subsidiary, interests in production and exploration assets in Germany from Engie E&P Deutschland GmbH.

We recognized a non-cash gain on business combination of $22.0 million that resulted from the recognition of additional reserve value when the acquisition closed in December 2016, compared to the estimated value in June when Vermilion entered into a definitive purchase and sale agreement and the acquisition price was determined.

TAXES

Corporate income tax rates

Vermilion pays corporate income taxes in France, the Netherlands, and Australia. In addition, Vermilion pays PRRT in Australia. PRRT is a profit based tax applied at a rate of 40% on sales less operating expenses, capital expenditures, and other eligible expenditures. PRRT is deductible in the calculation of taxable income in Australia.

Taxable income was subject to corporate income tax at the following rates:

Jurisdiction	2016	2015
Canada [1]	27.0%	25.5% / 27.0%
France	34.4%	34.4%
Netherlands [2]	50.0%	50.0%
Germany	24.2%	24.2%
Ireland	25.0%	25.0%
Australia	30.0%	30.0%
United States	35.0%	35.0%

[1] Alberta corporate income tax rates increased from 10% to 12% effective July 1, 2015.

[2] In the Netherlands, an additional 10% uplift deduction is allowed against taxable income that is applied to operating expenses, eligible G&A and tax deductions for depletion and abandonment retirement obligations.

In 2012, the France government enacted a new 3% tax on dividend distributions made by entities subject to corporate income tax in France. The tax applies to any dividends paid on or after April 17, 2012 and is not recovered by any tax treaties or deductible for French corporate income tax purposes. In late December 2016, the French government passed legislation that will exempt any dividend distributions made by Vermilion after January 1, 2017 from the 3% tax. Vermilion did not pay any dividends from its French entities in 2016.

Tax pools

As at December 31, 2016, we had the following tax pools:

($M)	Oil & Gas Assets	Tax Losses	Other	Total
Canada	978,949 [1]	489,702 [5]	32,503	1,501,154
France	351,551 [2]	13,360 [6]	-	364,911
Netherlands	68,139 [3]	-	-	68,139
Germany	190,002 [3]	57,156 [7]	20,306	267,464
Ireland	942,129 [4]	403,779 [5]	-	1,345,908
Australia	276,911 [1]	-	-	276,911
United States	34,885 [1]	30,328 [5]	797	66,010
Total	2,842,566	994,325	53,606	3,890,497

[1] Deduction calculated using various declining balance rates

[2] Deduction calculated using a combination of straight-line over the assets life and unit of production method

[3] Deduction calculated using a unit of production method

[4] Deduction for current development expenditures and tax losses at 100% against taxable income

[5] Tax losses can be carried forward at 100% against taxable income

[6] Tax losses carried forward are available to offset the first Euro 1million of taxable income and 50% of taxable profits in excess each taxation year

[7] Tax losses carried forward are available to offset the first Euro 1million of taxable income and 60% of taxable profits in excess each taxations year

FINANCIAL POSITION REVIEW

Balance sheet strategy

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

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

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

Long-term debt

Our long-term debt as at December 31, 2016 consists entirely of borrowings against our revolving credit facility. We redeemed the senior unsecured notes that came due on February 10, 2016 using funds drawn against the revolving credit facility.

The balances recognized on our balance sheet are as follows:

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Revolving credit facility	**1,362,192**	1,162,998
Senior unsecured notes	**-**	224,901
Long-term debt	**1,362,192**	1,387,899

Revolving Credit Facility

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

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Total facility amount	**2,000,000**	2,000,000
Amount drawn	**(1,362,192)**	(1,162,998)
Letters of credit outstanding	**(20,100)**	(25,200)
Unutilized capacity	**617,708**	811,802

In addition, as at December 31, 2016, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	**Limit**	**Dec 31, 2016**	**Dec 31, 2015**
Consolidated total debt to consolidated EBITDA	4.0	**2.36**	2.23
Consolidated total senior debt to total capitalization	55%	**46%**	36%

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

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

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

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Long-term debt	**1,362,192**	1,162,998
Current liabilities [(1)]	**290,862**	503,731
Current assets	**(225,906)**	(284,778)
Net debt	**1,427,148**	1,381,951
Ratio of net debt to fund flows from operations	**2.8**	2.7

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

As at December 31, 2016, long term debt decreased to $1.36 billion (December 31, 2015 - $1.39 billion, including the current portion of long-term debt) as fund flows from operations generated in excess of capital expenditures, abandonment expenditures, acquisitions, and cash dividends was used to reduce debt. The decrease in long-term debt was coupled with working capital changes, such that net debt increased from $1.38 billion at December 31, 2015 to $1.43 billion at December 31, 2016. Weaker commodity prices versus the prior period decreased fund flows from operations, resulting in the ratio of net debt to fund flows from operations increasing slightly from 2.7 to 2.8.

Shareholders' capital
During the year ended December 31, 2016, we maintained monthly dividends at $0.215 per share and declared dividends which totalled $299.1 million.

The following table outlines our dividend payment history:

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

Our policy with respect to dividends is to be conservative and maintain a low ratio of dividends to fund flows from operations. During low commodity price cycles, we will initially maintain dividends and allow the ratio to rise. Should low commodity price cycles remain for an extended period of time, we will evaluate the necessity of changing the level of dividends, taking into consideration capital development requirements, debt levels, and acquisition opportunities.

In February of 2015, we amended our existing dividend reinvestment plan to include a Premium Dividend™ Component. The Premium Dividend™ Component, when combined with our continuing Dividend Reinvestment Component, increases our access to the lowest cost sources of equity capital available. While the Premium Dividend™ results in a modest amount of equity issuance, we believe it represents the most prudent approach to preserving near-term balance sheet strength. Both components of our program can be reduced or eliminated at the company's discretion, offering considerable flexibility.

As previously announced, we commenced proration of the Premium Dividend™ of our Dividend Reinvestment Plan by 25% beginning with our October dividend payment. Eligible shareholders who have elected to participate in the Premium Dividend™ component were then receiving the 1.5% premium on 75% of their participating shares and the regular cash dividend on the remaining 25% of their shares. We increased the proration factor by a further 25% beginning with the January 2017 dividend payment. Subject to unexpected changes in the commodity price outlook, we expect to continue to increase the proration by 25% per quarter during the first half of 2017, such that, by the beginning of the third quarter, there would be no further equity issuance under the Premium Dividend™ component of our Dividend Reinvestment Plan. We also reduced the discount associated with our traditional Dividend Reinvestment Plan from 3% to 2%, beginning with the January 2017 dividend payment.

Although we expect to be able to maintain our current dividend, fund flows from operations may not be sufficient during this low commodity price environment to fund cash dividends, capital expenditures, and asset retirement obligations. We will evaluate our ability to finance any shortfall with debt, issuances of equity, or by reducing some or all categories of expenditures to ensure that total expenditures do not exceed available funds.

The following table reconciles the change in shareholders' capital:

Shareholders' Capital	Number of Shares ('000s)	Amount ($M)
Balance as at December 31, 2015	111,991	2,181,089
Shares issued for the DRIP [(1)]	4,671	192,998
Vesting of equity based awards	1,320	67,146
Share-settled dividends on vested equity based awards	87	3,242
Shares issued for equity based compensation	194	8,247
Balance as at December 31, 2016	118,263	2,452,722

[(1)] DRIP Refers to Vermilion's Premium Dividend [TM] and Dividend Reinvestment Plan.

As at December 31, 2016, there were approximately 1.7 million VIP awards outstanding. As at February 24, 2017, there were approximately 118.7 million common shares issued and outstanding.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As at December 31, 2016, we had the following contractual obligations and commitments:

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt	-	1,335,600	-	-	1,335,600
Operating lease obligations	12,683	21,087	18,228	1,657	53,655
Ship or pay agreement relating to the Corrib project	4,241	7,331	6,074	31,427	49,073
Purchase obligations	9,007	3,852	7	-	12,866
Drilling and service agreements	5,437	9,850	20,511	26,870	62,668
Total contractual obligations and commitments	31,368	1,377,720	44,820	59,954	1,513,862

ASSET RETIREMENT OBLIGATIONS

As at December 31, 2016, asset retirement obligations were $525.0 million compared to $305.6 million as at December 31, 2015.

The increase in asset retirement obligations is largely attributable to an overall decrease in the discount rates applied to the abandonment obligation, additional obligations recognized on our acquisition in Germany, and accretion expense.

RISKS AND UNCERTAINTIES

Crude oil and natural gas exploration, production, acquisition and marketing operations involve a number of risks and uncertainties including financial risks and uncertainties. These include fluctuations in commodity prices, exchange rates and interest rates as well as uncertainties associated with reserve and resource volumes, sales volumes and government regulatory and income tax regime changes. These and other related risks and uncertainties are discussed in additional detail below.

Commodity prices
Our operational results and financial condition is dependent on the prices received for crude oil and natural gas production. Crude oil and natural gas prices have fluctuated significantly during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other crude oil and natural gas producing regions.

Exchange rates
Much of our revenue stream is priced in U.S. dollars and as such an increase in the strength of the Canadian dollar relative to the U.S. dollar may result in the receipt of fewer Canadian dollars with respect to our production. In addition, we incur expenses and capital costs in U.S. dollars, Euros and Australian dollars and accordingly, the Canadian dollar equivalent of these expenditures as reported in our financial results is impacted by the prevailing exchange rates at the time the transaction occurs. We monitor risks associated with exchange rates and, when appropriate, use derivative financial instruments to manage our exposure to these risks.

Production and sales volumes
The operation of crude oil and natural gas wells and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to us and possible liability to third parties. We maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected operations, to the extent that such insurance is commercially viable. We may become liable for damages arising from such events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities may materially impact our financial results.

Continuing production from a property, and to some extent the marketing of produced volumes, is largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat our claim to certain properties. Such circumstances could negatively affect our financial results.

An increase in operating costs or a decline in our production level could have an adverse effect on our financial results. The level of production may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues.

Interest rates
An increase in interest rates could result in a significant increase in the amount we pay to service debt.

Reserve volumes
Our reserve volumes and related reserve values support the carrying value of our crude oil and natural gas assets on the consolidated balance sheets and provide the basis to calculate the depletion of those assets. There are numerous uncertainties inherent in estimating quantities of reserves and future net revenues to be derived therefrom, including many factors beyond our control. These include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of crude oil, NGLs and natural gas, operating expenses, well abandonment and salvage values, royalties and any government levies that may be imposed over the producing life of the reserves. These assumptions were based on estimated prices in use at the date the evaluation was prepared, and many of these assumptions are subject to change and are beyond our control. Actual production and income derived therefrom will vary from these evaluations, and such variations could be material.

Asset retirement obligations
Our asset retirement obligations are based on environmental regulations and estimates of future costs and the timing of expenditures. Changes in environmental regulations, the estimated costs associated with reclamation activities and the related timing may impact our financial position and results of operations.

Government regulation and income tax regime
Our operations are governed by many levels of government, including municipal, state, provincial and federal governments, in Canada, France, the Netherlands, Australia, Germany, Ireland, Hungary, Croatia, Slovakia and the United States. We are subject to laws and regulations regarding environment, health and safety issues, lease interests, taxes and royalties, among others. Failure to comply with the applicable laws can result in significant increases in costs, penalties and even losses of operating licences. The regulatory process involved in each of the countries in which we operate is not uniform and regulatory regimes vary as to complexity, timeliness of access to, and response from, regulatory bodies and other matters specific to each jurisdiction. If regulatory approvals or permits are delayed or not obtained, there can also be delays or abandonment of projects and decreases in production and increases in costs, potentially resulting in us being unable to fully execute our strategy. Governments may also amend or create new legislation and regulatory bodies may also amend regulations or impose additional requirements which could result in increased capital, operating and compliance costs.

There can be no assurance that income tax laws and government incentive programs relating to the crude oil and natural gas industry in Canada and the foreign jurisdictions in which we operate, will not be changed in a manner which adversely affects the results of our operations.

A change in the royalty regime resulting in an increase in royalties would reduce our net earnings and could make future capital expenditures or our operations uneconomic and could, in the event of a material increase in royalties, make it more difficult to service and repay outstanding debt. Any material increase in royalties would also significantly reduce the value of the associated assets.

FINANCIAL RISK MANAGEMENT

To mitigate the aforementioned risks whenever possible, we seek to hire personnel with experience in specific areas. In addition, we provide continued training and development to staff to further develop their skills. When appropriate, we use third party consultants with relevant experience to augment our internal capabilities with respect to certain risks.

We consider our commodity price risk management program as a form of insurance that protects our cash flow and rate of return. The primary objective of the risk management program is to support our dividends and our internal capital development program. The level of commodity price risk management that occurs is highly dependent on the amount of debt that is carried. When debt levels are higher, we will be more active in protecting our cash flow stream through our commodity price risk management strategy.

When executing our commodity price risk management programs, we use derivative financial instruments encompassing over-the-counter financial structures as well as fixed/collar structures to economically hedge a part of our physical crude oil and natural gas production. We have strict controls and guidelines in relation to these activities and contract principally with counterparties that have investment grade credit ratings.

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, income and expenses, as well as 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 our consolidated financial statements or financial performance. Estimates are reviewed by management on an ongoing basis, and as a result, certain estimates 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 in which we operate, the critical accounting estimates may affect one or more jurisdictions.

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

- Asset retirement obligations: Asset retirement obligations are based on judgments regarding regulatory requirements, estimates of future costs, and the expected timing of expenditures. The carrying balance of asset retirement obligations and accretion expense may differ due to changes in: laws and regulations, technology, the expected timing of expenditures, and market conditions affecting the discount rate applied.
- Determination of CGUs: CGU determination is subject to management's judgment of the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The factors used by Vermilion to determine CGUs vary by jurisdiction due to their unique operating and geographic conditions. In general, Vermilion will assess the following factors: geographic proximity of the assets within a group to one another, geographic proximity of the group of assets to other groups of assets, homogeneity of the production from the group of assets and the sharing of infrastructure used to process and/or transport production. The composition of CGUs can directly impact the calculated recoverable amount of a CGU and the recorded impairment loss or recovery.
- Assessment of impairments or recovery of previous impairments: The calculation of the recoverable amount of a CGU is based on market factors and estimates of reserves and resources. Reserve and resource estimates are based on: engineering data, estimated future commodity prices, expected future rates of production, and assumptions regarding the timing and amount of future expenditures. Changes in these judgments, estimates and assumptions can directly impact the calculated recoverable amount of a CGU and the recorded impairment loss or recovery.
- Income Taxes: Tax interpretations, regulations, and legislation in the various jurisdictions in which Vermilion and its subsidiaries operate are subject to change and interpretation. Changes in laws and interpretations can affect the timing of the reversal of temporary tax differences, the tax rates in effect when such differences reverse and Vermilion's ability to use tax losses and other tax pools in the future. The Company's income tax filings are subject to audit by taxation authorities in numerous jurisdictions and the results of such audits may increase or decrease the tax liability. The determination of tax amounts recognized in the consolidated financial statements are based on management's assessment of the tax positions, which includes consideration of their technical merits, communications with tax authorities and management's view of the most likely outcome.

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 December 31, 2016.

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

ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

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

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

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

In the adoption of IFRS 15, Vermilion has in place a transition team that will perform a detailed review of the Company's standard contracts with customers in accordance with the issued IFRS.

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

HEALTH, SAFETY AND ENVIRONMENT

We are committed to ensuring we conduct our activities in a manner that will protect the health and safety of our employees, contractors, and the public. Our health, safety, and environment ("HSE") vision is to fully integrate health, safety, and environment into our business, where our culture is recognized as a model by industry and stakeholders, resulting in a safe and healthy workplace. Our mantra is HSE: Everywhere. Everyday. Everyone.

We maintain health, safety and environmental practices and procedures in compliance with or exceeding regulatory requirements and industry standards. All of our personnel are expected to work safely and in accordance with established regulations and procedures, and we seek to keep our people safe and to reduce impacts to land, water and air. During 2016 we:

- Maintained clear priorities around 5 key focus areas of HSE Culture, Communication and Knowledge Management, Technical Safety Management, Incident Prevention and Operational Stewardship & Sustainability;
- Completed and published our Corporate Sustainability Report;
- Reported our CO_2e emissions to the Carbon Disclosure Project, achieving a position on the Climate "A" list. One of only 5 oil and gas companies world-wide to achieve this ranking.
- Completed a corporate wide HSE perception survey to monitor program progress and verify plan forward;
- Emphasized improving energy efficiency, greenhouse gas emissions reduction and water efficiency optimization;
- Further refined and expanded our enterprise wide corporate risk register;
- Developed and delivered a robust organization-wide HSE leadership training program to improve hazard identification and risk reduction;
- Maintained focus on our recently developed risk mitigation program around our top fatal risk and energy type exposures;
- Continued development of a robust hazard identification and risk mitigation program specific to environmentally sensitive areas;
- Implemented our Corporate Process Hazards Analysis Standard in support of our focus on process safety;
- Initiated the development of our Corporate Process Safety Management System;
- Further progressed our Asset Integrity Management System;
- Completed a comprehensive review of our Management of Change procedures across the organization;
- Reduced long-term environmental liabilities through decommissioning, abandoning and reclaiming well leases and facilities;
- Performed auditing, management inspections and workforce observations to identify potential hazards and apply risk reduction measures;
- Developed, communicated and measured against leading and lagging HSE key performance indicators;
- Further enhanced of our competency and training programs;
- Managed our waste products by reducing, recycling and recovering; and
- Continued risk management efforts in addition to detailed emergency-response planning.

We are a member of several organizations concerned with environment, health and safety, including numerous regional co-operatives and synergy groups. In the area of stakeholder relations, we work to build long-term relationships with environmental stakeholders and communities.

SUSTAINABILITY

As a responsible oil and gas producer, we consistently seek to deliver long-term shareholder value by operating in an economically, environmentally and socially sustainable manner that is recognized as a model in our industry.

Vermilion regularly communicates with its stakeholders, including shareholders and potential investors, and we continually monitor trends and best practices in stakeholder engagement. Reporting on sustainability, or corporate social responsibility, is an increasingly important way to reflect Company performance for shareholders and potential investors. As a result, Vermilion published its first sustainability report in August 2014, in compliance with the comprehensive option of the Global Reporting Initiative's G4 reporting framework. We continue to report on this basis annually, as it provides an opportunity to share how we identify our economic, environmental and social impacts, integrate their associated opportunities and risks into our business strategies, and chart our progress.

Our stakeholders expect us to deliver strong financial results in a responsible and ethical way. Reflecting this, we strive to operate in a manner that protects the health and safety of our staff and communities, provides responsible stewardship over the environment, and treats staff, contractors, partners and suppliers respectfully and fairly.

As a result, we align expectations for economic success with the elements of our sustainability commitments, leading us to prioritize our objectives as follows:

- The safety and health of our staff and those involved directly or indirectly in our operations.
- Our responsibility to protect the environment. We follow the Precautionary Principle introduced in 1992 by the United Nations "Rio Declaration on Environment and Development" by using environmental risk as part of our development decision criteria, and by continually seeking improved environmental performance in our operations.
- Economic success through a focus on operational excellence across our business, which includes technical and process excellence, efficiency, expertise and stakeholder relations.
- Vermilion's sustainability performance has earned consistently higher rankings. In 2016, Corporate Knights ranked Vermilion 9 th in their Future 40 listing, up from 15th in 2015 and 32nd in 2014.

CORPORATE GOVERNANCE

We are committed to a high standard of corporate governance practices, a dedication that begins at the Board level and extends throughout the Company. We believe good corporate governance is in the best interest of our shareholders, and that successful companies are those that deliver growth and a competitive return along with a commitment to the environment, to the communities where they operate and to their employees.

We comply with the objectives and guidelines relating to corporate governance adopted by the Canadian Securities Administrators and the Toronto Stock Exchange. In addition, the Board monitors and considers the implementation of corporate governance standards proposed by various regulatory and non-regulatory authorities in Canada. A discussion of corporate governance policies is included each year in our proxy materials for our annual general meeting of shareholders, copies of which are available on SEDAR (www.sedar.com).

A summary of the significant differences between the governance practices of the Company and those required of U.S. domestic companies under the New York Stock Exchange listing standards can be found in the Governance section of the Company's website at *http://www.vermilionenergy.com/about/governance.cfm*.

DISCLOSURE CONTROLS AND PROCEDURES

Our officers have established and maintained disclosure controls and procedures and evaluated the effectiveness of these controls in conjunction with our filings.

As of December 31, 2016, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

INTERNAL CONTROL OVER FINANCIAL REPORTING

A company's internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

The Chief Executive Officer and the Chief Financial Officer of Vermilion have assessed the effectiveness of Vermilion's internal control over financial reporting as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. The assessment was based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Chief Executive Officer and the Chief Financial Officer of Vermilion have concluded that Vermilion's internal control over financial reporting was effective as of December 31, 2016. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2016 has been audited by Deloitte LLP, as reflected in their report included in the 2016 audited annual financial statements filed with the US Securities and Exchange Commission. No changes were made to Vermilion's internal control over financial reporting during the year ended December 31, 2016, that have materially affected, or are reasonably likely to materially affect, the internal controls 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 December 31, 2016			Year Ended December 31, 2016			Three Months Ended Dec 31, 2015	Year Ended Dec 31, 2015
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	51.77	3.05	**33.48**	43.58	2.14	**26.81**	28.94	34.32
Royalties	(6.17)	(0.22)	**(3.51)**	(4.37)	(0.09)	**(2.28)**	(2.80)	(3.01)
Transportation	(2.34)	(0.18)	**(1.66)**	(2.36)	(0.17)	**(1.63)**	(1.48)	(1.75)
Operating	(9.49)	(1.32)	**(8.62)**	(8.05)	(1.20)	**(7.59)**	(9.62)	(9.54)
Operating netback	33.77	1.33	**19.69**	28.80	0.68	**15.31**	15.04	20.02
General and administration			**(0.97)**			**(1.25)**	(1.44)	(1.81)
Fund flows from operations netback			**18.72**			**14.06**	13.60	18.21
France								
Sales	63.99	1.55	**63.71**	55.42	1.59	**55.15**	54.20	62.67
Royalties	(5.95)	(0.36)	**(5.93)**	(6.08)	(0.34)	**(6.05)**	(6.15)	(6.00)
Transportation	(3.55)	-	**(3.53)**	(3.32)	-	**(3.30)**	(3.65)	(3.42)
Operating	(10.13)	(3.12)	**(10.17)**	(11.15)	(2.51)	**(11.17)**	(13.50)	(11.30)
Operating netback	44.36	(1.93)	**44.08**	34.87	(1.26)	**34.63**	30.90	41.95
General and administration			**(4.52)**			**(4.27)**	(4.18)	(4.50)
Other income			**3.39**			**0.85**	-	7.08
Current income taxes			**(2.54)**			**(0.64)**	3.87	(5.29)
Fund flows from operations netback			**40.41**			**30.57**	30.59	39.24
Netherlands								
Sales	63.18	6.78	**40.84**	44.93	5.67	**34.15**	42.61	46.77
Royalties	-	(0.08)	**(0.46)**	-	(0.08)	**(0.50)**	(0.26)	(1.12)
Operating	-	(1.49)	**(8.90)**	-	(1.19)	**(7.05)**	(7.17)	(8.24)
Operating netback	63.18	5.21	**31.48**	44.93	4.40	**26.60**	35.18	37.41
General and administration			**(0.26)**			**(0.52)**	(0.93)	(1.51)
Current income taxes			**0.16**			**(2.25)**	(3.35)	(4.40)
Fund flows from operations netback			**31.38**			**23.83**	30.90	31.50
Germany								
Sales	-	6.09	**36.54**	-	5.33	**31.97**	39.68	43.10
Royalties	-	(0.01)	**(0.06)**	-	(0.38)	**(2.30)**	(4.70)	(6.75)
Transportation	-	(0.28)	**(1.65)**	-	(0.53)	**(3.16)**	(2.05)	(3.41)
Operating	-	(2.91)	**(17.44)**	-	(2.27)	**(13.62)**	(19.31)	(11.41)
Operating netback	-	2.89	**17.39**	-	2.15	**12.89**	13.62	21.53
General and administration			**(7.73)**			**(9.15)**	(12.22)	(7.69)
Fund flows from operations netback			**9.66**			**3.74**	1.40	13.84
Ireland								
Sales	-	7.38	**44.29**	-	5.86	**35.16**	-	-
Transportation	-	(0.29)	**(1.77)**	-	(0.35)	**(2.09)**	-	-
Operating	-	(0.89)	**(5.34)**	-	(1.00)	**(6.01)**	-	-
Operating netback	-	6.20	**37.18**	-	4.51	**27.06**	-	-
General and administration			**(1.58)**			**(1.54)**	-	-
Fund flows from operations netback			**35.60**			**25.52**	-	-
Australia								
Sales	69.05	-	**69.05**	60.33	-	**60.33**	58.74	70.22
Operating	(26.83)	-	**(26.83)**	(20.95)	-	**(20.95)**	(17.08)	(22.29)
PRRT [(1)]	(2.82)	-	**(2.82)**	(0.69)	-	**(0.69)**	(1.29)	(2.97)
Operating netback	39.40	-	**39.40**	38.69	-	**38.69**	40.37	44.96
General and administration			**(3.60)**			**(2.82)**	(2.17)	(2.48)
Corporate income taxes			**(4.87)**			**(3.32)**	1.47	(3.12)
Fund flows from operations netback			**30.93**			**32.55**	39.67	39.36

	Three Months Ended December 31, 2016			Year Ended December 31, 2016			Three Months Ended Dec 31, 2015	Year Ended Dec 31, 2015
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/bbl	Total $/boe
United States								
Sales	56.77	1.93	**53.58**	46.89	0.85	**43.70**	41.94	47.53
Royalties	(16.49)	(1.72)	**(16.05)**	(13.71)	(0.62)	**(12.95)**	(12.40)	(13.93)
Operating	(8.51)	-	**(7.91)**	(8.50)	-	**(7.85)**	(6.11)	(8.23)
Operating netback	31.77	0.21	**29.62**	24.68	0.23	**22.90**	23.43	25.37
General and administration			**(23.02)**			**(21.65)**	(20.18)	(42.51)
Fund flows from operations netback			**6.60**			**1.25**	3.25	(17.14)
Total Company								
Sales	60.58	5.47	**45.93**	51.73	4.18	**37.88**	41.04	47.07
Realized hedging gain	0.45	0.04	**0.34**	1.45	0.68	**2.81**	3.71	2.07
Royalties	(4.92)	(0.10)	**(2.65)**	(4.28)	(0.09)	**(2.33)**	(2.85)	(3.30)
Transportation	(2.33)	(0.19)	**(1.69)**	(2.22)	(0.20)	**(1.70)**	(1.78)	(2.09)
Operating	(13.33)	(1.34)	**(10.54)**	(11.88)	(1.23)	**(9.53)**	(11.50)	(11.32)
PRRT [1]	(0.59)	-	**(0.28)**	(0.14)	-	**(0.07)**	(0.18)	(0.34)
Operating netback	39.86	3.88	**31.11**	34.66	3.34	**27.06**	28.44	32.09
General and administration			**(2.03)**			**(2.27)**	(2.18)	(2.68)
Interest expense			**(2.55)**			**(2.44)**	(2.90)	(3.00)
Realized foreign exchange gain (loss)			**0.23**			**0.17**	(0.04)	0.03
Other income			**0.70**			**0.17**	0.04	1.64
Corporate income taxes [1]			**(1.03)**			**(0.78)**	0.55	(2.22)
Fund flows from operations netback			**26.43**			**21.91**	23.91	25.86

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

Supplemental Table 2: Hedges

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

The following tables outline Vermilion's outstanding risk management positions as at December 31, 2016:

Crude Oil	Period	Exercise date[1]	Currency	Bought Put Volume (bbl/d)	Weighted Average Bought Put Price / bbl	Sold Call Volume (bbl/d)	Weighted Average Sold Call Price / bbl	Sold Put Volume (bbl/d)	Weighted Average Sold Put Price / bbl	Swap Volume (bbl/d)	Weighted Average Swap Price / bbl	Additional Swap Volume (mmbtu/d) [2]
Dated Brent												
3-Way Collar	Oct 2016 - Mar 2017		USD	500	50.00	500	60.00	500	42.50	-	-	-
3-Way Collar	Jan 2017 - Dec 2017		USD	2,500	51.00	2,500	60.50	2,500	41.50	-	-	-
3-Way Collar	Jul 2017 - Jun 2018		USD	2,000	55.00	2,000	64.06	2,000	45.00	-	-	-
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	1,250	55.50	-
Swaption	Jul 2017 - Jun 2018	Mar 31, 2017	USD	-	-	-	-	-	-	500	60.00	-
Swaption	Jul 2017 - Jun 2018	Jun 30, 2017	USD	-	-	-	-	-	-	1,000	60.00	-
WTI												
3-Way Collar	Jan 2017 - Dec 2017		CAD	1,500	70.00	1,500	75.00	1,500	55.00	-	-	-
3-Way Collar	Jan 2017 - Mar 2017		USD	2,500	50.00	2,500	55.00	2,500	42.50	-	-	-
3-Way Collar	Jul 2017 - Dec 2017		USD	1,500	53.67	1,500	63.00	1,500	45.00	-	-	-
Swap	Jan 2017 - Mar 2017		USD	-	-	-	-	-	-	2,500	53.10	-

North American Gas	Period	Exercise date[1]	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap Price / mmbtu	Additional Swap Volume (mmbtu/d) [2]
AECO												
Collar	Nov 2016 - Oct 2017		CAD	7,109	2.18	9,478	2.86	-	-	-	-	-
Collar	Nov 2016 - Dec 2017		CAD	9,478	2.33	9,478	3.02	-	-	-	-	-
Collar	Jan 2017 - Dec 2017		CAD	4,739	2.37	4,739	3.25	-	-	-	-	-
Swap	Nov 2016 - Dec 2017		CAD	-	-	-	-	-	-	2,370	2.99	-
Swap	Jan 2017 - Mar 2017		CAD	-	-	-	-	-	-	7,109	3.35	-
Swap	Jan 2017 - Dec 2017		CAD	-	-	-	-	-	-	7,109	2.94	-
Swap	Apr 2017 - Oct 2017		CAD	-	-	-	-	-	-	7,109	3.01	-
Swap	Nov 2017 - Dec 2017		CAD	-	-	-	-	-	-	7,109	3.35	-
AECO Basis												
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	5,000	(0.75)	-
Swap	Jan 2018 - Dec 2018		USD	-	-	-	-	-	-	10,000	(0.83)	-
NYMEX												
Swap	Jan 2017 - Dec 2017		USD	-	-	-	-	-	-	5,000	3.00	-

European Gas	Period	Exercise date[1]	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap price / mmbtu	Additional Swap Volume (mmbtu/d) [2]
NBP												
Collar	Apr 2016 - Mar 2017		GBP	2,500	4.00	2,500	4.77	-	-	-	-	-
Collar	Oct 2016 - Mar 2017		GBP	2,500	3.30	5,000	3.72	-	-	-	-	-
Collar	Oct 2016 - Sep 2017		GBP	5,000	3.25	10,000	4.03	-	-	-	-	-
Collar	Oct 2016 - Dec 2017		GBP	5,000	3.25	10,000	4.07	-	-	-	-	-
Collar	Jan 2017 - Dec 2017		GBP	5,000	3.30	7,500	3.77	-	-	-	-	-
Collar	Jan 2018 - Dec 2018		GBP	2,500	3.15	2,500	3.82	-	-	-	-	-
Put	Dec 2016 - Feb 2017		GBP	20,000	4.00	-	-	-	-	-	-	-
Call	Oct 2016 - Mar 2017		GBP	-	-	2,500	4.90	-	-	-	-	-
Swap	Jan 2017 - Dec 2017		GBP	-	-	-	-	-	-	2,500	4.22	2,500
Swap	Apr 2017 - Mar 2018		GBP	-	-	-	-	-	-	5,300	4.20	-
Swap	Jul 2017 - Dec 2017		GBP	-	-	-	-	-	-	2,500	3.95	-
Swap	Jan 2018 - Dec 2018		GBP	-	-	-	-	-	-	2,500	4.04	5,000
Swap	Jul 2016 - Mar 2017		EUR	-	-	-	-	-	-	2,457	5.73	-

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a swap with Vermilion at the above detailed terms.

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

European Gas	Period	Exercise date[1]	Currency	Bought Put Volume (mmbtu/d)	Weighted Average Bought Put Price / mmbtu	Sold Call Volume (mmbtu/d)	Weighted Average Sold Call Price / mmbtu	Sold Put Volume (mmbtu/d)	Weighted Average Sold Put Price / mmbtu	Swap Volume (mmbtu/d)	Weighted Average Swap price / mmbtu	Additional Swap Volume (mmbtu/d) [2]
TTF												
3-Way Collar	Apr 2017 - Sep 2017		EUR	9,827	4.18	9,827	5.06	9,827	3.08	-	-	-
3-Way Collar	Oct 2017 - Dec 2019		EUR	7,370	4.59	7,370	5.42	7,370	2.93	-	-	-
3-Way Collar	Jan 2018 - Dec 2018		EUR	9,827	4.67	9,827	5.42	9,827	3.22	-	-	-
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	3.13	-	-	-
Collar	Apr 2016 - Mar 2017		EUR	4,913	5.57	9,827	6.70	-	-	-	-	-
Collar	Jul 2016 - Mar 2017		EUR	2,457	5.35	4,913	6.92	-	-	-	-	-
Collar	Jul 2016 - Mar 2018		EUR	2,457	5.61	4,913	6.90	-	-	-	-	-
Collar	Oct 2016 - Dec 2017		EUR	2,457	5.28	2,457	6.21	-	-	-	-	-
Collar	Jan 2017 - Dec 2017		EUR	9,827	5.06	22,111	6.37	-	-	-	-	-
Collar	Apr 2017 - Sept 2017		EUR	2,457	3.81	4,913	4.47	-	-	-	-	-
Collar	Jan 2018 - Dec 2018		EUR	4,913	4.40	4,913	5.31	-	-	-	-	-
Call	Oct 2016 - Mar 2017		EUR	-	-	2,457	6.36	-	-	-	-	-
Swap	Jul 2016 - Jun 2018		EUR	-	-	-	-	-	-	2,559	5.89	-
Swap	Jan 2017 - Dec 2017		EUR	-	-	-	-	-	-	2,457	5.32	2,457
Swap	Oct 2017 - Dec 2018		EUR	-	-	-	-	-	-	17,197	4.80	-
Swap	Oct 2017 - Dec 2019		EUR	-	-	-	-	-	-	7,370	4.87	-
Swap	Jan 2018 - Dec 2019		EUR	-	-	-	-	-	-	1,228	5.00	-
Swap	Jan 2019 - Dec 2019		EUR	-	-	-	-	-	-	2,457	4.92	-
Put Spread	Apr 2017 - Sep 2017		EUR	14,740	4.40	-	-	14,740	3.15	-	-	-
Swaption	Apr 2017 - Jun 2018	Mar 31, 2017	EUR	-	-	-	-	-	-	4,913	4.55	-

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

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

Cross Currency Interest Rate		Receive Notional amount (USD)	Rate (US%)	Pay Notional amount (CAD)	Rate (CAD%)
Swap	Jan 2017 - Feb 2017	891,088,800	3.52	1,195,800,000	3.17

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a swap with Vermilion at the above detailed terms.

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

(3) In January 2017, Vermilion repaid $1.2 billion of borrowings on the revolving credit facility bearing interest at CDOR plus applicable margins and simultaneously borrowed US $0.9 billion on the revolving credit facility bearing interest at LIBOR plus applicable margins.

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Three Months Ended Dec 31, 2016	Sep 30, 2016	Dec 31, 2015	Year Ended Dec 31, 2016	Dec 31, 2015
Drilling and development	**66,437**	41,039	128,996	**241,545**	486,861
Exploration and evaluation	**445**	-	-	**863**	-
Capital expenditures	**66,882**	41,039	128,996	**242,408**	486,861
Property acquisition	**78,713**	10,391	6,227	**98,524**	28,897
Acquisitions	**78,713**	10,391	6,227	**98,524**	28,897

By category ($M)	Three Months Ended Dec 31, 2016	Sep 30, 2016	Dec 31, 2015	Year Ended Dec 31, 2016	Dec 31, 2015
Land	**59**	(36)	819	**1,555**	3,793
Seismic	**1,757**	1,110	4,217	**10,458**	8,243
Drilling and completion	**38,233**	18,694	58,327	**121,322**	212,358
Production equipment and facilities	**26,768**	18,046	55,662	**86,664**	218,963
Recompletions	**3,293**	603	6,338	**8,262**	26,689
Other	**(3,228)**	2,622	3,633	**14,147**	16,815
Capital expenditures	**66,882**	41,039	128,996	**242,408**	486,861
Acquisitions	**78,713**	10,391	6,227	**98,524**	28,897
Total capital expenditures and acquisitions	**145,595**	51,430	135,223	**340,932**	515,758

By country ($M)	Three Months Ended Dec 31, 2016	Sep 30, 2016	Dec 31, 2015	Year Ended Dec 31, 2016	Dec 31, 2015
Canada	**18,273**	20,801	33,723	**76,015**	216,158
France	**31,127**	11,110	24,164	**68,472**	92,582
Netherlands	**33,996**	6,441	18,810	**51,999**	47,325
Germany	**50,071**	978	(441)	**52,180**	5,363
Ireland	**1,711**	2,416	12,493	**9,375**	66,409
Australia	**5,236**	6,908	40,852	**59,910**	61,741
United States	**4,414**	2,776	5,622	**19,474**	25,014
Corporate	**767**	-	-	**3,507**	1,166
Total capital expenditures and acquisitions	**145,595**	51,430	135,223	**340,932**	515,758

Supplemental Table 4: Production

	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14
Canada												
Crude oil & condensate (bbls/d)	**7,945**	8,984	9,453	10,317	10,413	11,030	11,843	12,163	12,681	12,755	14,108	10,390
NGLs (bbls/d)	**2,444**	2,448	2,687	2,633	2,710	2,678	2,094	1,706	1,444	1,005	1,364	1,118
Natural gas (mmcf/d)	**75.12**	77.62	87.44	97.16	87.90	71.94	64.66	61.78	58.36	57.07	57.59	49.53
Total (boe/d)	**22,910**	24,368	26,713	29,141	27,773	25,698	24,713	24,165	23,851	23,272	25,070	19,763
% of consolidated	**38%**	37%	42%	44%	45%	47%	48%	48%	49%	47%	49%	42%
France												
Crude oil (bbls/d)	**11,220**	11,827	12,326	12,220	12,537	12,310	12,746	11,463	11,133	11,111	11,025	10,771
Natural gas (mmcf/d)	**0.38**	0.42	0.54	0.44	1.36	1.47	1.03	-	-	-	-	-
Total (boe/d)	**11,283**	11,897	12,416	12,293	12,763	12,555	12,917	11,463	11,133	11,111	11,025	10,771
% of consolidated	**19%**	19%	19%	19%	21%	22%	25%	23%	22%	22%	21%	23%
Netherlands												
Condensate (bbls/d)	**57**	86	96	114	110	109	112	63	81	63	96	69
Natural gas (mmcf/d)	**41.15**	47.62	49.18	53.40	56.34	53.56	32.43	36.41	31.35	38.07	40.35	43.15
Total (boe/d)	**6,915**	8,023	8,293	9,015	9,500	9,035	5,517	6,132	5,306	6,407	6,822	7,260
% of consolidated	**11%**	13%	13%	14%	16%	16%	11%	12%	11%	13%	13%	16%
Germany												
Natural gas (mmcf/d)	**14.80**	14.52	14.31	15.96	16.17	14.00	16.18	16.80	17.71	15.38	16.13	10.64
Total (boe/d)	**2,467**	2,420	2,385	2,660	2,695	2,333	2,696	2,801	2,952	2,563	2,689	1,773
% of consolidated	**4%**	4%	4%	4%	4%	4%	5%	6%	6%	5%	5%	4%
Ireland												
Natural gas (mmcf/d)	**62.92**	59.28	47.26	33.90	0.12	-	-	-	-	-	-	-
Total (boe/d)	**10,486**	9,879	7,877	5,650	20	-	-	-	-	-	-	-
% of consolidated	**17%**	16%	12%	9%	-	-	-	-	-	-	-	-
Australia												
Crude oil (bbls/d)	**6,388**	6,562	6,083	6,180	7,824	6,433	5,865	5,672	6,134	6,567	6,483	7,110
% of consolidated	**10%**	10%	9%	9%	13%	11%	11%	11%	12%	13%	12%	15%
United States												
Crude oil (bbls/d)	**362**	383	458	368	420	226	123	153	195	-	-	-
NGLs (bbls/d)	**23**	30	26	39	29	-	-	-	-	-	-	-
Natural gas (mmcf/d)	**0.18**	0.20	0.20	0.26	0.20	-	-	-	-	-	-	-
Total (boe/d)	**414**	447	518	450	483	226	123	153	195	-	-	-
% of consolidated	**1%**	1%	1%	1%	1%	-	-	-	-	-	-	-
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	**28,439**	30,320	31,129	31,871	34,043	32,786	32,783	31,220	31,668	31,501	33,076	29,458
% of consolidated	**47%**	48%	48%	49%	56%	58%	63%	62%	64%	63%	63%	63%
Natural gas (mmcf/d)	**194.54**	199.65	198.93	201.11	162.09	140.97	114.29	115.00	107.42	110.52	114.08	103.32
% of consolidated	**53%**	52%	52%	51%	44%	42%	37%	38%	36%	37%	37%	37%
Total (boe/d)	**60,863**	63,596	64,285	65,389	61,058	56,280	51,831	50,386	49,571	49,920	52,089	46,677

	2016	2015	2014	2013	2012	2011
Canada						
Crude oil & condensate (bbls/d)	**9,171**	11,357	12,491	8,387	7,659	4,701
NGLs (bbls/d)	**2,552**	2,301	1,233	1,666	1,232	1,297
Natural gas (mmcf/d)	**84.29**	71.65	55.67	42.39	37.50	43.38
Total (boe/d)	**25,771**	25,598	23,001	17,117	15,142	13,227
% of consolidated	**40%**	46%	47%	41%	40%	38%
France						
Crude oil (bbls/d)	**11,896**	12,267	11,011	10,873	9,952	8,110
Natural gas (mmcf/d)	**0.44**	0.97	-	3.40	3.59	0.95
Total (boe/d)	**11,970**	12,429	11,011	11,440	10,550	8,269
% of consolidated	**19%**	23%	22%	28%	28%	23%
Netherlands						
Condensate (bbls/d)	**88**	99	77	64	67	58
Natural gas (mmcf/d)	**47.82**	44.76	38.20	35.42	34.11	32.88
Total (boe/d)	**8,058**	7,559	6,443	5,967	5,751	5,538
% of consolidated	**13%**	14%	13%	15%	15%	16%
Germany						
Natural gas (mmcf/d)	**14.90**	15.78	14.99	-	-	-
Total (boe/d)	**2,483**	2,630	2,498	-	-	-
% of consolidated	**4%**	5%	5%	-	-	-
Ireland						
Natural gas (mmcf/d)	**50.89**	0.03	-	-	-	-
Total (boe/d)	**8,482**	5	-	-	-	-
% of consolidated	**13%**	-	-	-	-	-
Australia						
Crude oil (bbls/d)	**6,304**	6,454	6,571	6,481	6,360	8,168
% of consolidated	**10%**	12%	13%	16%	17%	23%
United States						
Crude oil (bbls/d)	**393**	231	49	-	-	-
NGLs (bbls/d)	**29**	7	-	-	-	-
Natural gas (mmcf/d)	**0.21**	0.05	-	-	-	-
Total (boe/d)	**457**	247	49	-	-	-
% of consolidated	**1%**	-	-	-	-	-
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	**30,433**	32,716	31,432	27,471	25,270	22,334
% of consolidated	**48%**	60%	63%	67%	67%	63%
Natural gas (mmcf/d)	**198.55**	133.24	108.85	81.21	75.20	77.21
% of consolidated	**52%**	40%	37%	33%	33%	37%
Total (boe/d)	**63,526**	54,922	49,573	41,005	37,803	35,202

Supplemental Table 5: Segmented Financial Results

	Three Months Ended December 31, 2016								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Drilling and development	16,895	31,127	5,737	1,694	1,711	5,236	4,037	-	66,437
Exploration and evaluation	-	-	-	-	-	-	-	445	445
Oil and gas sales to external customers	70,573	71,926	25,978	8,294	42,727	38,352	2,041	-	259,891
Royalties	(7,390)	(6,692)	(294)	(12)	-	-	(611)	-	(14,999)
Revenue from external customers	63,183	65,234	25,684	8,282	42,727	38,352	1,430	-	244,892
Transportation	(3,504)	(3,983)	-	(375)	(1,703)	-	-	-	(9,565)
Operating	(18,161)	(11,482)	(5,660)	(3,959)	(5,148)	(14,905)	(301)	-	(59,616)
General and administration	(2,035)	(5,101)	(162)	(1,755)	(1,523)	(1,998)	(877)	1,987	(11,464)
PRRT	-	-	-	-	-	(1,568)	-	-	(1,568)
Corporate income taxes	-	(2,867)	100	-	-	(2,703)	-	(370)	(5,840)
Interest expense	-	-	-	-	-	-	-	(14,410)	(14,410)
Realized gain on derivative instruments	-	-	-	-	-	-	-	1,920	1,920
Realized foreign exchange gain	-	-	-	-	-	-	-	1,291	1,291
Realized other income	-	3,822	-	-	-	-	-	120	3,942
Fund flows from operations	39,483	45,623	19,962	2,193	34,353	17,178	252	(9,462)	149,582

	Year Ended December 31, 2016								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,522,243	835,141	220,350	292,885	756,893	267,183	61,195	131,294	4,087,184
Drilling and development	62,706	68,472	23,740	3,803	9,375	59,910	13,539	-	241,545
Exploration and evaluation	-	-	-	-	-	-	-	863	863
Oil and gas sales to external customers	252,867	246,863	100,707	29,049	109,156	136,835	7,314	-	882,791
Royalties	(21,475)	(27,091)	(1,462)	(2,089)	-	-	(2,167)	-	(54,284)
Revenue from external customers	231,392	219,772	99,245	26,960	109,156	136,835	5,147	-	828,507
Transportation	(15,392)	(14,758)	-	(2,869)	(6,492)	-	-	-	(39,511)
Operating	(71,543)	(50,000)	(20,796)	(12,379)	(18,646)	(47,507)	(1,314)	-	(222,185)
General and administration	(11,826)	(19,101)	(1,525)	(8,314)	(4,772)	(6,400)	(3,624)	2,733	(52,829)
PRRT	-	-	-	-	-	(1,568)	-	-	(1,568)
Corporate income taxes	-	(2,867)	(6,624)	-	-	(7,522)	-	(1,097)	(18,110)
Interest expense	-	-	-	-	-	-	-	(56,957)	(56,957)
Realized gain on derivative instruments	-	-	-	-	-	-	-	65,376	65,376
Realized foreign exchange gain	-	-	-	-	-	-	-	4,041	4,041
Realized other income	-	3,822	-	-	-	-	-	205	4,027
Fund flows from operations	132,631	136,868	70,300	3,398	79,246	73,838	209	14,301	510,791

NON-GAAP FINANCIAL MEASURES

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

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

Capital expenditures: The sum of drilling and development and exploration and evaluation from the Consolidated Statement of Cash Flows. We consider capital expenditures to be a useful measure of our investment in our existing asset base. Capital expenditures are also referred to as E&D capital.

Cash dividends per share: Represents cash dividends declared per share and is a useful measure of the dividends a common shareholder was entitled to during the period.

Covenants: The financial covenants on our revolving credit facility contain non-GAAP measures. The definitions for these financial covenants are included in FINANCIAL POSITION REVIEW.

Diluted shares outstanding: The sum of shares outstanding at the period end plus outstanding awards under the VIP, based on current estimates of future performance factors and forfeiture rates.

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

Fund flows from operations per basic and diluted share: Management assesses fund flows from operations on a per share basis as we believe this provides a measure of our operating performance after taking into account the issuance and potential future issuance of Vermilion common shares. Fund flows from operations per basic share is calculated by dividing fund flows from operations by the basic weighted average shares outstanding as defined under IFRS. Fund flows from operations per diluted share is calculated by dividing fund flows from operations by the sum of basic weighted average shares outstanding and incremental shares issuable under the VIP as determined using the treasury stock method.

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

Operating netback: Sales less royalties, operating expense, transportation costs, PRRT, and realized hedging gains and losses presented on a per unit basis. Management assesses operating netback as a measure of the profitability and efficiency of our field operations. In contrast, fund flows from operations netback also includes general and administration expense, corporate income taxes and interest. Fund flows from operations netback is used by management to assess the profitability of our business units and Vermilion as a whole.

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

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

	Three Months Ended			Year Ended	
($M)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**	**Dec 31, 2016**	**Dec 31, 2015**
Dividends declared	**76,096**	75,465	71,965	**299,070**	283,575
Shares issued for the DRIP [(1)]	**(43,580)**	(50,912)	(46,764)	**(192,998)**	(155,033)
Net dividends	**32,516**	24,553	25,201	**106,072**	128,542
Drilling and development	**66,437**	41,039	128,996	**241,545**	486,861
Exploration and evaluation	**445**	-	-	**863**	-
Asset retirement obligations settled	**3,327**	2,066	4,921	**9,617**	11,369
Payout	**102,725**	67,658	159,118	**358,097**	626,772

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

	As at		
('000s of shares)	**Dec 31, 2016**	**Sep 30, 2016**	**Dec 31, 2015**
Shares outstanding	**118,263**	117,386	111,991
Potential shares issuable pursuant to the VIP	**3,090**	2,797	3,033
Diluted shares outstanding	**121,353**	120,183	115,024

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 3, 4, 5, 6]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

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

Loren M. Leiker [6]
Houston, Texas

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

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

Anthony Marino
Calgary, Alberta

Robert Michaleski [3]
Calgary, Alberta

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

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

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

ABBREVIATIONS

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in southeast Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
btu	British thermal units
CGU	Cash generating unit, the basis upon which Vermilion's assets are evaluated for potential impairments
DRIP	Dividend Reinvestment Plan
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

OFFICERS AND KEY PERSONNEL

CANADA
Anthony Marino
President & Chief Executive Officer

Curtis W. Hicks
Executive Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Daniel Goulet
Director Corporate HSE

Bryce Kremnica
Director Field Operations – Canada Business Unit

Kyle Preston
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan
Director Business Development

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES
Daniel G. Anderson
Managing Director – U.S. Business Unit

Timothy R. Morris
Director U.S. Business Development – U.S. Business Unit

EUROPE
Gerard Schut
Vice President European Operations

Darcy Kerwin
Managing Director - France Business Unit

Scott Seatter
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

HSBC Bank Canada

Wells Fargo Bank N.A., Canadian Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

Barclays Bank PLC

Canadian Western Bank

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

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

INVESTOR RELATIONS
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Director Investor Relations
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mmboe	million barrel of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid. Our production in Ireland is priced with reference to NBP.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
TTF	the day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
WTI	West Texas Intermediate, the reference price paid for

Managing Director - Australia Business Unit

ABBREVIATIONS

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in southeast Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
btu	British thermal units
DRIP	Dividend Reinvestment Plan
GJ	gigajoules
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboe	million barrel of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point. Our production in Ireland is priced with reference to NBP.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
TTF	the price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

DISCLAIMER

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

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

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

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

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* and the *Canadian Oil and Gas Evaluation Handbook* . 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.

MANAGEMENT'S REPORT TO SHAREHOLDERS

Management's Responsibility for Financial Statements

The accompanying consolidated financial statements of Vermilion Energy Inc. are the responsibility of management and have been approved by the Board of Directors of Vermilion Energy Inc. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes to the consolidated financial statements and are prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. Where necessary, management has made informed judgments and estimates of transactions that were not yet completed at the balance sheet date. Financial information throughout the Annual Report is consistent with the consolidated financial statements.

Management ensures the integrity of the consolidated financial statements by maintaining high-quality systems of internal control. Procedures and policies are designed to provide reasonable assurance that assets are safeguarded and transactions are properly recorded, and that the financial records are reliable for preparation of the consolidated financial statements. Deloitte LLP, Vermilion's Independent Registered Public Accounting Firm, have conducted an audit of the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) and have provided their report.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Board carries out this responsibility principally through the Audit Committee, which is appointed by the Board and is comprised entirely of independent Directors. The Committee meets periodically with management and Deloitte LLP to satisfy itself that each party is properly discharging its responsibilities and to review the consolidated financial statements, the Management's Discussion and Analysis and the Report of the Independent Registered Public Accounting Firm before they are presented to the Board of Directors.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining an adequate system of internal control over financial reporting. Management conducted an evaluation of the effectiveness of the system of internal control over financial reporting based on the criteria established in "Internal Control – Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has assessed the effectiveness of Vermilion's internal control over financial reporting as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Management concluded that Vermilion's internal control over financial reporting was effective as of December 31, 2016. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2016 has been audited by Deloitte LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2016.

("Anthony Marino")

Anthony Marino
President & Chief Executive Officer
February 24, 2017

("Curtis W. Hicks")

Curtis W. Hicks
Executive Vice President & Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Vermilion Energy Inc.

We have audited the internal control over financial reporting of Vermilion Energy Inc. and subsidiaries (the "Company") as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and our report dated February 24, 2017 expressed an unmodified/unqualified opinion on those financial statements.

("/s/ Deloitte LLP")

Chartered Professional Accountants
February 24, 2017
Calgary, Canada

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Vermilion Energy Inc.

We have audited the accompanying consolidated financial statements of Vermilion Energy Inc. and subsidiaries (the "Company"), which comprise the consolidated balance sheet as at December 31, 2016 and December 31, 2015, and the consolidated statements of net loss and comprehensive loss, cash flows, and changes in shareholders' equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Vermilion Energy Inc. and subsidiaries as at December 31, 2016 and December 31, 2015, and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

("/s/ Deloitte LLP")

Chartered Professional Accountants
February 24, 2017
Calgary, Canada

CONSOLIDATED BALANCE SHEET
(THOUSANDS OF CANADIAN DOLLARS)

	Note	December 31, 2016	December 31, 2015
ASSETS			
Current			
Cash and cash equivalents	20	**62,775**	41,676
Accounts receivable		**131,719**	160,499
Crude oil inventory		**14,528**	13,079
Derivative instruments	9	**4,336**	55,214
Prepaid expenses		**12,548**	14,310
		225,906	284,778
Derivative instruments	9	**1,157**	13,128
Deferred taxes	11	**152,046**	135,753
Exploration and evaluation assets	7	**274,830**	308,192
Capital assets	6	**3,433,245**	3,467,369
		4,087,184	4,209,220
LIABILITIES			
Current			
Accounts payable and accrued liabilities		**181,557**	248,747
Current portion of long-term debt	12	**-**	224,901
Dividends payable	13	**25,426**	24,077
Derivative instruments	9	**47,660**	-
Income taxes payable		**36,219**	6,006
		290,862	503,731
Derivative instruments	9	**27,484**	-
Long-term debt	12	**1,362,192**	1,162,998
Finance lease obligation	10	**19,628**	23,565
Asset retirement obligations	8	**525,022**	305,613
Deferred taxes	11	**283,533**	354,654
		2,508,721	2,350,561
SHAREHOLDERS' EQUITY			
Shareholders' capital	13	**2,452,722**	2,181,089
Contributed surplus		**101,788**	107,946
Accumulated other comprehensive income		**30,339**	113,647
Deficit		**(1,006,386)**	(544,023)
		1,578,463	1,858,659
		4,087,184	4,209,220

APPROVED BY THE BOARD

(Signed "Catherine L. Williams") *(Signed "Anthony Marino")*

Catherine L. Williams, Director Anthony Marino, Director

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

	Note	Year Ended December 31, 2016	Year Ended December 31, 2015
REVENUE			
Petroleum and natural gas sales		**882,791**	939,586
Royalties		**(54,284)**	(65,920)
Petroleum and natural gas revenue		**828,507**	873,666
EXPENSES			
Operating	20	**222,185**	225,938
Transportation		**39,511**	41,660
Equity based compensation	15	**69,235**	75,232
Loss (gain) on derivative instruments	9	**72,617**	(84,904)
Interest expense		**56,957**	59,852
General and administration	20	**52,829**	53,584
Foreign exchange gain		**(3,249)**	(9,410)
Other income	16	**(3,896)**	(31,663)
Accretion	8	**24,783**	23,911
Depletion and depreciation	6, 7	**528,002**	458,758
Impairment	6, 7	**14,762**	274,623
Gain on business combination	5	**(22,001)**	-
		1,051,735	1,087,581
LOSS BEFORE INCOME TAXES		**(223,228)**	(213,915)
TAXES	11		
Deferred		**(82,855)**	(47,728)
Current		**19,678**	51,115
		(63,177)	3,387
NET LOSS		**(160,051)**	(217,302)
OTHER COMPREHENSIVE (LOSS) INCOME			
Currency translation adjustments		**(83,308)**	107,925
COMPREHENSIVE LOSS		**(243,359)**	(109,377)
NET LOSS PER SHARE	17		
Basic		**(1.38)**	(1.98)
Diluted		**(1.38)**	(1.98)
WEIGHTED AVERAGE SHARES OUTSTANDING ('000s)	17		
Basic		**115,695**	109,642
Diluted		**115,695**	109,642

CONSOLIDATED STATEMENTS OF CASH FLOWS
(THOUSANDS OF CANADIAN DOLLARS)

	Note	Year Ended December 31, 2016	Year Ended December 31, 2015
OPERATING			
Net loss		**(160,051)**	(217,302)
Adjustments:			
Accretion	8	**24,783**	23,911
Depletion and depreciation	6, 7	**528,002**	458,758
Impairment	6, 7	**14,762**	274,623
Gain on business combination	5	**(22,001)**	-
Unrealized loss (gain) on derivative instruments	9	**137,993**	(43,548)
Equity based compensation	15	**69,235**	75,232
Unrealized foreign exchange loss (gain)		**792**	(8,787)
Unrealized other expense		**131**	1,008
Deferred taxes	11	**(82,855)**	(47,728)
Asset retirement obligations settled	8	**(9,617)**	(11,369)
Changes in non-cash operating working capital	20	**8,366**	(60,390)
Cash flows from operating activities		**509,540**	444,408
INVESTING			
Drilling and development	6	**(241,545)**	(486,861)
Exploration and evaluation	7	**(863)**	-
Property acquisitions	5, 6, 7	**(98,524)**	(28,897)
Changes in non-cash investing working capital	20	**(12,298)**	(25,980)
Cash flows used in investing activities		**(353,230)**	(541,738)
FINANCING			
Increase in long-term debt	12	**202,617**	138,341
Repayment of senior unsecured notes	12	**(225,000)**	-
Decrease in finance lease obligation	10	**(4,270)**	(2,246)
Cash dividends	13	**(104,723)**	(127,535)
Cash flows (used in) from financing activities		**(131,376)**	8,560
Foreign exchange (loss) gain on cash held in foreign currencies		**(3,835)**	10,041
Net change in cash and cash equivalents		**21,099**	(78,729)
Cash and cash equivalents, beginning of year		**41,676**	120,405
Cash and cash equivalents, end of year	20	**62,775**	41,676
Supplementary information for cash flows from operating activities			
Interest paid		**60,221**	62,911
Income taxes (received) paid		**(10,535)**	92,907

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

	Note	Year Ended December 31, 2016	Year Ended December 31, 2015
SHAREHOLDERS' CAPITAL			
Balance, beginning of period		**2,181,089**	1,959,021
Shares issued for the DRIP[(1)]	13	**192,998**	155,033
Vesting of equity based awards	13, 15	**67,146**	56,855
Equity based compensation	13, 15	**8,247**	2,619
Share-settled dividends on vested equity based awards	13, 15	**3,242**	7,561
Balance, end of period	13	**2,452,722**	2,181,089
CONTRIBUTED SURPLUS			
Balance, beginning of period		**107,946**	92,188
Equity based compensation	15	**60,988**	72,613
Vesting of equity based awards	13, 15	**(67,146)**	(56,855)
Balance, end of period		**101,788**	107,946
ACCUMULATED OTHER COMPREHENSIVE INCOME			
Balance, beginning of period		**113,647**	5,722
Currency translation adjustments		**(83,308)**	107,925
Balance, end of period		**30,339**	113,647
DEFICIT			
Balance, beginning of period		**(544,023)**	(35,585)
Net loss		**(160,051)**	(217,302)
Dividends declared	13	**(299,070)**	(283,575)
Share-settled dividends on vested equity based awards	13, 15	**(3,242)**	(7,561)
Balance, end of period		**(1,006,386)**	(544,023)
TOTAL SHAREHOLDERS' EQUITY		**1,578,463**	1,858,659

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

DESCRIPTION OF EQUITY RESERVES

Shareholders' capital
Represents the recognized amount for common shares when issued, net of equity issuance costs and deferred taxes.

Contributed surplus
Represents the recognized value of equity based awards that are settled in shares. Once vested, the value of the awards are transferred to shareholders' capital.

Accumulated other comprehensive income
Represents currency translation adjustments resulting from translating financial statements of subsidiaries with a foreign functional currency to Canadian dollars at period-end rates. These amounts may be reclassified to net earnings if there is a disposal or partial disposal of a subsidiary.

Deficit
Represents the cumulative net earnings and losses less distributed earnings of Vermilion Energy Inc.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2016 AND 2015
(TABULAR AMOUNTS IN THOUSANDS OF CANADIAN DOLLARS, EXCEPT SHARE AND PER SHARE AMOUNTS)

1. BASIS OF PRESENTATION

Vermilion Energy Inc. and its subsidiaries (the "Company" or "Vermilion") are engaged in the business of petroleum and natural gas exploration, development, acquisition, and production.

Vermilion was incorporated in Canada and the Company's registered office and principal place of business is located at 3500, 520, 3 rd Avenue SW, Calgary, Alberta, Canada.

These consolidated financial statements were approved and authorized for issuance by Vermilion's Board of Directors on February 24, 2017.

2. SIGNIFICANT ACCOUNTING POLICIES

Accounting Framework
The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Principles of Consolidation
The consolidated financial statements include the accounts of Vermilion Energy Inc. and its subsidiaries. Transactions between Vermilion Energy Inc. and its subsidiaries have been eliminated.

Vermilion accounts for joint operations by recognizing the Company's share of assets, liabilities, income and expenses.

Exploration and Evaluation Assets
Vermilion classifies costs as Exploration and Evaluation ("E&E") assets when they relate to exploring and evaluating an area for which the Company has the licence or right to explore and extract resources. E&E costs may include geological and geophysical costs, land acquisition costs, and costs for drilling, completion, and testing of exploration wells.

E&E costs are reclassified to capital assets if the technical feasibility and commercial viability of the area can be determined. E&E assets are assessed for impairment prior to any reclassification. The technical feasibility and commercial viability of extracting the reserves is considered to be determinable when proved and probable reserves are identified.

Costs incurred prior to the acquisition of the legal rights to explore an area are expensed as incurred. If reserves are not found within the license area or the area is abandoned, the related E&E costs are amortized over a period not greater than five years. If an exploration license expires prior to the commencement of exploration activities, the cost of the exploration license is written off through depletion in the year of expiration.

Capital Assets
Vermilion recognizes capital assets at cost less accumulated depletion, depreciation and impairment losses. Costs include directly attributable costs incurred for the drilling and completion of wells and the construction of production and processing facilities.

When components of capital assets are replaced, disposed of, or no longer in use, they are derecognized. Gains and losses on disposal of capital assets are determined by comparing the proceeds of disposal compared to the carrying amount.

Depletion and Depreciation
Capital assets are grouped into depletion units, which are groups of assets within a specific production area that have similar economic lives. Depletion units represent the lowest level of disaggregation for which costs are accumulated for the purposes of calculating depletion and depreciation.

The net carrying value of each depletion unit is depleted using the unit of production method by reference to the ratio of production in the period to the total proved and probable reserves, taking into account the future development costs necessary to bring the applicable reserves into production.

For the purposes of the depletion calculations, oil and gas reserves are converted to a common unit of measure on the basis of their relative energy content based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent.

Impairment of Capital Assets and Exploration and Evaluation Assets
Depletion units are aggregated into cash generating units ("CGUs") for impairment testing. CGUs are the lowest level for which there are identifiable cash inflows that are largely independent of cash inflows of other groups of assets. CGUs are reviewed for indicators of potential impairment at each reporting date.

E&E assets are tested for impairment when reclassified to capital assets or when indicators of potential impairment are identified. E&E assets are reviewed for indicators of potential impairment at each reporting date. If indicators of potential impairment are identified, E&E assets are tested for impairment as part of the CGU attributable to the jurisdiction the exploration area resides.

If an indicator of potential impairment exists, the CGU's carrying value is compared to its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. If the carrying amount of a CGU exceeds its recoverable amount, an impairment loss is recognized to reduce the carrying value of the CGU to its recoverable amount.

If an impairment loss has been recognized in a prior period, an assessment is performed at each reporting date to determine if the circumstances which led to the impairment loss have reversed. If the change in circumstances leads to the recoverable amount being higher than the carrying value after the impairment loss, then the impairment loss (net of depletion that would otherwise have been recorded) is reversed.

Finance leases
Finance leases are leases which transfer substantially all of the risks and rewards incidental to legal ownership of the leased asset to Vermilion. A finance lease obligation is recognized at the commencement of the lease term at the lower of fair value of the leased asset or the present value of the minimum lease payments.

Cash and Cash Equivalents
Cash and cash equivalents include cash on deposit with financial institutions and guaranteed investment certificates.

Crude Oil Inventory
Crude oil inventory is valued at the lower of cost or net realizable value. Cost of crude oil inventory produced is determined on a weighted-average basis and includes related operating expenses, royalties, and depletion.

Asset Retirement Obligations
Vermilion recognizes a provision for asset retirement obligations when an event occurs giving rise to an obligation of uncertain timing or amount. Asset retirement obligations are recognized on the consolidated balance sheet as a long-term liability with a corresponding increase to E&E or capital assets.

Asset retirement obligations reflect the present value of estimated future settlement costs. The discount rate used to calculate the present value is specific to the jurisdiction the obligation relates to and is reflective of current market assessment of the time value of money and risks specific to the liabilities that have not been reflected in the cash flow estimates.

Asset retirement obligations are remeasured at each reporting period to reflect changes in discount rates and estimated future settlement costs. Asset retirement obligations are increased each reporting period to reflect the passage of time with a corresponding charge to accretion expense.

Revenue Recognition
Revenues associated with the sale of petroleum and natural gas are recorded when title passes to the customer. Revenue is recognized when all the following conditions have been satisfied:

- Vermilion has transferred the significant risks and rewards of ownership of the petroleum and natural gas to the customer;
- Vermilion retains no continuing managerial involvement to the degree usually associated with ownership or effective control over the petroleum or natural gas sold;
- The amount of the revenue can be reliably measured;
- It is probable that the economic benefits associated with the transaction will flow to Vermilion; and
- The costs incurred or to be incurred in respect of the transaction can be measured reliably.

Financial Instruments
Financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods depends on the classification of the financial instrument as described below:

- Held for trading: Held for trading financial instruments are subsequently measured at fair value on the consolidated balance sheet and gains and losses are recognized in net earnings. Cash and cash equivalents and derivatives assets and liabilities are classified as held for trading.
- Loans and receivables and other financial liabilities: Loans and receivables and other financial liabilities are subsequently measured at amortized cost. Accounts receivable are classified as loans and receivables. Accounts payable and accrued liabilities, dividends payable, finance lease, and long-term debt are classified as other financial liabilities.

Equity Based Compensation
Equity based compensation expense results from equity-settled awards issued under Vermilion's long-term share-based compensation plan (the "Vermilion Incentive Plan" or "VIP") as well as the grant date fair value of Vermilion common shares issued under the Company's bonus and employee share savings plans.

Equity-settled awards issued under the VIP vest over a period of one to three years and awards outstanding are adjusted upon vesting by a performance factor determined by the Company's Board of Directors. Equity based compensation expense for the VIP is recognized over the vesting period with a corresponding adjustment to contributed surplus. The expense recognized is based on the grant date fair value of the VIP awards, an estimate of the performance factor that will be achieved, and an estimate of forfeiture rates based on historical vesting data. Dividends notionally accrue to the VIP awards and are excluded in the determination of grant date fair values. Upon vesting, the amount recognized in contributed surplus is reclassified to shareholders' capital.

The grant date fair value of the equity-settled awards issued under the VIP and the grant date fair value of Vermilion common shares issued under the Company's bonus and employee share savings plans are determined as the closing price of Vermilion's common shares on the Toronto Stock Exchange on the grant date.

Per Share Amounts
Basic net loss per share is calculated by dividing net loss by the weighted-average number of shares outstanding during the period.

Diluted net loss per share is calculated by dividing net loss by the diluted weighted-average number of shares outstanding during the period. The diluted weighted-average number of shares outstanding is the sum of the weighted-average number of shares outstanding and, to the extent inclusion reduces net earnings per share, the number of shares issuable under the VIP determined using the treasury stock method. The treasury stock method assumes that the unrecognized equity based compensation expense are deemed proceeds used to repurchase Vermilion common shares at the average market price during the period.

Foreign Currency Translation
Vermilion Energy Inc.'s functional and presentation currency is the Canadian dollar. Vermilion has subsidiaries that transact and operate in countries other than Canada and have functional currencies other than the Canadian dollar.

Foreign currency translations include the translation of foreign currency transactions and the translation of foreign operations.

Foreign currency translations occur when translating transactions in foreign currencies to the applicable functional currency of Vermilion Energy Inc. and its subsidiaries. Gains and losses from foreign currency transactions are recorded as foreign exchange gains or losses. Translations occur as follows:

- Income and expenses are translated at the prevailing rates on the date of the transaction
- Non-monetary assets or liabilities are carried at the prevailing rates on the date of the transaction
- Monetary items are translated at the prevailing rates at the balance sheet date

Foreign operation translations occur when translating the financial statements of non-Canadian functional currency subsidiaries to the Canadian dollar and when translating intercompany loans that are deemed to represent net investments in a foreign subsidiary. Gains and losses from foreign operation translations are recorded as currency translation adjustments. Translations occur as follows:

- Income and expenses are translated at the average exchange rates for the period
- Assets and liabilities are translated at the prevailing rates on the balance sheet date.

Income Taxes
Deferred taxes are calculated using the balance sheet method. Deferred tax is recognized for the estimated effect of any temporary differences between the amounts recognized on Vermilion's consolidated balance sheet and the respective tax basis. This calculation uses enacted or substantively enacted tax rates that are expected to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred taxes is recognized in the period the related legislation is substantively enacted.

Deferred tax assets are recognized to the extent that it is probable that future taxable profits will be available against which the deductible temporary differences can be used. Deferred tax assets are reviewed at each reporting date and are reduced to the extent it is no longer probable that the related tax benefit will be realized.

Management Judgments and Estimation Uncertainty
The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income and expenses. Actual results could differ significantly from these estimates.

Key areas where management has made judgments, estimates, and assumptions include:

- Asset retirement obligations: Asset retirement obligations are based on judgments regarding regulatory requirements, estimates of future costs, and the expected timing of expenditures. The carrying balance of asset retirement obligations and accretion expense may differ due to changes in: laws and regulations, technology, the expected timing of expenditures, and market conditions affecting the discount rate applied.
- Determination of CGUs: CGU determination is subject to management's judgment of the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The factors used by Vermilion to determine CGUs vary by jurisdiction due to their unique operating and geographic conditions. In general, Vermilion will assess the following factors: geographic proximity of the assets within a group to one another, geographic proximity of the group of assets to other groups of assets, homogeneity of the production from the group of assets and the sharing of infrastructure used to process and/or transport production. The composition of CGUs can directly impact the calculated recoverable amount of a CGU and the recorded impairment loss or recovery.
- Assessment of impairments or recovery of previous impairments: The calculation of the recoverable amount of a CGU is based on market factors (including estimated future commodity prices) and estimates of reserves and resources. Reserve and resource estimates are based on: engineering data, estimated future commodity prices, expected future rates of production, and assumptions regarding the timing and amount of future expenditures. Changes in these judgments, estimates and assumptions can directly impact the calculated recoverable amount of a CGU and the recorded impairment loss or recovery.
- Income Taxes: Tax interpretations, regulations, and legislation in the various jurisdictions in which Vermilion and its subsidiaries operate are subject to change and interpretation. Changes in laws and interpretations can affect the timing of the reversal of temporary tax differences, the tax rates in effect when such differences reverse and Vermilion's ability to use tax losses and other tax pools in the future. The Company's income tax filings are subject to audit by taxation authorities in numerous jurisdictions and the results of such audits may increase or decrease the tax liability. The determination of tax amounts recognized in the consolidated financial statements are based on management's assessment of the tax positions, which includes consideration of their technical merits, communications with tax authorities and management's view of the most likely outcome.

3. CHANGES TO ACCOUNTING PRONOUNCEMENTS

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

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

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

In the adoption of IFRS 15, Vermilion has in place a transition team that will perform a detailed review of the Company's standard contracts with customers in accordance with the issued IFRS.

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

4. SEGMENTED INFORMATION

Vermilion has a decentralized business unit structure designed to manage assets in each country the Company operates in. Excluding the Corporate segment, each of the below operating segments derives its revenues solely from the production and sale of petroleum and natural gas.

Vermilion's Corporate segment aggregates costs incurred at the Company's Corporate head office located in Calgary, Alberta, Canada as well as costs incurred relating to Vermilion's exploration activities in Central and Eastern Europe. These operating segments have similar economic characteristics as they do not currently generate revenue.

Vermilion's Chief Operating Decision maker regularly reviews fund flows from operations generated by each of Vermilion's operating segments. Fund flows from operations is a measure of profit or loss that provides the Chief Operating Decision maker with the ability to assess the operating segments' profitability and, correspondingly, the ability of each operating segment to fund its share of dividends, asset retirement obligations, and capital investments.

Vermilion has three major customers with revenues in excess of 10% of consolidated revenues within the France, Netherlands, and Ireland operating segments. Substantially all sales in the France, Netherlands, and Ireland operating segments for the years ended December 31, 2016 and 2015 were to one customer in each respective segment.

	Year Ended December 31, 2016								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,522,243	835,141	220,350	292,885	756,893	267,183	61,195	131,294	4,087,184
Drilling and development	62,706	68,472	23,740	3,803	9,375	59,910	13,539	-	241,545
Exploration and evaluation	-	-	-	-	-	-	-	863	863
Oil and gas sales to external customers	252,867	246,863	100,707	29,049	109,156	136,835	7,314	-	882,791
Royalties	(21,475)	(27,091)	(1,462)	(2,089)	-	-	(2,167)	-	(54,284)
Revenue from external customers	231,392	219,772	99,245	26,960	109,156	136,835	5,147	-	828,507
Transportation	(15,392)	(14,758)	-	(2,869)	(6,492)	-	-	-	(39,511)
Operating	(71,543)	(50,000)	(20,796)	(12,379)	(18,646)	(47,507)	(1,314)	-	(222,185)
General and administration	(11,826)	(19,101)	(1,525)	(8,314)	(4,772)	(6,400)	(3,624)	2,733	(52,829)
PRRT	-	-	-	-	-	(1,568)	-	-	(1,568)
Corporate income taxes	-	(2,867)	(6,624)	-	-	(7,522)	-	(1,097)	(18,110)
Interest expense	-	-	-	-	-	-	-	(56,957)	(56,957)
Realized gain on derivative instruments	-	-	-	-	-	-	-	65,376	65,376
Realized foreign exchange gain	-	-	-	-	-	-	-	4,041	4,041
Realized other income	-	3,822	-	-	-	-	-	205	4,027
Fund flows from operations	132,631	136,868	70,300	3,398	79,246	73,838	209	14,301	510,791

	Year Ended December 31, 2015								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,609,180	863,304	212,749	167,908	908,453	235,139	42,927	169,560	4,209,220
Drilling and development	201,508	92,265	47,325	5,363	66,409	61,741	12,250	-	486,861
Oil and gas sales to external customers	320,613	281,422	129,057	41,384	57	162,765	4,288	-	939,586
Royalties	(28,144)	(26,958)	(3,082)	(6,479)	-	-	(1,257)	-	(65,920)
Revenue from external customers	292,469	254,464	125,975	34,905	57	162,765	3,031	-	873,666
Transportation	(16,326)	(15,378)	-	(3,269)	(6,687)	-	-	-	(41,660)
Operating	(89,085)	(50,718)	(22,746)	(10,956)	(15)	(51,676)	(742)	-	(225,938)
General and administration	(16,888)	(20,217)	(4,158)	(7,386)	(2,517)	(5,754)	(3,836)	7,172	(53,584)
PRRT	-	-	-	-	-	(6,878)	-	-	(6,878)
Corporate income taxes	-	(23,764)	(12,152)	-	-	(7,230)	-	(1,091)	(44,237)
Interest expense	-	-	-	-	-	-	-	(59,852)	(59,852)
Realized gain on derivative instruments	-	-	-	-	-	-	-	41,356	41,356
Realized foreign exchange gain	-	-	-	-	-	-	-	623	623
Realized other income	-	31,775	-	-	-	-	-	896	32,671
Fund flows from operations	170,170	176,162	86,919	13,294	(9,162)	91,227	(1,547)	(10,896)	516,167

Reconciliation of fund flows from operations to net loss

	Year Ended	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Fund flows from operations	**510,791**	516,167
Accretion	**(24,783)**	(23,911)
Depletion and depreciation	**(528,002)**	(458,758)
Impairment	**(14,762)**	(274,623)
Gain on business combination	**22,001**	-
Unrealized (loss) gain on derivative instruments	**(137,993)**	43,548
Equity based compensation	**(69,235)**	(75,232)
Unrealized foreign exchange (loss) gain	**(792)**	8,787
Unrealized other expense	**(131)**	(1,008)
Deferred taxes	**82,855**	47,728
Net loss	**(160,051)**	(217,302)

5. BUSINESS COMBINATIONS

In December of 2016, Vermilion acquired, through a wholly-owned subsidiary, interests in production and exploration assets in Germany from Engie E&P Deutschland GmbH. The acquisition includes operated and non-operated interests in five oil and three gas producing fields, along with an operated interest in one exploration license. The acquisition provides Vermilion its first operated producing properties in Germany, and advances the Company's objective of developing a material business unit in this country.

The acquisition was accounted for as a business combination. The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are summarized as follows:

($M)	**Consideration**
Cash paid to vendor	48,377
Total consideration	48,377

($M)	**Allocation of Consideration**
Capital assets	142,350
Asset retirement obligations	(66,965)
Deferred taxes	(7,767)
Crude oil inventory	2,760
Net assets acquired	70,378
Gain on business combination	(22,001)
Total net assets acquired, net of gain on business combination	48,377

In calculating the fair value of capital assets, Vermilion considered the net present value of after-tax cash flows from proved plus probable reserves using applicable price decks published by reserve engineering firms (refer to Financial Statement Note 6) and an after-tax discount rate of 12%.

The determination of asset retirement obligations was based on a total undiscounted future liability of $182.3 million. These payments are expected to be made between 2027 and 2049, with the majority of spending occurring between 2043 and 2049 ($78.8 million). The inflation rate used in determining the cash flow estimates was 1.28%. The present value of the obligations was calculated using a credit-adjusted risk-free rate, calculated using a credit spread of 3.8% added to a risk-free rate of 0.9%. Refer to Financial Statement Note 8 for additional information regarding asset retirement obligations.

As the acquisition of control occurred late in 2016, the results of operations from the assets acquired were not significant to Vermilion's consolidated financial statements for the year ended December 31, 2016. Had the acquisition occurred on January 1, 2016, management estimates that consolidated revenues would have increased by $29.3 million and consolidated fund flows from operations would have increased by $8.1 million for the year ended December 31, 2016. Fund flows from operations is Vermilion's measure of profit or loss in accordance with IFRS 8 "Operating Segments". Please see Financial Statement Note 4 for a reconciliation of fund flows from operations to net earnings.

The gain on business combination resulted from the recognition of additional reserve value when the acquisition closed in December 2016, compared to the estimated value in June when Vermilion entered into a definitive purchase and sale agreement and the acquisition price was determined.

6. CAPITAL ASSETS

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

($M)	2016	2015
Balance at January 1	**3,467,369**	3,511,092
Additions	**241,545**	486,861
Property acquisitions	**189,853**	27,731
Changes in asset retirement obligations	**149,492**	(78,429)
Depletion and depreciation	**(491,508)**	(438,342)
Recognition of finance lease asset	**960**	31,028
Impairment	**(14,762)**	(219,808)
Foreign exchange	**(109,704)**	147,236
Balance at December 31	**3,433,245**	3,467,369
Cost	**6,256,485**	5,682,461
Accumulated depletion and depreciation	**(2,823,240)**	(2,215,092)
Carrying amount at December 31	**3,433,245**	3,467,369

Impairment
As at December 31, 2016, Vermilion did not identify any indicators of impairment. However, Vermilion recorded an impairment in the three months ended March 31, 2016.

In assessing the recoverable value of a CGU, Vermilion considers the higher of its fair value less costs of disposal and its value in use. For the periods ended March 31, 2016 and December 31, 2015, Vermilion considered the net present value of after-tax cash flows from proved plus probable reserves based on the applicable price decks published by GLJ Petroleum Consultants, Sproule, and McDaniel and Associates. In both 2016 and 2015, Vermilion applied an after-tax discount rate of 9%.

In addition, where applicable, Vermilion also considered:
- The fair value of undeveloped land determined based on orderly land transactions with similar characteristics as Vermilion's undeveloped land.
- The net present value of contingent and prospective resources, discounted at an after-tax discount rate of 15%.

Amounts calculated using fair value less costs of disposal are categorized as a Level 3 fair value measurements due to the use of unobservable inputs in the calculation.

In 2015, as a result of declines in price forecasts for crude oil and Canadian natural gas, Vermilion recorded a non-cash impairment charge of $274.6 million ($219.8 million relating to capital assets and $54.8 million relating to E&E assets) in the Canada segment. The impairment charge related to the light crude oil play in Saskatchewan ($267.9 million based on a recoverable amount of $266.8 million) and shallow coal bed methane properties in Alberta ($6.7 million based on a recoverable amount of $19.7 million).

In the first quarter of 2016, as a result of declines in price forecasts for European natural gas, Vermilion recorded a non-cash impairment charge of $14.8 million (based on a recoverable amount of $737.3 million) in the Ireland segment.

The following table outlines the forward commodity price estimates that were used to assess impairment as at December 31, 2016, as well as to determine the fair value of capital assets for the business combination discussed in Financial Statement Note 5.

Forward Commodity Price Assumptions										
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026 [1]
NBP (€/mmbtu)[2]	5.63	5.86	5.98	6.43	6.61	6.75	6.88	7.02	7.16	7.30
WTI (US $/bbl)[3]	55.00	60.90	65.47	69.13	73.21	75.19	77.19	79.23	81.28	83.39
Brent (US $/bbl)[3]	56.00	61.90	66.47	70.50	74.58	76.56	78.56	80.60	82.68	84.98
AECO ($/mmbtu)[3]	3.43	3.17	3.26	3.67	3.86	3.97	4.11	4.23	4.31	4.41

[1] Escalated at 2.0% per year thereafter.

[2] Source: Average of GLJ Petroleum Consultants and Sproule price forecasts, effective January 1, 2017.

[3] Source: Average of GLJ Petroleum Consultants, Sproule, and McDaniel & Associates Consultants price forecasts, effective January 1, 2017.

The determination of impairment is sensitive to changes in key judgements, including reserve revisions, changes in forward commodity prices and exchange rates, and changes in costs and timing of development. Changes in these key judgments would impact the recoverable amounts of CGUs, therefore resulting in additional impairment charges and reversals. The following table demonstrates the impact of a 5% decrease in commodity price estimates and a 1% increase in discount rate assumptions on the recorded impairment as at December 31, 2016:

($M)	1% Increase in Discount Rate	5% Decrease in Commodity Prices
Saskatchewan light crude oil	-	(8,304)
Alberta shallow coal bed methane	-	(853)
Ireland natural gas	-	-
Impairment	-	(9,157)

7. EXPLORATION AND EVALUATION ASSETS

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

($M)	2016	2015
Balance January 1	**308,192**	380,621
Additions	**863**	-
Property acquisitions	**2,644**	1,166
Changes in asset retirement obligations	**14**	(130)
Depreciation	**(35,238)**	(21,893)
Impairment[(1)]	**-**	(54,815)
Foreign exchange	**(1,645)**	3,243
Balance December 31	**274,830**	308,192
Cost	**333,835**	362,919
Accumulated depreciation	**(59,005)**	(54,727)
Carrying amount at December 31	**274,830**	308,192

(1) Refer to Financial Statement Note 6 – Capital Assets

8. ASSET RETIREMENT OBLIGATIONS

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

($M)	2016	2015
Balance at January 1	**305,613**	350,753
Additional obligations recognized	**68,288**	3,550
Changes in estimates	**3,454**	1,117
Obligations settled	**(9,617)**	(11,369)
Accretion	**24,783**	23,911
Changes in discount rates	**144,729**	(83,226)
Foreign exchange	**(12,228)**	20,877
Balance at December 31	**525,022**	305,613

Vermilion has estimated the asset retirement obligations based on a total undiscounted future liability of $1.4 billion (2015 - $1.3 billion). These payments are expected to be made between 2017 and 2065, with the majority of spending occurring between 2030 and 2037 ($348.2 million) and between 2044 and 2048 ($241.5 million). Inflation rates used in determining the cash flow estimates were between 0.5% and 2.2% (2015 - between 0.6% and 2.4%). Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 3.8% (2015 - 7.0%) added to risk-free rates based on long-term, risk-free government bonds.

The risk-free rates used to discount the obligations were as follows:

	Dec 31, 2016	Dec 31, 2015
Canada	**2.3%**	2.2%
France	**1.7%**	2.1%
Netherlands	**(0.3%)**	0.1%
Germany	**0.9%**	0.7%
Ireland	**0.5%**	1.0%
Australia	**3.2%**	3.3%
USA	**2.6%**	2.5%

A 0.5% increase/decrease in the credit spread would decrease/increase asset retirement obligations by approximately $40.0 million.

9. DERIVATIVE INSTRUMENTS

The following table reconciles the change in the fair value of Vermilion's derivative instruments:

	Year Ended	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Fair value of contracts, beginning of year	**68,342**	24,794
Reversal of opening contracts settled during the year	**(55,214)**	(23,391)
Realized gain on contracts settled during the year	**65,376**	41,356
Unrealized gain during the year on contracts outstanding at the end of the year	**(82,779)**	66,939
Net receipt from counterparties on contract settlements during the year	**(65,376)**	(41,356)
Fair value of contracts, end of year	**(69,651)**	68,342
Comprised of:		
Current derivative asset	**4,336**	55,214
Current derivative liability	**(47,660)**	-
Non-current derivative asset	**1,157**	13,128
Non-current derivative liability	**(27,484)**	-
Fair value of contracts, end of year	**(69,651)**	68,342

The loss (gain) on derivative instruments for 2016 and 2015 were comprised of the following:

	Year Ended	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Realized gain on contracts settled during the year	**(65,376)**	(41,356)
Reversal of opening contracts settled during the year	**55,214**	23,391
Unrealized loss (gain) during the year on contracts outstanding at the end of the year	**82,779**	(66,939)
Loss (gain) on derivative instruments	**72,617**	(84,904)

10. LEASES

Vermilion had the following future commitments associated with its operating leases:

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Less than 1 year	**12,683**	12,535
1 - 3 years	**21,087**	22,049
4 - 5 years	**18,228**	16,617
After 5 years	**1,657**	9,288
Total minimum lease payments	**53,655**	60,489

A solution gas facility used in Vermilion's southeast Saskatchewan operations has been recorded as a finance lease. The assets are to be used for a minimum period of 10 years, with an option to renew for successive one year terms. As at December 31, 2016, the carrying amount of the asset included in capital assets is $26.1 million.

Vermilion had the following future commitments associated with its finance lease:

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Less than 1 year	**6,495**	6,285
1 - 3 years	**12,990**	12,571
4 - 5 years	**6,043**	9,515
After 5 years	**4,501**	6,984
Total minimum lease payments	**30,029**	35,355
Amounts representing interest	**(3,894)**	(5,940)
Present value of net minimum lease payments	**26,135**	29,415
Current portion of finance lease obligation	**(6,507)**	(5,850)
Non-current portion of finance lease obligation	**19,628**	23,565

11. TAXES

The following table reconciles Vermilion's deferred tax asset and liability:

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Deferred tax liabilities:		
Derivative contracts	**-**	(18,452)
Capital assets	**(265,772)**	(331,176)
Non-capital losses	**20,561**	102,209
Asset retirement obligations	**(20,577)**	(82,586)
Unrealized foreign exchange	**(15,386)**	(16,291)
Other	**(2,359)**	(8,358)
Deferred tax liabilities	**(283,533)**	(354,654)
Deferred tax assets:		
Derivative contracts	**18,806**	-
Capital assets	**(55,718)**	58,846
Non-capital losses	**155,447**	72,846
Asset retirement obligations	**28,960**	3,583
Unrealized foreign exchange	**(72)**	-
Other	**4,623**	478
Deferred tax assets	**152,046**	135,753

Income tax expense differs from the amount that would have been expected if the reported earnings had been subject only to the statutory Canadian income tax rate as follows:

	Year Ended	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Loss before income taxes	**(223,228)**	(213,915)
Canadian corporate tax rate [(1)]	**27.0%**	26.2%
Expected recovery	**(60,272)**	(56,046)
Increase (decrease) in taxes resulting from:		
Petroleum resource rent tax rate (PRRT) differential [(2)]	**1,064**	8,310
Foreign tax rate differentials [(2), (3)]	**(16,675)**	(8,096)
Equity based compensation expense	**14,987**	14,000
Amended returns and changes to estimated tax pools and tax positions	**6,451**	(6,856)
Statutory rate changes and the estimated reversal rates associated with temporary differences	**(53,150)**	1,733
De-recognition	**46,253**	51,736
Adjustment for uncertain tax positions	**3,675**	-
Other non-deductible items	**(5,510)**	(1,394)
Provision for income taxes	**(63,177)**	3,387

(1) The corporate tax rate increased to 27.0% in 2016 from 26.2% in 2015 as a result of the 2016 full year impact from the Alberta corporate tax rate increase of 2.0% effective July 1, 2015.
(2) In Australia, current taxes include both corporate income tax rates and PRRT. Corporate income tax rates were applied at a rate of 30% and PRRT was applied at a rate of 40%.
(3) The combined tax rate was 34.4% in France, 50.0% in the Netherlands, 24.2% in Germany, 25% in Ireland, and 35% in the United States.

At December 31, 2016, Vermilion has $1.0 billion (2015 - $0.8 billion) of unused tax losses of which $520 million expire between 2030 and 2035.

At December 31, 2016, Vermilion de-recognized $96.1 million (2015 - $51.7 million) of deferred tax assets, relating to certain non-expiring non-capital losses for which there is uncertainty as to the Company's ability to fully utilize such losses when applying forecasted commodity prices in effect as at December 31, 2016.

The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have not been recognized as at December 31, 2016 is approximately $1.5 billion (2015 – approximately $1.4 billion).

12. LONG-TERM DEBT

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

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Revolving credit facility	**1,362,192**	1,162,998
Senior unsecured notes [(1)]	**-**	224,901
Long-term debt	**1,362,192**	1,387,899

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

Revolving Credit Facility

At December 31, 2016, Vermilion had in place a bank revolving credit facility maturing May 31, 2019 with the following terms:

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Total facility amount	**2,000,000**	2,000,000
Amount drawn	**(1,362,192)**	(1,162,998)
Letters of credit outstanding [(1)]	**(20,100)**	(25,200)
Unutilized capacity	**617,708**	811,802

(1) Included in letters of credit outstanding is a $17.8 million surety bond issued pursuant to the recovery of costs discussed in Financial Statement Note 16.

The facility is extendable from time to time, but not more than once per year, for a period not longer than four years, at the option of the lenders and upon notice from Vermilion. If no extension is granted by the lenders, the amounts owing pursuant to the facility are due at the maturity date. The facility bears interest at a rate applicable to demand loans plus applicable margins. The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion.

As at December 31, 2016, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	**Limit**	**Dec 31, 2016**	**Dec 31, 2015**
Consolidated total debt to consolidated EBITDA	4.0	**2.36**	2.23
Consolidated total senior debt to total capitalization	55%	**46%**	36%

The financial covenants include financial measures defined within the revolving credit facility agreement that are not defined under IFRS. These financial measures are defined by the 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 the balance sheet classified as "Shareholders' equity" plus consolidated total debt as defined above.

13. SHAREHOLDERS' CAPITAL

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

	2016		2015	
Shareholders' Capital	**Shares ('000s)**	**Amount ($M)**	**Shares ('000s)**	**Amount ($M)**
Balance as at January 1	**111,991**	**2,181,089**	107,303	1,959,021
Shares issued for the DRIP	**4,672**	**192,998**	3,338	155,033
Vesting of equity based awards	**1,320**	**67,146**	1,158	56,855
Shares issued for equity based compensation	**193**	**8,247**	57	2,619
Share-settled dividends on vested equity based awards	**87**	**3,242**	135	7,561
Balance as at December 31	**118,263**	**2,452,722**	111,991	2,181,089

Vermilion is authorized to issue an unlimited number of common shares with no par value.

Dividends declared to shareholders for the year ended December 31, 2016 were $299.1 million or $2.58 per common share (2015 - $283.6 million or $2.58 per common share). Dividends are approved by the Board of Directors and are paid monthly.

Vermilion has a dividend reinvestment plan ("DRIP") with a Premium Dividend ^{TM} component. The DRIP allows eligible holders of common shares to purchase additional common shares at a discount to market by reinvesting their cash dividends. The Premium Dividend^{TM} component allows eligible holders of common shares to reinvest their dividends in new common shares that are exchanged for a premium cash payment equal to 101.5% of the reinvested dividends.

Subsequent to the end of year-end and prior to the consolidated financial statements being authorized for issue on February 24, 2017, Vermilion declared dividends totalling $51.0 million or $0.215 per share for each of January and February of 2017.

14. CAPITAL DISCLOSURES

Vermilion defines capital as net debt (long-term debt plus net working capital) and shareholders' capital.

In managing capital, Vermilion reviews whether fund flows from operations (refer to Financial Statement Note 4 - Segmented Information) is sufficient to fund capital expenditures, dividends, and asset retirement obligations. To the extent that forecasted fund flows from operations are not sufficient in relation to these expenditures, Vermilion will reduce some or all categories of these expenditures or evaluate its ability to fund the expenditures with the issuance of debt or equity.

To manage capital, Vermilion monitors the ratio of net debt to fund flows from operations. Vermilion has historically maintained a ratio of between 1.0 to 1.5. However, as a result of the decline in commodity prices in 2015 and 2016 and the corresponding reduction to fund flows from operations, this ratio has increased to 2.7 times and 2.8 times, respectively. Vermilion has responded to this increase by reducing capital expenditures and implementing the Premium Dividend^{TM} component of the Dividend Reinvestment Plan.

Vermilion's revolving credit facility has financial covenants described in Financial Statement Note 12 - Long-Term Debt. As at December 31, 2016 and 2015, Vermilion was in compliance with these financial covenants.

The following table calculates Vermilion's ratio of net debt to fund flows from operations:

	Year Ended	
($M except as indicated)	**Dec 31, 2016**	**Dec 31, 2015**
Long-term debt	**1,362,192**	1,162,998
Current liabilities	**290,862**	503,731
Current assets	**(225,906)**	(284,778)
Net debt	**1,427,148**	1,381,951
Fund flows from operations	**510,791**	516,167
Ratio of net debt to fund flows from operations	**2.8**	2.7

15. EQUITY BASED COMPENSATION

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

Number of Awards ('000s)	2016	2015
Opening balance	**1,711**	1,775
Granted	**777**	609
Vested	**(628)**	(587)
Modified	**11**	-
Forfeited	**(133)**	(86)
Closing balance	**1,738**	1,711

For the year ended December 31, 2016, the awards granted had a weighted average fair value of $38.41 (2015 - $53.80). Equity based compensation expense is calculated based on the VIP awards outstanding multiplied by the estimated performance factor that will be realized upon vesting (2016 - 1.9; 2015 - 1.9) adjusted by an estimated annual forfeiture rate (2016 - 4.6%; 2015 - 4.8%). Equity based compensation expense of $61.0 million was recorded during the year ended December 31, 2016 (2015 - $72.6 million) related to the VIP.

16. OTHER INCOME

In 2015, Vermilion was awarded a recovery of costs resulting from an oil spill at the Ambès oil terminal in France that occurred in 2007. The French court awarded Vermilion approximately €25 million (before taxes), of which 50% was due immediately to Vermilion upon posting a surety bond. The payment was received in 2015, with the remainder due upon conclusion of the appeal process. Approximately 90% of the recovery was recorded as other income in 2015.

In the fourth quarter of 2016, the Court of Appeal of Versailles maintained this award. The remaining payment was received and Vermilion's surety bond was returned in 2017. While further appeal may be possible to the Supreme Court in France, Vermilion is virtually certain that the award will be upheld. Following the decision by the Court of Appeal, Vermilion recognized the remaining amount of the recovery (approximately $3.8 million) as other income in 2016.

17. PER SHARE AMOUNTS

Basic and diluted net loss per share have been determined based on the following:

	Year Ended	
($M except per share amounts)	**Dec 31, 2016**	**Dec 31, 2015**
Net loss	**(160,051)**	(217,302)
Basic weighted average shares outstanding ('000s)	**115,695**	109,642
Dilutive impact of VIP ('000s)	**-**	-
Diluted weighted average shares outstanding ('000s)	**115,695**	109,642
Basic loss per share	**(1.38)**	(1.98)
Diluted loss per share	**(1.38)**	(1.98)

The impact of shares issuable under the VIP is anti-dilutive and has been excluded from the calculation of diluted loss per share. The number of shares issuable under the VIP calculated using the treasury stock method for the year ended December 31, 2016 is 1,457 thousand (2015 – 1,409 thousand).

18. FINANCIAL INSTRUMENTS

Classification of Financial Instruments

The following table summarizes information relating to Vermilion's financial instruments

	As at Dec 31, 2016		As at Dec 31, 2015	
	Carrying value	**Fair value**	**Carrying value**	**Fair value**
FINANCIAL ASSETS				
Held for trading				
Cash and cash equivalents	**62,775**	**62,775**	41,676	41,676
Derivative assets	**5,493**	**5,493**	68,342	68,342
Loans and receivables				
Accounts receivable	**131,719**	**131,719**	160,499	160,499
FINANCIAL LIABILITIES				
Held for trading				
Derivative liabilities	**(75,144)**	**(75,144)**	-	-
Other financial liabilities				
Accounts payable and accrued liabilities	**(181,557)**	**(181,557)**	(248,747)	(248,747)
Dividends Payable	**(25,426)**	**(25,426)**	(24,077)	(24,077)
Long-term debt	**(1,362,192)**	**(1,362,192)**	(1,387,899)	(1,387,998)

Fair value measurements are categorized into a fair value hierarchy based on the lowest level input that is significant to the fair value measurement.

- Level 1 inputs are determined by reference to unadjusted quoted prices in active markets for identical assets or liabilities. Inputs used in fair value measurement of cash and cash equivalents are categorized as Level 1.
- Level 2 inputs are determined based on inputs other than unadjusted quoted prices that are observable, either directly or indirectly. The fair value of Vermilion's derivative assets and liabilities are determined using pricing models that incorporate future price forecasts (supported by prices from observable market transactions) and credit risk adjustments. The fair value of Vermilion's senior unsecured notes (included in the fair value of long-term debt as at December 31, 2015) was determined using pricing models that incorporated market rates for similar instruments.
- Level 3 inputs are not based on observable market data. Vermilion does not have any financial instruments classified as Level 3.

There were no transfers between levels in the hierarchy in the years ended December 31, 2016 and 2015.

The carrying value of accounts receivable, accounts payable and accrued liabilities, and dividends payable are a reasonable approximation of their fair value due to the short maturity of these financial instruments. The carrying value of long-term debt outstanding on the revolving credit facility approximates its fair value due to the use of short-term borrowing instruments at market rates of interest.

Nature and Extent of Risks Associated with Financial Instruments

Vermilion is exposed to financial risks from its financial instruments. These financial risks include: market risk, credit risk, and liquidity risk.

Market Risk

Market risk includes: commodity price risk, interest rate risk, and currency risk.

Commodity price risk

Vermilion is exposed to commodity price risk on its derivative assets and liabilities which are used as part of the Company's risk management program to mitigate the effects of changes in commodity prices on future cash flows. While transactions of this nature relate to a forecasted future petroleum and natural gas production, Vermilion does not designate these derivative assets and liabilities as accounting hedges. As such, changes in commodity prices impact the fair value of derivative instruments and the corresponding gains or losses on derivative instruments.

Currency risk

Vermilion is exposed to currency risk on its financial instruments denominated in foreign currencies. These financial instruments include cash and cash equivalents, accounts receivables, and accounts payables. As crude oil is typically sold in US dollars and as result of the Company's operations in Europe, Vermilion is primarily exposed to the US Dollar and Euro. The impact related to working capital is somewhat mitigated as a result of the offsetting effects of foreign exchange fluctuations on assets and liabilities. Vermilion monitors its exposure to currency risk and reviews whether the use of derivative financial instruments is appropriate to manage potential fluctuations in foreign exchange rates.

Interest rate risk
Vermilion is exposed to interest rate risk on its long-term debt. As at December 31, 2016, long-term debt was comprised solely of borrowings under the revolving credit facility. As these borrowings consist of short-term borrowing instruments that bear interest at market rates, changes in interest rates could result in an increase or decrease in the amount paid by Vermilion to service this debt. In both 2015 and 2016, Vermilion had in place interest rate swaps that mitigate some of the effects of changes in variable interest rates.

The following table summarizes the increase (positive values) or decrease (negative values) to comprehensive income before tax impact due to a change in the value of Vermilion's financial instruments as a result of a change in the relevant market risk variable. This analysis does not attempt to reflect any interdependencies between the relevant risk variables.

($M)	Dec 31, 2016	Dec 31, 2015
Currency risk - Euro to Canadian		
5% increase in strength of the Canadian dollar against the Euro	**1,338**	(1,986)
5% decrease in strength of the Canadian dollar against the Euro	**(1,338)**	1,986
Currency risk - US $ to Canadian		
5% increase in strength of the Canadian dollar against the US $	**(59,280)**	3,423
5% decrease in strength of the Canadian dollar against the US $	**59,280**	(3,423)
Commodity price risk		
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(26,513)**	(3,262)
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**18,882**	3,263
€ 0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	**(36,999)**	(23,813)
€ 0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	**33,019**	21,754
Interest rate risk		
1% increase in average Canadian prime interest rate	**(11,674)**	(10,543)
1% decrease in average Canadian prime interest rate	**11,674**	10,543

The above table shows the before tax effect on comprehensive income for a 5% change in the US dollar to Canadian dollar exchange rate based on derivative instruments, long-term debt, and other financial instruments as at December 31, 2016. The $59.3 million increase or decrease shown above is primarily driven by US $0.9 billion notional of cross currency interest rate swaps outstanding as at December 31, 2016 and effective for January 2017.

Subsequent to December 31, 2016, Vermilion repaid $1.2 billion of borrowings on the revolving credit facility bearing interest at CDOR (Canadian Dollar Offered Rate) plus applicable margins and simultaneously borrowed US $0.9 billion on the revolving credit facility bearing interest at LIBOR plus applicable margins. As this transaction occurred subsequent to the balance sheet date, it is not included in the calculations shown in the above table. If included, the before tax effect on comprehensive income for a 5% increase/decrease in strength of the Canadian dollar against the US dollar as at December 31, 2016 would be an increase/decrease of $0.5 million.

Credit Risk:
Vermilion is exposed to credit risk on accounts receivable and derivative assets in the event that customers, joint operation partners, or counterparties fail to discharge their contractual obligations. As at December 31, 2016, Vermilion's maximum exposure to receivable credit risk was $137.2 million (December 31, 2015 - $228.8 million) which is the value of accounts receivable and derivative assets on the balance sheet.

Vermilion's accounts receivable primarily relates to customers and joint operations partners in the petroleum and natural gas industry. These amounts are subject to normal industry payment terms and credit risks. Vermilion manages these risks by monitoring the creditworthiness of customers and joint operations partners and, where appropriate, obtaining assurances such as parental guarantees and letters of credit. As at the balance sheet date, approximately 2.1% of the accounts receivable balance was outstanding for more than 90 days. Vermilion considers the balance of accounts receivable to be collectible.

Vermilion's derivative assets primarily relates to the fair value of financial instruments used as part of the Company's risk management program to mitigate the effects of changes in commodity prices on future cash flows. Vermilion manages this risk by monitoring the creditworthiness of counterparties, transacting primarily with counterparties that have investment grade third party credit ratings, and by limiting the concentration of financial exposure to individual counterparties. As a result, Vermilion has not obtained collateral or other security to support its financial derivatives.

Vermilion's cash deposited in financial institutions and guaranteed investment certificates are also subject to counterparty credit risk. Vermilion mitigates this risk by transacting with financial institutions with high third party credit ratings.

Liquidity Risk:
Liquidity risk is the risk that Vermilion will encounter difficulty in meeting obligations associated with its financial liabilities. Vermilion does not consider this to be a significant risk as its financial position and available committed borrowing facility provide significant financial flexibility and allow Vermilion to meet its obligations as they come due.

The following table summarizes Vermilion's undiscounted non-derivative financial liabilities and their contractual maturities:

($M)	1 month	1 month to 3 months	3 months to 1 year	1 year to 5 years
December 31, 2016	79,509	120,233	7,241	1,377,819
December 31, 2015	112,890	353,934	33,663	1,180,486

19. RELATED PARTY DISCLOSURES

The compensation of directors and management is reviewed annually by the independent Governance and Human Resources Committee against industry practices for oil and gas companies of similar size and scope.

The following table summarizes the compensation of directors and other members of key management personnel during the years ended December 31, 2016 and December 31, 2015:

	Year Ended	
($M)	Dec 31, 2016	Dec 31, 2015
Short-term benefits	**4,748**	5,460
Share-based payments	**20,169**	20,310
	24,917	25,770
Number of individuals included in the above amounts	**18**	20

20. SUPPLEMENTAL INFORMATION

Changes in non-cash working capital was comprised of the following:

	Year Ended	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Changes in:		
Accounts receivable	**28,780**	11,321
Crude oil inventory	**1,311**	(3,569)
Prepaid expenses	**1,762**	2,577
Accounts payable and accrued liabilities	**(67,190)**	(49,449)
Income taxes payable	**30,213**	(38,457)
Foreign exchange	**1,192**	(8,793)
Changes in non-cash working capital	**(3,932)**	(86,370)
Changes in non-cash operating working capital	**8,366**	(60,390)
Changes in non-cash investing working capital	**(12,298)**	(25,980)
Changes in non-cash working capital	**(3,932)**	(86,370)

Cash and cash equivalents was comprised of the following:

	As at	
($M)	**Dec 31, 2016**	**Dec 31, 2015**
Cash on deposit with financial institutions	**62,614**	31,175
Guaranteed investment certificates	**161**	10,501
Cash and cash equivalents	**62,775**	41,676

Wages and benefits included in operating expenses and general and administration expenses were:

	Year Ended	
($M)	**2016**	**2015**
Operating expense	**45,061**	47,738
General and administration expense	**35,347**	40,391
Wages and benefits	**80,408**	88,129

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 3, 4, 5, 6]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

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

Loren M. Leiker [6]
Houston, Texas

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

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

Anthony Marino
Calgary, Alberta

Robert Michaleski [3]
Calgary, Alberta

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

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

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

ABBREVIATIONS

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in southeast Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
btu	British thermal units
CGU	Cash generating unit, the basis upon which Vermilion's assets are evaluated for potential impairments
DRIP	Dividend Reinvestment Plan
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mboe	thousand barrel of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day

OFFICERS AND KEY PERSONNEL

CANADA
Anthony Marino
President & Chief Executive Officer

Curtis W. Hicks
Executive Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Daniel Goulet
Director Corporate HSE

Bryce Kremnica
Director Field Operations – Canada Business Unit

Kyle Preston
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

Jenson Tan
Director Business Development

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES
Daniel G. Anderson
Managing Director – U.S. Business Unit

Timothy R. Morris
Director U.S. Business Development – U.S. Business Unit

EUROPE
Gerard Schut
Vice President European Operations

Darcy Kerwin
Managing Director - France Business Unit

Scott Seatter
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

HSBC Bank Canada

Wells Fargo Bank N.A., Canadian Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

Union Bank, Canada Branch

Barclays Bank PLC

Canadian Western Bank

Goldman Sachs Lending Partners LLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

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

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

mmboe	million barrel of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom, quoted in pence per therm, at the National Balancing Point Virtual Trading Point operated by National Grid. Our production in Ireland is priced with reference to NBP.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
TTF	the day-ahead price for natural gas in the Netherlands, quoted in MWh of natural gas, at the Title Transfer Facility Virtual Trading Point operated by Dutch TSO Gas Transport Services
WTI	West Texas Intermediate, the reference price paid for

Managing Director - Australia Business Unit

EXHIBIT 99.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use of our reports dated February 24, 2017 relating to the consolidated financial statements of Vermilion Energy Inc. and subsidiaries (the "Company") and the effectiveness of the Company's internal control over financial reporting appearing in this Annual Report on Form 40-F of Vermilion Energy Inc. and subsidiaries for the year ended December 31, 2016.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
February 27, 2017

EXHIBIT 99.5

CONSENT OF INDEPENDENT ENGINEERS

We hereby consent to the use of and reference to our name and our reports, and the inclusion of information derived from our reports, evaluating Vermilion Energy Inc.'s petroleum and natural gas reserves as at December 31, 2016, in this Annual Report on Form 40-F of Vermilion Energy Inc.

Yours truly,

("GLJ Petroleum Consultants Ltd.")

GLJ Petroleum Consultants Ltd.
4100, 400 - 3rd Avenue S.W.,
Calgary, Alberta, Canada T2P 4H2
(403) 266-9500 Fax (403) 262-1855

February 27, 2017

EXHIBIT 99.6

VERMILION ENERGY INC.
CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

I, Anthony Marino, certify that:

1. I have reviewed this annual report on Form 40-F of Vermilion Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 27, 2017

("Anthony Marino")

_____

[Signature]

Anthony Marino, Chief Executive Officer

EXHIBIT 99.6

VERMILION ENERGY INC.
CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

I, Curtis Hicks, certify that:

1. I have reviewed this annual report on Form 40-F of Vermilion Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 27, 2017

("Curtis Hicks")

_____

[Signature]

Curtis Hicks, Chief Financial Officer

EXHIBIT 99.7

VERMILION ENERGY INC.
CERTIFICATE OF THE CHIEF EXECUTIVE OFFICER

Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

In connection with the annual report of Vermilion Energy Inc. (the "Corporation") on Form 40-F for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Anthony Marino, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Dated at Calgary, Alberta, Canada this 27th day of February 2017.

("Anthony Marino")

[Signature]

Anthony Marino, Chief Executive Officer

EXHIBIT 99.7

VERMILION ENERGY INC.
CERTIFICATE OF THE CHIEF FINANCIAL OFFICER

Pursuant to Section 906(a) of the Sarbanes-Oxley Act of 2002
Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18 of the United States Code

In connection with the annual report of Vermilion Energy Inc. (the "Corporation") on Form 40-F for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Curtis Hicks, Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Dated at Calgary, Alberta, Canada this 27th day of February 2017.

("Curtis Hicks")

[Signature]

Curtis Hicks, Chief Financial Officer