UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 40-F

o 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, 2017
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: **122,118,974 shares**

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the “Exchange Act”). If “Yes” is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes o 82-_____ No þ

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.

Yes þ No o

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act. Emerging growth

company ¨

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ¨

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, 2017
Exhibit 99.2 - Management's Discussion and Analysis for the fiscal year ended December 31, 2017; and
Exhibit 99.3 - Audited Annual Financial Statements for the fiscal year ended December 31, 2017

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 2017 Audited Financial Statements included as Exhibit 99.3 to this report.

C. Auditor Attestation

See page 5 of the 2017 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. In 2017, 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 59 of the Annual Information Form for the year ended December 31, 2017 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, 2017 (Cdn $000’s)

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt	21,295	42,339	947,534	429,274	1,440,442
Operating lease obligations	10,716	19,129	10,303	28	40,176
Finance lease obligations	6,680	10,207	4,665	3,351	24,903
Processing and transportation agreements	26,002	34,343	10,960	35,153	106,458
Purchase obligations	21,105	16,649	1,664	—	39,418
Drilling and service agreements	10,255	46,129	20,132	5,110	81,626
Total contractual obligations and commitments	96,053	168,796	995,258	472,916	1,733,023

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), Stephen P. Larke, Larry J. Macdonald, and Robert B. 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 28, 2018

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, 2017
99.2	Management's Discussion and Analysis from the 2017 Annual Report to Shareholders
99.3	Audited Annual Financial Statements for the Year Ended December 31, 2017
99.4	Consent of Independent Registered Public Accounting Firm
99.5	Consent of Independent Petroleum Consultants
99.6	Officers' Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
99.7	Certifications of Chief Executive Officer and Chief Financial Officer 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
101	Interactive data files

2017 ANNUAL INFORMATION FORM

For the year ended December 31, 2017

Dated February 28, 2018

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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;

"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 Vermilion Resources Ltd., previously a subsidiary of the company ("VRL"), received 1.89344 common shares for each exchangeable share held;

"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 the date on which a shareholder must hold the stock to receive the applicable dividend;

"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, 2018 and effective December 31, 2017;

"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, 2017;

"IFRS" means International Financial Reporting Standards or, alternatively, "GAAP", 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 26, 2018 (or, if adjourned, such other date on which the meeting is held);

"NYSE" means New York Stock Exchange;

"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;

"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.

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	An indication of the specific gravity of crude oil measured on the API (American Petroleum Institute) 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
AECO	the daily average benchmark price for natural gas at the AECO 'C' hub in southeast Alberta

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 and prospective 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.

"Capital expenditures" represents the sum of drilling and development and exploration and evaluation. Vermilion considers 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.

"Fund flows from operations" represents a measure of profit or loss in accordance with IFRS 8 “Operating Segments”. Vermilion analyzes 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" represents a per boe and per mcf performance measures used in the analysis of operational activities. Vermilion assesses 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.

VERMILION ENERGY INC.

General

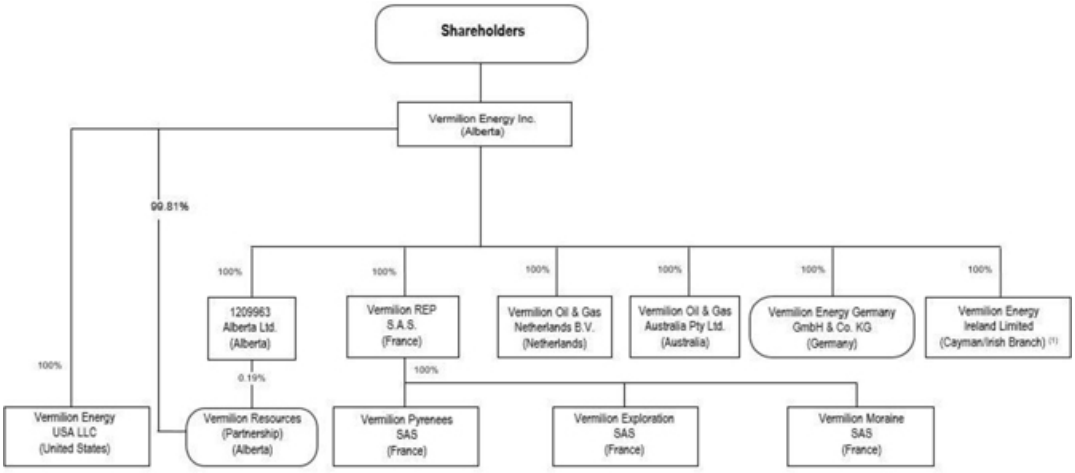
Vermilion Energy Inc. is the successor to the Trust, following the completion of the Conversion Arrangement whereby the Trust converted from an income trust to a corporate structure by way of a court approved plan of arrangement under the ABCA on September 1, 2010.

As at December 31, 2017, Vermilion had 505 full time employees of which 172 employees were located in its Calgary head office, 55 employees in its Canadian field offices, 149 employees in France, 59 employees in the Netherlands, 31 employees in Australia, 9 employees in the United States, 24 employees in Germany, 5 employees in Hungary and 1 employee in Croatia.

Vermilion 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 currently 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 Leadership Level performer by the CDP (formerly the Carbon Disclosure Project), 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 liquids rich gas producing asset is the Mannville condensate play in the West Pembina area. The Cardium light crude oil play in West Pembina is the main oil producing area, along with the Northgate and Slave Lake oil producing areas. Vermilion's main natural gas producing areas are West Pembina and Central Alberta.

Vermilion holds an average 74% working interest in approximately 445,700 (330,900 net) acres of developed land, and an average 87% working interest in approximately 430,800 (376,400 net) acres of undeveloped land. Vermilion had 523 (375 net) producing natural gas wells and 639 (475 net) producing oil wells in Canada as at December 31, 2017.

Vermilion owns and operates three natural gas plants and has an ownership interest in six 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 ten operated oil batteries including a 15,000 bbl/d oil battery in West Pembina.

For the year ended December 31, 2017, production in Canada averaged 97.9 MMcf/d of natural gas and 13,195 bbl/d of light crude oil, medium crude oil and NGLs. Sales of natural gas in 2017 were $83.5 million (2016 - $65.9 million) and sales from light crude oil, medium crude oil and NGLs were $247.3 million (2016 - $187.0 million).

During 2017, 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 2017 Vermilion drilled or participated in 24 (17.4 net) Mannville wells and production from the Mannville play increased by 42% as compared to 2016. Vermilion plans to drill 17 (13.8 net) Mannville wells in 2018. The Company also plans to drill or participate in five (4.2 net) Cardium wells and 21 (20.5 net) southeast Saskatchewan wells in 2018 as compared to seven (7.0 net) Cardium wells and 13 (11.1 net) southeast Saskatchewan wells in 2017. Vermilion expects that the Mannville, Cardium and southeast Saskatchewan assets will continue to support the Company's production growth.

The GLJ Report assigned 81,322 Mboe of total proved reserves and 139,209 Mboe of proved plus probable reserves to Vermilion's properties located in Canada as at December 31, 2017.

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. Vermilion also holds exploration lands in the Alsace-Lorraine region. The three major fields in the Paris Basin area are Champotran, Neocomian and Chaunoy, and the two major fields in the Aquitaine Basin are Parentis and Cazaux. Vermilion operates 19 oil batteries and 15 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 99% working interest in 383,000 (379,800 net) acres of undeveloped land in the Aquitaine and Paris Basins. Vermilion had 338 (332 net) producing oil wells and three (3.0 net) producing gas wells in France as at December 31, 2017.

For the year ended December 31, 2017, production in France averaged 11,085 bbl/d of light crude oil and medium crude oil. Sales from light crude oil and medium crude oil in 2017 were $268.1 million (2016 - $246.6 million) with no sales of natural gas (2016 - $0.3 million). Natural gas sales in France have decreased significantly since 2013 following the closure of a third party processing facility.

In 2017, Vermilion drilled six (6.0 net) wells in the Neocomian fields in the Paris basin, four (4.0 net) wells in the Champotran field and one (1.0 net) horizontal sidetrack well in the Vulaines field. In 2018, Vermilion intends to drill two (2.0 net) Neocomian wells and three (3.0 net) Champotran wells. 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 42,093 Mboe of total proved reserves and 64,188 Mboe of proved plus probable reserves to Vermilion's properties located in France as at December 31, 2017.

Netherlands Business Unit

Vermilion entered the Netherlands in 2004 and is the country's second largest onshore natural gas producer (excluding state-owned energy company EBN). 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 primarily of natural gas with a small amount of related condensate. Vermilion’s total land position in the Netherlands covers 1,455,800 (826,000 net) acres at an average 56% working interest, of which 95% is undeveloped. Vermilion had 56 (39 net) producing natural gas wells as at December 31, 2017.

For the year ended December 31, 2017, Vermilion's production in the Netherlands averaged 40.5 MMcf/d of natural gas and 90 bbl/d of NGLs. Sales in 2017 of natural gas were $106.2 million (2016 - $99.3 million) and sales from NGLs were $1.9 million (2016 - $1.4 million).

Vermilion drilled two (1.0 net) exploration wells in the Netherlands during 2017 and the Company expects to drill three (1.5 net) exploration wells in 2018. 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 10,347 Mboe of total proved reserves and 17,863 Mboe of proved plus probable reserves to Vermilion's properties located in the Netherlands as at December 31, 2017.

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. Vermilion had 135 (104 net) producing oil wells and 20 (7 net) producing natural gas wells as at December 31, 2017.

Vermilion holds a significant land position in northwest Germany comprised of 88,600 (32,600 net) developed acres and 2,787,000 (1,214,000 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. Furthermore, the Company holds a 50% equity interest in Hannoversche Erdölleitung GmbH ("HEG"), a joint venture company created in 1959 that collects and transports oil through a 185 km network of infrastructure from the Hannover region to rail loading facilities in Hannover.

For the year ended December 31, 2017, production in Germany averaged 19.4 MMcf/d of natural gas and 1,060 bbl/d of crude oil. Sales of natural gas in 2017 were $45.1 million (2016 - $29.0 million) and sales from crude oil were $23.6 million (2016 - nil).

During 2017, Vermilion focused on workover and optimization opportunities on the assets acquired in December 2016. In 2018, the Company plans to continue 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 2019. Vermilion will also advance permitting, studies and other activities associated with the farm-in agreement signed in mid-2015.

The GLJ Report assigned 12,640 Mboe of total proved reserves and 24,496 Mboe of proved plus probable reserves to Vermilion's properties located in Germany as at December 31, 2017.

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.

On July 12, 2017 Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership in Corrib, whereby CPPIB will acquire Shell E&P Ireland Limited's 45% interest in Corrib for total cash consideration of €830 million, subject to customary closing adjustments and future contingent value payments based on performance and realized pricing. At closing, Vermilion expects to assume operatorship of Corrib. In addition to operatorship, CPPIB plans to transfer a 1.5% working interest to Vermilion for €19.4 million ($28.4 million), before closing adjustments. Vermilion's incremental 1.5% ownership of Corrib represents production of approximately 850 boe/d (100% gas). The acquisition has an effective date of January 1, 2017 and is anticipated to close in the first half of 2018.

For the year ended December 31, 2017, production in Ireland averaged 58.4 MMcf/d of natural gas. Sales of natural gas in 2017 were $153.3 million (2016 - $109.2 million).

The GLJ Report assigned 13,634 Mboe of total proved reserves and 22,199 Mboe of proved plus probable reserves to Vermilion's property located in Ireland as at December 31, 2017.

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 182,000 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, 2017, Vermilion's production in Australia averaged 5,770 bbl/d of light crude oil and medium crude oil. Sales in 2017 from light crude oil and medium crude oil were $154.4 million (2016 - $136.8 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 expects to manage its Australian asset and related capital investment programs to maintain stable production levels of approximately 6,000 bbl/d.

The GLJ Report assigned 10,915 Mboe of total proved reserves and 15,565 Mboe of proved plus probable reserves to Vermilion's property located in Australia as at December 31, 2017.

United States Business Unit

Vermilion entered the United States in 2014. The Company's assets include 109,500 (97,200 net) acres of land in the Powder River basin of northeastern Wyoming, of which 95% is undeveloped. Vermilion had 13 (11 net) producing oil wells in the United States as at December 31, 2017.

For the year ended December 31, 2017, Vermilion’s production in the United States averaged 716 bbl/d of light crude oil, medium crude oil and NGLs and 0.4 MMcf/d of natural gas. Sales from all commodities in 2017 were $15.4 million (2016 - $7.3 million).

During 2017, Vermilion continued work on its early stage Turner Sand development in the Powder River Basin, drilling and completing three (3.0 net) wells. In 2018, Vermilion expects to drill five (5.0 net) wells in this play.

The GLJ Report assigned 5,613 Mboe of total proved reserves and 14,970 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, Slovakia and Croatia.

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

Vermilion's land position in the CEE consists of 652,800 (652,800 net) acres in Hungary, 184,600 (92,300 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.

Vermilion plans to drill its first well (1.0 net) in the South Battonya license of Hungary in 2018.

(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, 2017, 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.

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.

Vermilion maintained its dividend at $0.215 per month throughout 2015. In February 2015, Vermilion announced the implementation of a Premium Dividend^{TM} Component of the Dividend Reinvestment Plan as a short term measure to maintain the Company's financial strength. The Premium Dividend^{TM} component allowed Vermilion to preserve financial flexibility by providing ongoing access to a modest amount of low-cost equity capital. Under the Premium Dividend^{TM} component, shares were issued at 3.5% discount to average market price and participating shareholders received a premium cash payment equal to 101.5% of dividends.

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 access to key 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 our company-wide Profitability Enhancement Program ("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 totaled $242.4 million, representing decreases from 2015 and 2014 of 50% and 65%, respectively.

Vermilion maintained its dividend at $0.215 per month throughout 2016. In addition, the Company began prorating the Premium Dividend^{TM} Component of the Dividend Reinvestment Plan starting in 2016. The Premium Dividend ^{TM} Component of the Dividend Reinvestment Plan was implemented by Vermilion in 2015 as a short term measure to preserve the Company's financial flexibility by providing access to a modest amount of low-cost equity capital. As a result of the continued strength in the Company's business associated with cost reductions, capital efficiency improvements and the expectation of a more stable commodity price environment, Vermilion began prorating the Premium Dividend^{TM} Component of the Dividend Reinvestment Plan by 25% commencing with the October 2016 dividend.

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 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.

2017

Vermilion achieved record annual production of 68,021 boe/d representing an increase of 7% as compared to 2016. Production growth in Canada, the US, Ireland and Germany more than offset lower production in France, Netherlands and Australia. Permitting delays significantly reduced Netherlands production volumes in 2017, while an unplanned 31-day downtime period at Corrib late in Q3 and early Q4 2017 reduced annual production by approximately 900 boe/d.

Vermilion maintained its dividend at $0.215 per month throughout 2017. Additionally, as the Company's business continued its strong performance and with the prospect of a more stable commodity price environment, Vermilion continued the proration of the Premium Dividend^{TM} Component of the Dividend Reinvestment Plan, which commenced in 2016, throughout the year. The Company discontinued the Premium Dividend^{TM} Component beginning with the July 2017 dividend payment.

In March 2017, Vermilion issued US$300 million aggregate principal amount of eight-year senior unsecured notes bearing interest at a rate of 5.625% per annum. This issuance was completed by way of a private offering and represented Vermilion's first issuance in the US debt markets. The issuance of US dollar denominated debt provides a partial natural hedge against our largely US dollar denominated revenue streams.

In April 2017, Vermilion extended the term of its credit facility with its banking syndicate to May 2021. Following a review of the Company's projected liquidity requirements and the receipt of proceeds from the US debt issuance, Vermilion elected to request a reduction in the total facility amount to $1.4 billion from $2.0 billion.

In July 2017, Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership in Corrib, whereby CPPIB will acquire Shell E&P Ireland Limited's 45% interest in Corrib for total cash consideration of €830 million, subject to customary closing adjustments and future contingent value payments based on performance and realized pricing. At closing, Vermilion expects to assume operatorship of Corrib. In addition to operatorship, CPPIB plans to transfer a 1.5% working interest to Vermilion for €19.4 million ($28.4 million), before closing adjustments. Vermilion's incremental 1.5% ownership of Corrib represents production of approximately 850 boe/d (100% gas). The acquisition has an effective date of January 1, 2017 and is anticipated to close in the first half of 2018.

In December 2017, we were awarded a license for the Békéssámson concession for a 4-year term in Hungary. Located adjacent to our existing South Battonya concession in southeast Hungary, the Békéssámson concession covers 330,700 net acres (100% working interest) and more than doubles the size of our total land position in the country. We plan to drill our first well (1.0 net) in the South Battonya concession in Hungary in 2018.

Vermilion continued to be recognized for its commitment and leadership on environmental, social and governance matters in 2017. The Company received a top quartile ranking for our industry sector in RobecoSAM's annual Corporate Sustainability Assessment ("CSA"). The CSA analyzes sustainability performance across economic, environmental, governance and social criteria, and is the basis of the Dow Jones Sustainability Indices. The RobecoSAM assessment follows earlier recognition of Vermilion's sustainability performance, including being named to the CDP Climate Leadership Level (A-) as a global leader in environmental stewardship, and receipt of the French government's Circular Economy Award for Industrial and Regional Ecology for our geothermal energy partnership in Parentis. Vermilion was also ranked 13th by Corporate Knights on the Future 40 Responsible Corporate Leaders in Canada list. This marks the fourth year in a row that Vermilion has been recognized by Corporate Knights as one of Canada's top sustainability performers. Vermilion's MSCI ESG (Environment, Social and Governance) rating increased from BBB to A for 2017 and our Governance Metrics score ranked in the 90th percentile globally.

Outlook

Vermilion's business model continues to allow for flexibility in response to volatile commodity prices and regulatory changes, as demonstrated in 2017 through the Company's response to various permitting delays in the Netherlands to reallocate capital to other business units. Vermilion intends to maintain a low level of financial leverage and continue to fund dividends and E&D capital investment from internally generated fund flows from operations. Consistent with these objectives, in October 2017 Vermilion announced an E&D capital budget for 2018 of $315 million with corresponding production guidance of between 74,500-76,500 boe/d. In January 2018, after announcing an acquisition of a private southeast Saskatchewan light oil producer, Vermilion increased its 2018 E&D guidance to $325 million and production guidance to between 75,000-77,500 boe/d. Based on the current commodity price strip, Vermilion expects to fully fund 2018 E&D capital investment and cash dividends from fund flows from operations, with surplus cash generation primarily directed to debt reduction.

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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, 2018 with an effective date of December 31, 2017. 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, 2017 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 "B" and "C", 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 Alberta Gas Cost Allowance.

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	9,065	9,065	—	—	—	—	—	—
Canada	11,148	10,219	—	—	—	—	139,772	128,023
France	35,944	33,265	—	—	—	—	8,619	7,939
Germany	5,008	4,880	—	—	—	—	29,791	26,881
Ireland	—	—	—	—	—	—	81,803	81,803
Netherlands	—	—	—	—	—	—	37,296	24,721
United States	982	782	—	—	—	—	1,071	854
Total Proved Developed Producing	62,147	58,211	—	—	—	—	298,352	270,221

	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 [2] (Mboe)	Net [2] (Mboe)
Proved Developed Producing [3] [5] [6]								
Australia	—	—	—	—	—	—	9,065	9,065
Canada	60	56	2,330	2,153	11,215	9,102	46,057	41,026
France	—	—	—	—	—	—	37,381	34,588
Germany	—	—	—	—	—	—	9,973	9,360
Ireland	—	—	—	—	—	—	13,634	13,634
Netherlands	—	—	—	—	137	90	6,353	4,210
United States	—	—	—	—	147	117	1,308	1,041
Total Proved Developed Producing	60	56	2,330	2,153	11,499	9,309	123,771	112,924

	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 [3] [5] [7]								
Australia	350	350	—	—	—	—		
Canada	878	768	—	—	—	—	9,420	8,489
France	562	492	—	—	—	—	—	—
Germany	539	521	—	—	—	—	8,959	8,156
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	21,010	20,482
United States	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	2,329	2,131	—	—	—	—	39,389	37,127

	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 [2] (Mboe)	Net [2] (Mboe)
Proved Developed Non-Producing [3] [5] [7]								
Australia	—	—	—	—	—	—	350	350
Canada	1,079	1,025	2,360	2,200	410	309	3,431	3,029
France	—	—	—	—	—	—	562	492
Germany	—	—	—	—	—	—	2,032	1,880
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	56	54	3,558	3,468
United States	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	1,079	1,025	2,360	2,200	466	363	9,933	9,219

	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	1,500	1,500	—	—	—	—	—	—
Canada	7,634	6,929	—	—	—	—	91,104	83,603
France	4,140	3,767	—	—	—	—	64	64
Germany	241	235	—	—	—	—	2,361	1,939
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	2,620	2,620
United States	3,300	2,693	—	—	—	—	3,309	2,700
Total Proved Undeveloped	16,815	15,124	—	—	—	—	99,458	90,926

	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 [2] (Mboe)	Net [2] (Mboe)
Proved Undeveloped [3] [8]								
Australia	—	—	—	—	—	—	1,500	1,500
Canada	—	—	2,023	1,849	8,679	7,689	31,834	28,860
France	—	—	—	—	—	—	4,151	3,778
Germany	—	—	—	—	—	—	635	558
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	437	437
United States	—	—	—	—	454	370	4,306	3,513
Total Proved Undeveloped	—	—	2,023	1,849	9,133	8,059	42,863	38,646

	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	10,915	10,915	—	—	—	—	—	—
Canada	19,660	17,916	—	—	—	—	240,296	220,115
France	40,646	37,524	—	—	—	—	8,683	8,003
Germany	5,788	5,636	—	—	—	—	41,111	36,976
Ireland	—	—	—	—	—	—	81,803	81,803
Netherlands	—	—	—	—	—	—	60,926	47,823
United States	4,282	3,475	—	—	—	—	4,380	3,554
Total Proved	81,291	75,466	—	—	—	—	437,199	398,274

	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 [2] (Mboe)	Net [2] (Mboe)
Proved [3]								
Australia	—	—	—	—	—	—	10,915	10,915
Canada	1,139	1,081	6,713	6,202	20,304	17,100	81,322	72,916
France	—	—	—	—	—	—	42,093	38,858
Germany	—	—	—	—	—	—	12,640	11,799
Ireland	—	—	—	—	—	—	13,634	13,634
Netherlands	—	—	—	—	193	144	10,347	8,115
United States	—	—	—	—	601	487	5,613	4,554
Total Proved	1,139	1,081	6,713	6,202	21,098	17,731	176,564	160,791

	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	12,885	11,417	—	—	—	—	181,055	164,336
France	21,786	20,115	—	—	—	—	1,854	1,769
Germany	3,000	2,931	—	—	—	—	53,134	47,092
Ireland	—	—	—	—	—	—	51,389	51,389
Netherlands	—	—	—	—	—	—	44,380	35,383
United States	7,073	5,827	—	—	—	—	7,520	6,194
Total Probable	49,394	44,940	—	—	—	—	339,332	306,163

	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 [2] (Mboe)	Net [2] (Mboe)
Probable [4]								
Australia	—	—	—	—	—	—	4,650	4,650
Canada	214	203	3,053	2,846	14,282	12,186	57,887	51,501
France	—	—	—	—	—	—	22,095	20,410
Germany	—	—	—	—	—	—	11,856	10,780
Ireland	—	—	—	—	—	—	8,565	8,565
Netherlands	—	—	—	—	119	90	7,516	5,987
United States	—	—	—	—	1,031	849	9,357	7,708
Total Probable	214	203	3,053	2,846	15,432	13,125	121,926	109,601

	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	15,565	15,565	—	—	—	—	—	—
Canada	32,545	29,333	—	—	—	—	421,351	384,451
France	62,432	57,639	—	—	—	—	10,537	9,772
Germany	8,788	8,567	—	—	—	—	94,245	84,068
Ireland	—	—	—	—	—	—	133,192	133,192
Netherlands	—	—	—	—	—	—	105,306	83,206
United States	11,355	9,302	—	—	—	—	11,900	9,748
Total Proved Plus Probable	130,685	120,406	—	—	—	—	776,531	704,437

	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 [2] (Mboe)	Net [2] (Mboe)
Proved Plus Probable [3] [4]								
Australia	—	—	—	—	—	—	15,565	15,565
Canada	1,353	1,284	9,766	9,048	34,586	29,286	139,209	124,416
France	—	—	—	—	—	—	64,188	59,268
Germany	—	—	—	—	—	—	24,496	22,578
Ireland	—	—	—	—	—	—	22,199	22,199
Netherlands	—	—	—	—	312	234	17,863	14,102
United States	—	—	—	—	1,632	1,336	14,970	12,263
Total Proved Plus Probable	1,353	1,284	9,766	9,048	36,530	30,856	298,490	270,391

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	(17,017)	90,880	132,474	146,048	147,713	77,180	124,390	136,979	136,121	130,383
Canada	929,867	770,860	647,843	559,708	494,964	929,867	770,860	647,843	559,708	494,964
France	1,791,774	1,315,070	1,030,403	849,032	725,407	1,473,144	1,091,894	858,839	708,168	604,390
Germany	276,577	249,619	206,965	174,876	151,703	276,578	249,619	206,965	174,876	151,703
Ireland	389,204	376,115	346,327	316,408	290,143	389,204	376,115	346,327	316,408	290,143
Netherlands	48,794	60,781	66,245	68,260	68,404	48,793	60,781	66,245	68,260	68,404
United States	44,617	34,550	28,272	24,106	21,170	44,619	34,550	28,272	24,106	21,170
Total Proved Developed Producing	3,463,816	2,897,875	2,458,529	2,138,438	1,899,504	3,239,385	2,708,209	2,291,470	1,987,647	1,761,157
Proved Developed Non-Producing [2] [4] [6]										
Australia	28,079	24,122	20,869	18,180	15,942	28,079	24,122	20,869	18,180	15,942
Canada	60,804	42,405	32,416	26,238	22,048	60,804	42,405	32,417	26,238	22,048
France	10,082	8,113	6,095	4,559	3,438	6,848	5,499	3,953	2,763	1,896
Germany	49,825	37,600	27,510	20,411	15,501	32,059	29,369	23,502	18,374	14,426
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	70,140	70,244	67,599	63,916	59,989	53,099	54,167	52,375	49,452	46,205
United States	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	218,930	182,484	154,489	133,304	116,918	180,889	155,562	133,116	115,007	100,517
Proved Undeveloped [2] [7]										
Australia	54,981	43,263	34,175	27,105	21,564	25,101	18,532	13,890	10,524	8,032
Canada	524,830	354,396	246,584	175,252	126,009	397,236	281,016	202,741	148,193	108,836
France	177,851	128,923	96,156	73,638	57,592	127,650	88,876	63,091	45,660	33,460
Germany	17,161	11,696	8,012	5,495	3,737	12,154	8,910	6,412	4,551	3,166
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	10,559	8,825	7,405	6,255	5,323	7,921	6,405	5,174	4,189	3,401
United States	110,911	64,500	39,231	24,394	15,111	105,425	62,306	38,295	23,973	14,912
Total Proved Undeveloped	896,293	611,603	431,563	312,139	229,336	675,487	466,045	329,603	237,090	171,807
Proved [2]										
Australia	66,043	158,265	187,518	191,333	185,219	130,360	167,044	171,738	164,825	154,357
Canada	1,515,501	1,167,661	926,843	761,198	643,021	1,387,907	1,094,281	883,001	734,139	625,848
France	1,979,707	1,452,106	1,132,654	927,229	786,437	1,607,642	1,186,269	925,883	756,591	639,746
Germany	343,563	298,915	242,487	200,782	170,941	320,791	287,898	236,879	197,801	169,295
Ireland	389,204	376,115	346,327	316,408	290,143	389,204	376,115	346,327	316,408	290,143
Netherlands	129,493	139,850	141,249	138,431	133,716	109,813	121,353	123,794	121,901	118,010
United States	155,528	99,050	67,503	48,500	36,281	150,044	96,856	66,567	48,079	36,082
Total Proved	4,579,039	3,691,962	3,044,581	2,583,881	2,245,758	4,095,761	3,329,816	2,754,189	2,339,744	2,033,481
Probable [3]										
Australia	154,459	149,732	125,619	102,719	84,652	93,591	88,478	72,912	58,670	47,633
Canada	1,363,584	814,347	539,091	384,014	288,722	1,003,602	592,655	390,429	278,355	210,521
France	1,200,008	673,205	431,159	299,927	219,972	879,913	477,377	292,831	193,985	134,663
Germany	414,585	244,149	151,416	100,767	70,641	293,314	172,157	104,603	68,306	47,063
Ireland	350,695	246,321	182,785	141,844	114,117	350,695	246,321	182,785	141,844	114,117
Netherlands	197,136	167,242	141,871	121,179	104,496	130,277	108,388	89,527	74,196	61,980
United States	353,649	198,078	124,603	84,897	61,103	278,493	157,846	100,547	69,404	50,591
Total Probable	4,034,116	2,493,074	1,696,544	1,235,347	943,703	3,029,885	1,843,222	1,233,634	884,760	666,568

	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 Plus Probable [2] [3]										
Australia	220,502	307,997	313,137	294,052	269,871	223,951	255,522	244,650	223,495	201,990
Canada	2,879,085	1,982,008	1,465,934	1,145,212	931,743	2,391,509	1,686,936	1,273,430	1,012,494	836,369
France	3,179,715	2,125,311	1,563,813	1,227,156	1,006,409	2,487,555	1,663,646	1,218,714	950,576	774,409
Germany	758,148	543,064	393,903	301,549	241,582	614,105	460,055	341,482	266,107	216,358
Ireland	739,899	622,436	529,112	458,252	404,260	739,899	622,436	529,112	458,252	404,260
Netherlands	326,629	307,092	283,120	259,610	238,212	240,090	229,741	213,321	196,097	179,990
United States	509,177	297,128	192,106	133,397	97,384	428,537	254,702	167,114	117,483	86,673
Total Proved Plus Probable	8,613,155	6,185,036	4,741,125	3,819,228	3,189,461	7,125,646	5,173,038	3,987,823	3,224,504	2,700,049

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	978,200	—	564,074	100,883	247,200	66,043	(64,317)	130,360
Canada	3,488,501	344,924	1,118,811	412,323	96,942	1,515,501	127,594	1,387,907
France	3,591,175	272,788	997,961	125,874	214,845	1,979,707	372,065	1,607,642
Germany	853,470	44,503	298,194	20,409	146,801	343,563	22,772	320,791
Ireland	643,435	—	170,325	18,907	64,999	389,204	—	389,204
Netherlands	546,125	104,158	203,425	28,166	80,883	129,493	19,680	109,813
United States	404,551	112,559	65,468	66,993	4,003	155,528	5,484	150,044
Total Proved	10,505,457	878,932	3,418,258	773,555	855,673	4,579,039	483,278	4,095,761
Proved Plus Probable [(2) (3)]								
Australia	1,432,958	—	775,932	166,801	269,723	220,502	(3,449)	223,951
Canada	6,224,592	647,349	1,828,575	744,672	124,911	2,879,085	487,576	2,391,509
France	5,718,238	433,546	1,481,349	346,196	277,432	3,179,715	692,160	2,487,555
Germany	1,672,382	105,662	507,204	104,899	196,469	758,148	144,043	614,105
Ireland	1,113,630	—	270,554	38,178	64,999	739,899	—	739,899
Netherlands	950,074	180,041	296,854	53,369	93,181	326,629	86,539	240,090
United States	1,137,518	308,001	166,074	145,966	8,300	509,177	80,640	428,537
Total Proved Plus Probable	18,249,392	1,674,599	5,326,542	1,600,081	1,035,015	8,613,155	1,487,509	7,125,646

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]	1,764,235	27.51
Heavy Oil [3]	—	—
Conventional Natural Gas [4]	693,722	14.33
Shale Gas	122	8.56
Coal Bed Methane	450	1.25
Total Proved Developed Producing	2,458,529	21.77
Proved Developed Non-Producing		
Light Crude Oil & Medium Crude Oil [3]	43,821	18.44
Heavy Oil [3]	—	—
Conventional Natural Gas [4]	108,904	17.4
Shale Gas	984	4.54
Coal Bed Methane	780	2.13
Total Proved Developed Non-Producing	154,489	16.76
Proved Undeveloped		
Light Crude Oil & Medium Crude Oil [3]	273,008	14.16
Heavy Oil [3]	—	—
Conventional Natural Gas [4]	158,318	8.31
Shale Gas	—	—
Coal Bed Methane	237	0.77
Total Proved Undeveloped	431,563	12.04
Proved		
Light Crude Oil & Medium Crude Oil [3]	2,081,064	24.35
Heavy Oil [3]	—	—
Conventional Natural Gas [4]	960,944	12.92
Shale Gas	1,106	4.58
Coal Bed Methane	1,467	1.36
Total Proved	3,044,581	18.94
Probable		
Light Crude Oil & Medium Crude Oil [3]	1,031,625	19.21
Heavy Oil [3]	—	—
Conventional Natural Gas [4]	663,113	11.98
Shale Gas	238	5.49
Coal Bed Methane	1,568	3.31
Total Probable	1,696,544	15.48
Proved Plus Probable		
Light Crude Oil & Medium Crude Oil [3]	3,112,689	22.47
Heavy Oil [3]	—	—
Conventional Natural Gas [4]	1,624,057	12.42
Shale Gas	1,344	4.85
Coal Bed Methane	3,035	1.92
Total Proved Plus Probable	4,741,125	17.53

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/$Cdn)	Exchange Rate ($Cdn/EUR)
2017	50.88	62.78	59.90	54.16	2.16	5.63	46.67	1.60	0.77	1.46
Forecast										
2018	59.00	70.25	65.34	65.50	2.20	6.25	56.85	2.00	0.79	1.49
2019	59.00	70.25	65.34	63.50	2.54	6.50	53.46	2.00	0.79	1.46
2020	60.00	70.31	65.39	63.00	2.88	6.75	53.18	2.00	0.80	1.44
2021	66.00	72.84	67.74	66.00	3.24	7.00	54.74	2.00	0.81	1.42
2022	69.00	75.61	70.32	69.00	3.47	7.15	56.37	2.00	0.82	1.40
2023	72.00	78.31	72.83	72.00	3.58	7.30	58.31	2.00	0.83	1.39
2024	75.00	81.93	76.19	75.00	3.66	7.45	60.94	2.00	0.83	1.39
2025	78.00	85.54	79.55	78.00	3.73	7.60	63.57	2.00	0.83	1.39
2026	80.33	88.35	82.16	80.33	3.80	7.75	65.61	2.00	0.83	1.39
2027	81.88	90.22	83.90	81.88	3.88	7.90	66.96	2.00	0.83	1.39
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.83	1.39

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 2017, 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, France and Germany 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 and Germany is based on the TTF day/month-ahead index, as determined on the Title Transfer Facility Virtual Trading Point. For the year ended December 31, 2017, the average realized sales prices before hedging were $57.64 per bbl (United States) for WTI, $51.36 per bbl for Canadian-based crude oil, condensate and NGLs and $2.34 per Mcf for Canadian natural gas, $73.99 per bbl (Australia), $67.08 per bbl (France) for Brent-based crude oil, $7.19 per Mcf (Ireland), $7.18 per Mcf (Netherlands), and $6.38 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, 2017 compared to such reserves as at December 31, 2016 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, 2016	12,418	4,650	17,068	12,418	4,650	17,068	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	603	—	603	603	—	603	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(2,106)	—	(2,106)	(2,106)	—	(2,106)	—	—	—	—	—	—
At December 31, 2017	10,915	4,650	15,565	10,915	4,650	15,565	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
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, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2016	—	—	—	12,418	4,650	17,068
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	603	—	603
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(2,106)	—	(2,106)
At December 31, 2017	—	—	—	10,915	4,650	15,565

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, 2016	21,974	14,105	36,079	21,962	14,103	36,065	—	—	—	12	2	14
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	594	302	896	594	302	896	—	—	—	—	—	—
Technical Revisions	(681)	(1,542)	(2,223)	(670)	(1,540)	(2,210)	—	—	—	(11)	(2)	(13)
Acquisitions	16	4	20	16	4	20	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(48)	16	(32)	(48)	16	(32)	—	—	—	—	—	—
Production	(2,195)	—	(2,195)	(2,194)	—	(2,194)	—	—	—	(1)	—	(1)
At December 31, 2017	19,660	12,885	32,545	19,660	12,885	32,545	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
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, 2016	226,530	156,668	383,198	217,098	151,707	368,805	8,061	4,677	12,738	1,371	284	1,655
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	58,040	29,520	87,560	57,075	28,977	86,052	965	543	1,508	—	—	—
Technical Revisions	1,696	372	2,068	1,057	378	1,435	799	64	863	(160)	(70)	(230)
Acquisitions	3,452	1,113	4,565	2,686	872	3,558	766	241	1,007	—	—	—
Dispositions	(2,182)	(2,150)	(4,332)	(576)	(231)	(807)	(1,606)	(1,919)	(3,525)	—	—	—
Economic Factors	(3,658)	(1,201)	(4,859)	(2,497)	(648)	(3,145)	(1,161)	(553)	(1,714)	—	—	—
Production	(35,730)	—	(35,730)	(34,547)	—	(34,547)	(1,111)	—	(1,111)	(72)	—	(72)
At December 31, 2017	248,148	184,322	432,470	240,296	181,055	421,351	6,713	3,053	9,766	1,139	214	1,353

	Natural Gas Liquids			BOE		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2016	17,363	12,907	30,270	77,092	53,123	130,215
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	5,669	1,235	6,904	15,936	6,457	22,393
Technical Revisions	(271)	95	(176)	(668)	(1,386)	(2,054)
Acquisitions	351	113	464	942	303	1,245
Dispositions	(3)	(1)	(4)	(367)	(359)	(726)
Economic Factors	(184)	(67)	(251)	(842)	(251)	(1,093)
Production	(2,621)	—	(2,621)	(10,771)	—	(10,771)
At December 31, 2017	20,304	14,282	34,586	81,322	57,887	139,209

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, 2016	42,044	21,933	63,977	42,044	21,933	63,977	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,688	1,879	3,567	1,688	1,879	3,567	—	—	—	—	—	—
Technical Revisions	1,086	(1,912)	(826)	1,086	(1,912)	(826)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(126)	(114)	(240)	(126)	(114)	(240)	—	—	—	—	—	—
Production	(4,046)	—	(4,046)	(4,046)	—	(4,046)	—	—	—	—	—	—
At December 31, 2017	40,646	21,786	62,432	40,646	21,786	62,432	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
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, 2016	5,482	892	6,374	5,482	892	6,374	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	3,239	968	4,207	3,239	968	4,207	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(37)	(6)	(43)	(37)	(6)	(43)	—	—	—	—	—	—
Production	(1)	—	(1)	(1)	—	(1)	—	—	—	—	—	—
At December 31, 2017	8,683	1,854	10,537	8,683	1,854	10,537	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2016	—	—	—	42,958	22,082	65,040
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	1,688	1,879	3,567
Technical Revisions	—	—	—	1,625	(1,751)	(126)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(132)	(115)	(247)
Production	—	—	—	(4,046)	—	(4,046)
At December 31, 2017	—	—	—	42,093	22,095	64,188

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, 2016	5,288	2,279	7,567	5,288	2,279	7,567	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	300	275	575	300	275	575	—	—	—	—	—	—
Technical Revisions	699	480	1,179	699	480	1,179	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(112)	(34)	(146)	(112)	(34)	(146)	—	—	—	—	—	—
Production	(387)	—	(387)	(387)	—	(387)	—	—	—	—	—	—
At December 31, 2017	5,788	3,000	8,788	5,788	3,000	8,788	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
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, 2016	41,481	54,284	95,765	41,481	54,284	95,765	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	117	108	225	117	108	225	—	—	—	—	—	—
Technical Revisions	6,590	(1,027)	5,563	6,590	(1,027)	5,563	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	(231)	(231)	—	(231)	(231)	—	—	—	—	—	—
Production	(7,077)	—	(7,077)	(7,077)	—	(7,077)	—	—	—	—	—	—
At December 31, 2017	41,111	53,134	94,245	41,111	53,134	94,245	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2016	—	—	—	12,202	11,326	23,528
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	320	293	613
Technical Revisions	—	—	—	1,797	310	2,107
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(112)	(73)	(185)
Production	—	—	—	(1,567)	—	(1,567)
At December 31, 2017	—	—	—	12,640	11,856	24,496

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, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
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, 2016	99,575	50,787	150,362	99,575	50,787	150,362	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	3,553	602	4,155	3,553	602	4,155	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(21,325)	—	(21,325)	(21,325)	—	(21,325)	—	—	—	—	—	—
At December 31, 2017	81,803	51,389	133,192	81,803	51,389	133,192	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
Factors	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved + Probable (Mbbl)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved + Probable (Mboe)**
At December 31, 2016	—	—	—	16,596	8,465	25,061
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	592	100	692
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(3,554)	—	(3,554)
At December 31, 2017	—	—	—	13,634	8,565	22,199

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, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
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, 2016	62,350	43,184	105,534	62,350	43,184	105,534	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	8,163	7,807	15,970	8,163	7,807	15,970	—	—	—	—	—	—
Technical Revisions	5,232	(6,579)	(1,347)	5,232	(6,579)	(1,347)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(22)	(32)	(54)	(22)	(32)	(54)	—	—	—	—	—	—
Production	(14,797)	—	(14,797)	(14,797)	—	(14,797)	—	—	—	—	—	—
At December 31, 2017	60,926	44,380	105,306	60,926	44,380	105,306	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2016	81	63	144	10,473	7,260	17,733
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	30	21	51	1,391	1,322	2,713
Technical Revisions	115	35	150	986	(1,061)	(75)
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(4)	(5)	(9)
Production	(33)	—	(33)	(2,499)	—	(2,499)
At December 31, 2017	193	119	312	10,347	7,516	17,863

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, 2016	3,169	5,727	8,896	3,169	5,727	8,896	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,413	1,483	2,896	1,413	1,483	2,896	—	—	—	—	—	—
Technical Revisions	(49)	(133)	(182)	(49)	(133)	(182)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(9)	(4)	(13)	(9)	(4)	(13)	—	—	—	—	—	—
Production	(242)	—	(242)	(242)	—	(242)	—	—	—	—	—	—
At December 31, 2017	4,282	7,073	11,355	4,282	7,073	11,355	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
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, 2016	2,969	5,481	8,450	2,969	5,481	8,450	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,328	1,554	2,882	1,328	1,554	2,882	—	—	—	—	—	—
Technical Revisions	231	489	720	231	489	720	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(5)	(4)	(9)	(5)	(4)	(9)	—	—	—	—	—	—
Production	(143)	—	(143)	(143)	—	(143)	—	—	—	—	—	—
At December 31, 2017	4,380	7,520	11,900	4,380	7,520	11,900	—	—	—	—	—	—

	Natural Gas Liquids			BOE		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2016	412	760	1,172	4,076	7,401	11,477
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	182	213	395	1,816	1,955	3,771
Technical Revisions	28	59	87	18	7	25
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(1)	(1)	(2)	(11)	(6)	(17)
Production	(20)	—	(20)	(286)	—	(286)
At December 31, 2017	601	1,031	1,632	5,613	9,357	14,970

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, 2016	84,893	48,694	133,587	84,881	48,692	133,573	—	—	—	12	2	14
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	3,995	3,939	7,934	3,995	3,939	7,934	—	—	—	—	—	—
Technical Revisions	1,657.51	(3,107)	(1,449.49)	1,668.51	(3,105)	(1,436.49)	—	—	—	(11)	(2)	(13)
Acquisitions	16	4	20	16	4	20	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(295)	(136)	(431)	(295)	(136)	(431)	—	—	—	—	—	—
Production	(8,976)	—	(8,976)	(8,975)	—	(8,975)	—	—	—	(1)	—	(1)
At December 31, 2017	81,291	49,394	130,685	81,291	49,394	130,685	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
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, 2016	438,387	311,296	749,683	428,955	306,335	735,290	8,061	4,677	12,738	1,371	284	1,655
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	67,648	38,989	106,637	66,683	38,446	105,129	965	543	1,508	—	—	—
Technical Revisions	20,541.45	(5,175)	15,366.45	19,902.45	(5,169)	14,733.45	799	64	863	(160)	(70)	(230)
Acquisitions	3,452	1,113	4,565	2,686	872	3,558	766	241	1,007	—	—	—
Dispositions	(2,182)	(2,150)	(4,332)	(576)	(231)	(807)	(1,606)	(1,919)	(3,525)	—	—	—
Economic Factors	(3,722)	(1,474)	(5,196)	(2,561)	(921)	(3,482)	(1,161)	(553)	(1,714)	—	—	—
Production	(79,073)	—	(79,073)	(77,890)	—	(77,890)	(1,111)	—	(1,111)	(72)	—	(72)
At December 31, 2017	445,051	342,599	787,650	437,199	339,332	776,531	6,713	3,053	9,766	1,139	214	1,353

	Natural Gas Liquids			BOE		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved + Probable (Mboe)
At December 31, 2016	17,856	13,730	31,586	175,815	114,307	290,122
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	5,881	1,469	7,350	21,151	11,906	33,057
Technical Revisions	(128)	189	61	4,953	(3,781)	1,172
Acquisitions	351	113	464	942	303	1,245
Dispositions	(3)	(1)	(4)	(367)	(359)	(726)
Economic Factors	(185)	(68)	(253)	(1,101)	(450)	(1,551)
Production	(2,674)	—	(2,674)	(24,829)	—	(24,829)
At December 31, 2017	21,098	15,432	36,530	176,564	121,926	298,490

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 a level that favourably ranks the project against other projects in Vermilion's inventory. 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 2014	15,663	36,784	62,418	511,944	13,134	47,737	4,382	7,279	32,638	137,343
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
2017	2,221	16,816	36,709	99,458	—	2,023	3,988	9,133	12,327	42,862
Probable										
Prior to 2014	23,890	63,484	81,938	276,407	7,773	29,252	4,724	7,784	43,567	122,212
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
2017	4,336	28,646	38,537	197,647	—	1,055	2,802	11,455	13,561	73,217

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		
2018	11,565	11,565
2019	70,052	70,052
2020	3,026	3,026
2021	3,140	58,821
2022	3,164	3,164
Remainder	9,936	20,173
Total for all years undiscounted	100,883	166,801
Canada		
2018	136,499	150,107
2019	142,540	155,186
2020	110,461	139,784
2021	20,828	119,929
2022	622	114,329
Remainder	1,373	65,337
Total for all years undiscounted	412,323	744,672
France		
2018	30,969	52,162
2019	34,118	84,258
2020	19,848	100,335
2021	26,017	59,875
2022	4,289	24,707
Remainder	10,633	24,859
Total for all years undiscounted	125,874	346,196
Germany		
2018	2,116	5,381
2019	11,172	17,742
2020	3,162	10,590
2021	3,185	29,808
2022	124	38,918
Remainder	650	2,460
Total for all years undiscounted	20,409	104,899
Ireland		
2018	—	—
2019	1,855	1,855
2020	—	19,271
2021	—	—
2022	—	—
Remainder	17,052	17,052
Total for all years undiscounted	18,907	38,178
Netherlands		
2018	3,205	9,569
2019	12,253	13,923
2020	6,181	14,170
2021	324	4,909
2022	326	4,921
Remainder	5,877	5,877
Total for all years undiscounted	28,166	53,369

(M$)	Total Proved Estimated Using Forecast Prices and Costs	Total Proved Plus Probable Estimated Using Forecast Prices and Costs
United States		
2018	3,797	11,392
2019	28,082	39,224
2020	35,114	46,818
2021	—	48,532
2022	—	—
Remainder	—	—
Total for all years undiscounted	66,993	145,966
Total Company		
2018	188,151	240,176
2019	300,072	382,240
2020	177,792	333,994
2021	53,494	321,874
2022	8,525	186,039
Remainder	45,521	135,758
Total for all years undiscounted	773,555	1,600,081

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, 2017:

	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	480	338	161	99	523	375	339	231
Saskatchewan	159	137	28	23	—	—	2	2
Total Canada	639	475	189	123	523	375	341	233
Australia	18	18	1	1	—	—	—	—
France	338	332	95	93	—	—	3	3
Germany	135	104	38	31	20	7	5	3
Ireland	—	—	—	—	6	1	—	—
Netherlands	—	—	—	—	56	39	40	32
United States (Wyoming)	13	11	2	1	—	—	—	—
Total Vermilion	1,143	940	325	249	605	422	389	271

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, 2017:

	Acquisition Costs				
(M$)	**Proved Properties**	**Unproved Properties**	**Exploration Costs**	**Development Costs**	**Total Costs**
Australia	—	—	—	29,896	29,896
Canada	22,011	—	—	148,211	170,222
Croatia	—	—	2,764	—	2,764
France	—	—	2,294	69,026	71,320
Germany	—	—	3,366	5,710	9,076
Hungary	—	—	2,596	—	2,596
Ireland	—	—	—	544	544
Netherlands	—	—	16,468	14,956	31,424
United States	3,403	—	—	19,058	22,461
Total	25,414	—	32,103	287,401	344,918

Acreage

The following table summarizes the acreage for the year ended December 31, 2017:

	Developed [1]		Undeveloped		Total	Total
	Gross [2]	**Net [3]**	**Gross [2]**	**Net [3]**	**Gross [2][4]**	**Net [3][4]**
Australia	20,164	20,164	39,389	39,389	59,553	59,553
Canada	445,665	330,940	430,766	376,448	876,431	707,388
Croatia	—	—	2,348,984	2,348,984	2,348,984	2,348,984
France	218,110	208,858	383,050	379,813	601,160	588,671
Germany	88,603	32,662	2,787,722	1,214,962	2,876,325	1,247,624
Hungary	—	—	652,817	652,817	652,817	652,817
Ireland	7,200	1,300	—	—	7,200	1,300
Netherlands	81,328	48,848	1,374,458	777,189	1,455,786	826,037
Slovakia	—	—	184,591	92,295	184,591	92,295
United States	5,058	4,721	104,452	92,436	109,510	97,157
Total	866,128	647,493	8,306,229	5,974,333	9,172,357	6,621,826

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.

(4) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Exploration and Development Activities

The following table sets forth the number of development and exploration wells which Vermilion completed during its 2017 financial year:

	Exploration Wells		Development Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Australia				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	—	—
Canada				
Oil	—	—	20.0	18.1
Gas	—	—	24.0	17.4
Dry Holes	—	—	—	—
Total Completed	—	—	44.0	35.5
France				
Oil	—	—	7.0	7.0
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	7.0	7.0
Germany				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	—	—
Ireland				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	—	—
Netherlands				
Oil	—	—	—	—
Gas	—	—	2.0	1.0
Dry Holes	—	—	—	—
Total Completed	—	—	2.0	1.0
United States				
Oil	—	—	3.0	3.0
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Completed	—	—	3.0	3.0
Total Company				
Oil	—	—	30.0	28.1
Gas	—	—	26.0	18.4
Dry Holes	—	—	—	—
Total Completed	—	—	56.0	46.5

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, 2017:

	Properties with No Attributed Reserves	
Country	**Gross Acres (1)**	**Net Acres**
Australia	39,389	39,389
Canada	161,208	140,880
Croatia	2,348,984	2,348,984
France	272,487	270,184
Germany	2,717,434	1,184,328
Hungary	652,817	652,817
Ireland	—	—
Netherlands	1,319,359	746,033
Slovakia	184,591	92,295
United States	95,556	84,564
Total	7,791,825	5,559,474

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 31,540 (26,581 net) acres in Canada, 3,681 (3,116 net) acres in the United States, and 117,618 (117,618 net) acres in France 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, Germany, 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 $19.6 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 $27.3 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. Current income taxes in France and the Netherlands apply to taxable income after eligible deductions. In France, legislation was approved in late December 2017 to reduce current income tax rates starting in 2019. The new France tax rates are 34.4% for 2017 and 2018, 32% for 2019, 28.9% for 2020, 27.4% for 2021 and 25.8% for 2022 forward. 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 of 50%. As a function of the impact of Vermilion's tax pools, the Company does not presently pay, or is expected to pay in the foreseeable future, 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, 2017:

(M$)	Oil and Gas Assets	Tax Losses	Other	Total
Australia	266,208 (1)	—	—	266,208
Canada	914,071 (1)	517,687 (4)	20,113	1,451,871
France	332,435 (2)	10,688 (5)	—	343,123
Germany	184,549 (3)	88,712 (6)	18,878	292,139
Ireland	—	1,327,743 (4)	—	1,327,743
Netherlands	78,417 (3)	7,078	—	85,495
United States	37,022 (1)	43,305 (4)	1,783	82,110
Total	1,812,702	1,995,213	40,774	3,848,689

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) Tax losses can be carried forward at 100% against taxable income
(5) 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
(6) 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	4,474	—	—	—	—	—	—	4,474
Probable	180	—	—	—	—	—	—	180
Proved Plus Probable	4,654	—	—	—	—	—	—	4,654
Canada								
Proved	6,170	—	—	99,301	404	2,139	8,521	31,665
Probable	506	—	—	11,252	9	111	1,097	3,498
Proved Plus Probable	6,676	—	—	110,553	413	2,250	9,618	35,163
France								
Proved	11,225	—	—	1,288	—	—	—	11,440
Probable	756	—	—	11	—	—	—	758
Proved Plus Probable	11,981	—	—	1,299	—	—	—	12,198
Germany								
Proved	1,112	—	—	16,584	—	—	—	3,876
Probable	37	—	—	691	—	—	—	152
Proved Plus Probable	1,149	—	—	17,275	—	—	—	4,028
Ireland								
Proved	—	—	—	52,211	—	—	—	8,702
Probable	—	—	—	4,612	—	—	—	769
Proved Plus Probable	—	—	—	56,823	—	—	—	9,471
Netherlands								
Proved	—	—	—	44,424	—	—	154	7,558
Probable	—	—	—	6,361	—	—	19	1,079
Proved Plus Probable	—	—	—	50,785	—	—	173	8,637
United States								
Proved	578	—	—	404	—	—	55	700
Probable	273	—	—	156	—	—	22	321
Proved Plus Probable	851	—	—	560	—	—	77	1,021
Total Proved	23,559	—	—	214,212	404	2,139	8,730	68,415
Probable	1,752	—	—	23,083	9	111	1,138	6,757
Total Proved Plus Probable	25,311	—	—	237,295	413	2,250	9,868	75,172

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, 2017	Three Months Ended June 31, 2017	Three Months Ended September 31, 2017	Three Months Ended December 31, 2017
Australia				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	6,581	6,054	5,473	4,993
Conventional Natural Gas (MMcf/d)	—	—	—	—
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	77.11	71.37	66.97	83.32
Conventional Natural Gas ($/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 ($/bbl)	22.12	23.22	23.35	28.11
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	54.99	48.15	43.62	55.21
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Canada				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	5,650	6,357	6,177	5,872
Conventional Natural Gas (MMcf/d)	85.74	93.68	103.92	107.91
Natural Gas Liquids (bbl/d)	5,007	6,593	8,001	9,066
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	66.71	64.35	56.97	74.27
Conventional Natural Gas ($/Mcf)	2.99	2.83	1.84	1.88
Natural Gas Liquids ($/bbl)	41.09	37.14	36.98	42.8
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	8.29	8.22	5.46	7.04
Conventional Natural Gas ($/Mcf)	0.21	0.09	0.03	0.07
Natural Gas Liquids ($/bbl)	5.9	5.48	4.47	5.75
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.11	2.59	3.25	3.88
Conventional Natural Gas ($/Mcf)	0.22	0.19	0.17	0.15
Natural Gas Liquids ($/bbl)	1.85	1.36	1.31	1.44
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	11.41	8.23	11.05	10.51
Conventional Natural Gas ($/Mcf)	1.16	1.31	1.22	1.19
Natural Gas Liquids ($/bbl)	4.3	5.65	6.18	6.49
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	43.9	45.31	37.21	52.84
Conventional Natural Gas ($/Mcf)	1.4	1.24	0.42	0.47
Natural Gas Liquids ($/bbl)	29.04	24.65	25.02	29.12

France				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	10,834	11,368	10,918	11,215
Conventional Natural Gas (MMcf/d)	0.01	—	—	—
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	67.86	62.09	63.24	75.13
Conventional Natural Gas ($/Mcf)	1.52	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	6.06	6.1	6.12	10.11
Conventional Natural Gas ($/Mcf)	0.44	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.45	3.6	3.29	4.27
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	12.94	11.86	12.58	13.67
Conventional Natural Gas ($/Mcf)	1.18	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	45.41	40.53	41.25	47.08
Conventional Natural Gas ($/Mcf)	(0.1)	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Germany				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	989	1,047	1,054	1,148
Conventional Natural Gas (MMcf/d)	19.39	19.86	20.12	18.19
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	65.62	61.34	55.95	72.58
Conventional Natural Gas ($/Mcf)	6.95	6.09	5.5	7.07
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.67	1.25	2.43	1.72
Conventional Natural Gas ($/Mcf)	0.6	0.74	1.09	0.97
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	8.11	9.22	8.97	5.86
Conventional Natural Gas ($/Mcf)	0.44	0.65	0.39	0.35
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	16.53	20.99	12.75	30.31
Conventional Natural Gas ($/Mcf)	1.98	2.21	1.2	1.84
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	37.31	29.88	31.8	34.69
Conventional Natural Gas ($/Mcf)	3.93	2.49	2.82	3.91
Natural Gas Liquids ($/bbl)	—	—	—	—

Ireland				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (MMcf/d)	64.82	63.81	49.04	56.23
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	7.65	6.32	6.25	8.47
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)	0.21	0.22	0.28	0.29
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	0.69	0.84	1.27	0.58
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received	—	—	—	—
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	6.75	5.26	4.7	7.6
Natural Gas Liquids ($/bbl)	—	—	—	—
Netherlands				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (MMcf/d)	39.92	31.58	34.9	55.66
Natural Gas Liquids (bbl/d)	76	104	74	105
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	7.34	6.49	6.51	7.87
Natural Gas Liquids ($/bbl)	58.33	49.59	52.1	66.38
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	0.12	0.1	0.11	0.13
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	1.35	1.7	1.4	1.36
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	5.87	4.69	5	6.38
Natural Gas Liquids ($/bbl)	58.33	49.59	52.1	66.38

United States				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	365	747	880	667
Conventional Natural Gas (MMcf/d)	0.2	0.44	0.64	0.29
Natural Gas Liquids (bbl/d)	24	76	56	43
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	61.68	58.05	56.41	67.1
Conventional Natural Gas ($/Mcf)	2.48	1.55	2.07	2.48
Natural Gas Liquids ($/bbl)	25.67	14.7	24.9	42.59
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	17.2	16.18	15.44	18.4
Conventional Natural Gas ($/Mcf)	1.03	0.66	0.78	0.88
Natural Gas Liquids ($/bbl)	1.03	0.66	0.78	0.88
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	0.27	0.21
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	8.68	5.69	7.92	6.48
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	35.8	36.18	32.78	42.01
Conventional Natural Gas ($/Mcf)	1.45	0.89	1.29	1.6
Natural Gas Liquids ($/bbl)	24.64	14.04	24.12	41.71
Total				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	21,805	26,687	25,190	23,701
Conventional Natural Gas (MMcf/d)	210.07	209.36	208.62	238.28
Natural Gas Liquids (bbl/d)	5,107	6,772	8,147	9,216
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	69.5	65.06	62.01	76.21
Conventional Natural Gas ($/Mcf)	5.62	4.75	4.01	5.23
Natural Gas Liquids ($/bbl)	41.27	37.08	37.01	43.07
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	5.31	4.94	4.73	7.2
Conventional Natural Gas ($/Mcf)	0.16	0.13	0.14	0.14
Natural Gas Liquids ($/bbl)	5.82	5.38	4.45	5.71
Transportation Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.72	2.45	2.67	3.28
Conventional Natural Gas ($/Mcf)	0.19	0.21	0.19	0.17
Natural Gas Liquids ($/bbl)	1.81	1.32	1.29	1.42
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	14.76	14.29	14.7	18.13
Conventional Natural Gas ($/Mcf)	1.12	1.31	1.26	1.13
Natural Gas Liquids ($/bbl)	4.21	5.5	6.07	6.38
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	46.71	43.38	39.91	47.6
Conventional Natural Gas ($/Mcf)	4.15	3.1	2.42	3.79
Natural Gas Liquids ($/bbl)	29.43	24.88	25.2	29.56

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, 2017 are summarized in Supplemental Table 2: Hedges, included in the Company's 2017 Management's Discussion and Analysis, dated February 28, 2018, available on SEDAR at www.sedar.com, under Vermilion's SEDAR profile.

DIRECTORS AND OFFICERS

As at January 31, 2018, the directors and officers of Vermilion, as a group, beneficially owned, or controlled or directed, directly or indirectly, 4,082,950 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 eleven 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 Since January 2015, Managing Director of a group of private wealth management companies
Stephen Larke Calgary, Alberta Canada	(3) (4)	Director	2017	Since 2016, Operating Partner and Advisory Board Member, Azimuth Capital Management, a private equity fund 2005 to 2015, Managing Director and Principal, Institutional Sales, and Executive Committee Member, Peters & Co., a private investment dealer
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
Larry J. Macdonald Okotoks, Alberta Canada	(2) (3) (4) (5)	Lead Director	2002	Since March 1, 2016, Lead Director of Vermilion 2003 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 2007, Director of Canadian Oil Recovery and Remediation Enterprise, Inc., a public oil recovery and remediation company 2011 to 2017, Director of Montana Tech Foundation, an independent, non-profit organization
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) (4)	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, Direct and Chair, Compensation of 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
William Roby Katy, Texas USA	(5) (6)	Director	2017	Since 2015, Chief Executive Officer, Shepherd Energy, LLC., a private energy efficiency services company 2013 to 2014, Chief Operating Officer, Sheridan Production Company, LLC., a private oil and gas company 2000 to 2013, Senior Vice President and other management positions, Occidental Petroleum Corporation, a public oil and gas company
Catherine L. Williams Calgary, Alberta Canada	(3) (4)	Director	2015	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 2016 to 2017, Director of Enbridge Income Fund, an energy infrastructure asset investment vehicle 2015 to 2017, Director of Enbridge Pipelines Inc. and Enbridge Income Partners GP Inc., subsidiaries of Enbridge Inc., a public energy transportation company 2015 to 2017, Trustee of Enbridge Commercial Trust, a subsidiary of Enbridge Inc., a public energy transportation 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 of Vermilion 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 of Vermilion 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 of Vermilion 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 of Vermilion May 1, 2014 to March 1, 2016, Director Alberta Foothills – Canada Business Unit of Vermilion February 2013 to May 2014, Cardium / LRG Development Manager of Vermilion January 2010 to February 2013 – Cardium Development Manager of Vermilion
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
Jenson Tan Calgary, Alberta Canada	Vice President Business Development	Since October 2017, Vice President, Business Development of Vermilion July 2016 to October 2017, Director, Business Development of Vermilion July 2013 to July 2016, Director, New Ventures of Vermilion November 2010 to July 2013, Business Development Professional of Vermilion
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

Credit Ratings

The following information relating to the Company's credit ratings is provided as it relates to the Company's financing costs, liquidity and operations. Specifically, credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in certain collateralized business activities on a cost effective basis depends on the Company's credit ratings. A reduction in the current rating on the Company's debt by its rating agencies, particularly a downgrade below current ratings, or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company's ability to, and the associated costs of, (i) entering into ordinary course derivative or hedging transactions and may require the Company to post additional collateral under certain of its contracts, and (ii) entering into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

Vermilion's Rating

Standard & Poor's Ratings Services, a division of the McGraw-Hill Companies (Canada) Corporation ("S&P") has assigned a corporate credit rating of Vermilion of “BB-” with a stable outlook. S&P rates long-term corporate credit ratings by rating categories ranging from a high of "AAA" to a low of "D". The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of “positive”, “negative” or “stable” which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). An obligor rated “BB” is characterized by S&P as less vulnerable in the near term than other lower-rated obligors. However, it faces major ongoing uncertainties and exposure to adverse business, financial or economic conditions, which could lead to the obligor’s inadequate capacity to meet its financial commitments.

Moody's Investors Service ("Moody's") has assigned a corporate family rating to Vermilion of "Ba3" with a stable outlook. Moody's corporate family ratings are on a rating scale that ranges from Aaa to C, which represents the highest to lowest opinions of creditworthiness. Moody’s appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa, 3 indicating a ranking in the lower end of the generic rating category. A rating of Ba3 by Moody’s is within the fifth highest of nine categories. Obligations rated Ba3 are considered non-investment grade speculative and are subject to substantial credit risk.

The following table sets forth the ratings issued by the rating agencies noted therein as of February 28, 2018:

Rating Agency	Company Rating	Outlook	Senior Unsecured Notes
S&P	BB-	Stable	BB-
Moody's	Ba3	Stable	B2

Senior Unsecured Notes Rating

S&P has assigned a long-term issue credit rating on the senior unsecured notes due March 2025 of BB-. S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "D". The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. An obligation rated "BB" is characterized as less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions, which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. The "BB" category is the fifth highest of the ten available categories.

Moody's has assigned a long-term obligations rating on the senior unsecured notes due March 2025 of Ba3. Moody’s long-term obligations ratings are on a rating scale that ranges from Aaa to C, which represents the highest to lowest opinions of creditworthiness. Moody’s appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa, with 2 indicating a mid-range ranking within the generic rating category. A rating of B2 by Moody’s is within the sixth highest of nine categories. Obligations rated B2 are considered non-investment grade speculative and are subject to substantial credit risk.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issuer of securities. The credit ratings accorded to the Senior Unsecured Notes and the Company are not recommendations to purchase, hold or sell such securities and are not a comment upon the market price of the Company's securities or their suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A revision or withdrawal of a credit rating could have a material adverse effect on the pricing or liquidity of the Senior Unsecured Notes or the common shares in any secondary markets. Vermilion does not undertake any obligation to maintain the ratings or to advise holders of the Senior Unsecured Notes or the common shares of any change in ratings. Each agency's rating should be evaluated independently of any other agency's rating.

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, 2017 (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 has been maintained at $0.215 per common share per month since January 2014.

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 December (1)	$ 1.71
Period	**Dividend Amount for Period per Common Share**
As Vermilion Energy Inc.	
2010 – January 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 December	$ 2.58
2018 – January to February	$ 0.43
Total cash dividends since January 22, 2003	$ 34.60

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

Vermilion's Premium Dividend™ and Dividend Reinvestment Plan (the "Plan") is comprised of two different components: the Dividend Reinvestment Component and the Premium Dividend™ Component. The Premium Dividend™ Component was introduced in 2015 as a temporary measure and was discontinued beginning with the July 2017 dividend payment.

The Dividend Reinvestment Component allows eligible Shareholders who elect to participate in the Dividend Reinvestment Component to reinvest their dividends in common shares at a discount (currently 2%) to the Average Market Price (with no broker commissions or trading costs). The Plan is 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").

Participation in 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. Participation in 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 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:

2017	High	Low	Close	Volume
January	$ 57.98	$ 52.79	$ 53.68	5,456,428
February	$ 54.47	$ 50.32	$ 50.51	7,443,561
March	$ 52.48	$ 46.85	$ 49.87	8,581,629
April	$ 51.03	$ 46.62	$ 48.06	5,522,017
May	$ 50.00	$ 41.19	$ 42.27	9,858,101
June	$ 45.67	$ 40.80	$ 41.14	9,999,384
July	$ 42.77	$ 38.60	$ 41.06	8,023,621
August	$ 41.29	$ 38.33	$ 40.70	7,508,957
September	$ 46.35	$ 40.52	$ 44.35	8,522,774
October	$ 44.48	$ 41.74	$ 44.03	8,028,346
November	$ 48.47	$ 44.03	$ 45.50	7,973,483
December	$ 46.02	$ 41.38	$ 45.68	8,826,557
2018	**High**	**Low**	**Close**	**Volume**
January	$ 50.46	$ 45.74	$ 46.50	8,487,719

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 Queen's University. Ms. Williams has 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).
Stephen Larke	Yes	Yes	Mr. Larke holds a Bachelor of Commerce (Distinction) degree from the University of Calgary and is a Chartered Financial Analyst. He has over 20 years of experience in energy capital markets, including research, sales, trading and equity finance. He is currently an Operating Partner and Advisory Board member with Azimuth Capital Management, an energy-focused private equity fund based in Calgary, Alberta. From 2005 to 2015, Mr. Larke was Managing Director and Executive Committee member with Peters & Co., an independent energy investment firm based in Calgary. From 1997 to 2005, he was Vice-President and Director with TD Newcrest, serving in the role of energy equity analyst.
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, 2017 and 2016, Deloitte LLP, the auditors of the Company, received the following fees from the Company:

Item	2017	2016
Audit fees (1)	$ 1,658,920	$ 1,545,495
Audit-related fees (2)	$ 123,000	$ 18,325
Tax fees (3)	$ 34,828	$ 57,614

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, 2017 and 2016.

(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. Audit related fees increased in 2017 as a result of fees billed by Deloitte LLP for assurance and related services associated with the issuance of Vermilion's Senior Unsecured Notes.

(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, 2017, 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 28, 2018.

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, 2017. 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 Appendix A 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 Appendix A 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. Demand factors can be impacted by general economic conditions, supply chain requirements, environmental and other factors. Environmental and other factors include changes in weather, weather patterns, fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas, and technology advances in fuel economy and energy generation devices. A substantial and prolonged decline in oil and natural gas prices could have an adverse effect on Vermilion's cash flow and financial position, which could include the effect of decreasing dividends.

Reputational Risks Relating to Environmental Matters

Practices and disclosures relating to environmental matters, including climate change, are attracting increasing scrutiny by stakeholders. Vermilion’s response to addressing environmental matters can impact the Company’s reputation and affect our ability to hire and retain employees; to compete for reserve acquisitions, exploration leases, licenses and concessions; and to receive regulatory approvals required to execute our operating programs.

Changes in Tax, Royalty and Other Government Incentive Program 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.

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 licenses. 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.

Political Events and Terrorist Attacks

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by Vermilion. Political developments arising in the countries in which Vermilion operates have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction to the Company's revenue.

Vermilion's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. The long-term impact of previous terrorist attacks and the threat of future terrorist attacks on the oil and gas industry in general, and on facilities for the transportation and refinement of oil and gas in particular, is not known at this time. If any of Vermilion's properties, wells or facilities or any infrastructure on which the Company relies are the subject of a terrorist attack, such attack may have a material adverse effect on Vermilion's business, financial condition, results of operations and prospects.

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.

International Operations and Future Geographical/Industry Expansion

The operations and expertise of our management are currently focused primarily on oil and natural gas production, exploration and development in three geographical regions; North America, Europe and Australia. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

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.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is used to produce commercial quantities or oil and natural gas from reservoirs that were previously unproductive or uneconomic. Hydraulic fracturing has also featured prominently in recent political, media and activist commentary on the subject of water usage and environmental damage. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves as well as increase our costs.

With activists groups expressing concern about the impact of hydraulic fracturing on the environment and water supplies, our corporate reputation may be adversely affected by the negative public perception and public protests against hydraulic fracturing.

Concerns regarding hydraulic fracturing may result in changes in regulations that delay the development of oil and natural gas resources and adversely affect our costs of compliance and reputation. Changes in government may result in new or enhanced regulatory burdens in respect of hydraulic fracturing which could affect our business.

Reliance on Key Personnel, Management and Labour

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of our existing management team to immediate and near term operations are likely to be of central importance. In addition, the labour force in certain areas in which we operate is limited and the competition for qualified personnel in the oil and natural gas industry is intense. Vermilion expects that similar projects or expansions will proceed in the same area during the same time frame as our projects. Our projects require experienced employees, and such competition may result in increases in compensation paid to such personnel or in a lack of qualified personnel. There can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business.

Environmental Legislation

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 2017, 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.

In 2015, 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 moved to $30 per tonne on January 1, 2018, the phase-out of coal-fired power generation by 2030, a cap on oil sands production emissions 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, but does not currently anticipate material impacts on its results of operations.

In 2017, the Canadian federal government proposed a new *Greenhouse Gas Pollution Pricing Act* in response to the Paris Agreement that was ratified by Canada and other nations in October 2016. Under the new Act, 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 2019, rising by $10 per tonne each year to $50 per tonne in 2023. The federal government 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 proposed legislation is not anticipated to have a material impact on Vermilion's results of operations.

In 2017, the Minister for the Ecological and Inclusive Transition presented the Government of France's Climate Plan. As part of implementing the Climate Plan, France's Parliament passed legislation in December 2017 impacting oil and gas exploration and production on French territories. The legislation prohibits the issuance of new oil and gas exploration concessions and places restrictions on oil and gas production starting in 2040. The impact of this legislation is not anticipated to have a material impact on Vermilion's reserves in France.

Vermilion continued to be recognized for its environmental, social and governance ("ESG") initiatives in 2017. Vermilion received a top quartile ranking for 2017 for our industry sector in RobecoSAM's annual Corporate Sustainability Assessment ("CSA"). The CSA analyzes sustainability performance across economic, environmental, governance and social criteria, and is the basis of the Dow Jones Sustainability Indices. The company was also named to the CDP (formerly Carbon Disclosure Project) Climate Leadership level (A-) in 2017. Vermilion is the only Canadian energy company and one of only two North American energy companies to receive this designation, ranking us in the top 4% of energy companies globally. For more information on our ESG initiatives and performance, please see our Sustainability Report at: http://sustainability.vermilionenergy.com

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.

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.

Hedging Arrangements

From time to time, Vermilion may enter into agreements to receive fixed prices on the Company's oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that Vermilion engages in price risk management activities to protect the Company from commodity price declines, the Company may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, Vermilion's hedging arrangements may expose the Company to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangements; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time Vermilion may enter into arrangements to fix the exchange rate of Canadian to U.S. dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the U.S. dollar. However, if the Company does so and the Canadian dollar declines in value compared to the U.S. dollar, Vermilion will not benefit from the fluctuating exchange rate below the level of the derivative instrument used to manage the risk.

To the extent that risk management activities and hedging strategies are employed to address commodity prices, exchange rates, interest rates or other risks, risks associated with such activities and strategies, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate such activities and strategies, which would have a negative impact on Vermilion's results of operations, financial position, cash flows and prospects.

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.

Ineffective Internal Controls

Effective internal controls are necessary for us to provide reliable financial reports and to help prevent fraud. Although we have undertaken and will undertake a number of procedures in order to help ensure the reliability of our financial reports, including those that may be imposed on us under Canadian Securities Laws and applicable U.S. federal and state securities laws, we cannot be certain that such measures will ensure that we will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm our results of operations or cause us to fail to meet our reporting obligations. Additionally, implementing and monitoring effective internal controls can be costly. If we or our independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in our consolidated financial statements.

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.

Cost of New Technology

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and natural gas companies may have greater financial, technical and personnel resources that provide them with technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. Our inability to utilize the most advanced commercially available technology could adversely affect our business, financial condition and results of operations.

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, 2017.

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, 2017. 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 107.3 million boe (low estimate) to 253.6 million boe (high estimate), with a best estimate of 176.7 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 7.7 million boe (low estimate) to 46.1 million boe (high estimate), with a best estimate of 32.8 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, 2017 (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	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	11,918	10,818	217,576	200,317	2,081	1,977	17,879	15,803	66,407	60,337	82 %	80,740	73,403
France	13,677	12,798	940	940	—	—	—	—	13,834	12,955	87 %	15,923	14,908
Germany	—	—	19,342	16,795	—	—	—	—	3,224	2,799	77 %	4,187	3,635
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	61	61	4,647	4,647	—	—	1	1	837	837	81 %	1,038	1,038
USA	17,651	14,699	17,643	14,693	—	—	2,416	2,104	23,008	19,252	90 %	25,567	21,391
Total	43,307	38,376	260,148	237,392	2,081	1,977	20,296	17,908	107,310	96,180	84 %	127,453	114,375
Contingent (2C) - Best Estimate													
Development Pending (10)													
Australia (11)	2,440	2,440	—	—	—	—	—	—	2,440	2,440	80 %	3,050	3,050
Canada (12)	19,312	17,209	352,291	322,162	2,520	2,394	27,354	23,739	105,801	95,041	81 %	131,380	118,063
France (13)	27,054	25,229	1,245	1,245	—	—	—	—	27,262	25,437	85 %	32,027	29,891
Germany (14)	—	—	33,721	29,267	—	—	—	—	5,620	4,878	77 %	7,299	6,335
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands (15)	121	121	13,995	13,995	—	—	8	8	2,462	2,462	78 %	3,170	3,169
USA (16)	25,289	21,060	25,924	21,589	—	—	3,554	2,960	33,164	27,618	90 %	36,849	30,687
Total	74,216	66,059	427,176	388,258	2,520	2,394	30,916	26,707	176,749	157,876	83 %	213,775	191,195
Contingent (3C) - High Estimate													
Development Pending (10)													
Australia	3,280	3,280							3,280	3,280	80 %	4,100	4,100
Canada	24,079	21,133	488,328	443,399	2,943	2,796	37,617	31,953	143,575	127,452	80 %	179,355	159,116
France	43,275	40,278	1,618	1,618	—	—	—	—	43,545	40,548	84 %	51,613	48,043
Germany	—	—	62,480	54,212	—	—	—	—	10,413	9,035	77 %	13,523	11,734
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	242	242	27,237	27,237	—	—	16	16	4,798	4,798	79 %	6,100	6,097
USA	36,411	30,320	38,218	31,826	—	—	5,240	4,363	48,021	39,987	90 %	53,356	44,430
Total	107,287	95,253	617,881	558,292	2,943	2,796	42,873	36,332	253,632	225,100	82 %	308,047	273,520

Resources Project	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE		Unrisked BOE		
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	—	—	30,844	27,821	—	—	531	439	5,672	5,076	60 %	9,463	8,474
France	1,302	1,235	—	—	—	—	—	—	1,302	1,235	41 %	3,212	3,049
Germany	—	—	—	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	3,120	3,120	—	—	—	—	520	520	70 %	743	743
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	1,302	1,235	33,964	30,941	—	—	531	439	7,494	6,831	56 %	13,418	12,266
Contingent (2C) - Best Estimate													
Development Unclarified [17]													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada [18]	—	—	60,273	53,873	60,886	57,652	6,641	5,995	26,834	24,583	46 %	58,404	53,558
France [19]	2,539	2,410	—	—	—	—	—	—	2,539	2,410	45 %	5,690	5,404
Germany	—	—	1,496	1,190	—	—	—	—	249	198	35 %	711	566
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands [20]	—	—	18,678	18,104	—	—	32	16	3,145	3,033	51 %	6,134	5,912
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	2,539	2,410	80,447	73,167	60,886	57,652	6,673	6,011	32,767	30,224	46 %	70,939	65,440
Contingent (3C) - High Estimate													
Development Unclarified [17]													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	—	—	78,561	69,281	77,410	72,283	10,104	8,744	36,099	32,338	46 %	78,918	70,761
France	3,825	3,632	—	—	—	—	—	—	3,825	3,632	46 %	8,250	7,828
Germany	—	—	2,327	1,850	—	—	—	—	388	308	35 %	1,109	880
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	34,682	33,807	—	—	48	24	5,828	5,659	54 %	10,743	10,441
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	3,825	3,632	115,570	104,938	77,410	72,283	10,152	8,768	46,140	41,937	47 %	99,020	89,910

Summary of Risked Net Present Value of Future Net Revenues as at December 31, 2017 - Forecast Prices and Costs [3]

Resources Project Maturity Sub-Class (M$)	Before Income Taxes, Discounted at [5]					After Income Taxes, Discounted at [5]				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Contingent (1C) - Low Estimate [6]										
Development Pending [10]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	1,324,088	692,454	384,479	223,327	133,827	968,246	491,682	261,417	143,098	78,999
France	646,356	356,990	207,518	125,059	77,334	475,460	249,755	136,639	76,160	42,380
Germany	25,368	15,606	8,171	2,911	(697)	15,012	7,957	2,377	(1,574)	(4,234)
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	30,463	22,364	16,718	12,743	9,886	18,249	13,309	9,784	7,297	5,522
USA	705,352	353,098	190,899	109,417	65,316	553,775	277,974	149,964	85,463	50,507
Total	2,731,627	1,440,512	807,785	473,457	285,666	2,030,742	1,040,677	560,181	310,444	173,174
Contingent (2C) - Best Estimate [7]										
Development Pending [10]										
Australia [11]	81,610	50,240	31,044	19,219	11,873	17,295	7,186	1,687	(1,167)	(2,534)
Canada [12]	2,286,705	1,179,969	662,147	394,654	245,475	1,674,927	844,557	458,109	261,348	153,799
France [13]	1,414,420	759,973	439,654	268,026	170,036	1,048,109	540,491	298,625	172,711	103,017
Germany [14]	116,948	83,758	60,390	44,003	32,395	80,292	56,601	39,643	27,741	19,370
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [15]	81,618	57,215	41,025	29,997	22,252	43,748	28,728	18,805	12,189	7,679
USA [16]	1,275,912	623,677	342,983	205,348	130,725	1,004,012	492,135	270,653	161,886	102,881
Total	5,257,213	2,754,832	1,577,243	961,247	612,756	3,868,383	1,969,698	1,087,522	634,708	384,212
Contingent (3C) - High Estimate [8]										
Development Pending [10]										
Australia	162,700	104,204	67,988	45,184	30,555	54,329	31,507	18,140	10,277	5,629
Canada	3,312,383	1,649,632	923,352	557,850	354,901	2,402,861	1,167,883	630,702	364,282	219,347
France	2,463,627	1,310,231	760,541	468,396	301,212	1,827,017	934,100	520,513	306,268	186,763
Germany	302,880	217,383	159,970	120,614	92,931	212,387	151,748	110,557	82,278	62,446
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	205,065	142,394	103,727	78,262	60,611	110,555	74,368	52,017	37,485	27,588
USA	2,174,766	1,004,149	546,550	330,707	215,009	1,713,929	792,856	431,644	261,128	169,703
Total	8,621,421	4,427,993	2,562,128	1,601,013	1,055,219	6,321,078	3,152,462	1,763,573	1,061,718	671,476
Contingent (1C) - Low Estimate [6]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	53,655	21,601	9,005	3,855	1,673	41,934	16,497	6,597	2,643	1,029
France	97,733	53,885	31,470	19,270	12,266	73,554	40,473	23,562	14,377	9,118
Germany	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	13,366	8,426	5,351	3,406	2,156	6,990	3,867	1,988	855	175
USA	—	—	—	—	—	—	—	—	—	—
Total	164,754	83,912	45,826	26,531	16,095	122,478	60,837	32,147	17,875	10,322
Contingent (2C) - Best Estimate [7]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada [18]	371,151	160,012	67,074	23,472	2,109	267,364	108,714	38,845	6,527	(8,792)
France [19]	180,756	91,957	50,625	29,643	18,218	134,726	67,893	36,941	21,367	12,973
Germany	472	736	724	616	487	(353)	41	132	107	45
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [20]	101,333	60,727	37,612	23,937	15,510	58,291	33,549	19,395	11,127	6,149
USA	—	—	—	—	—	—	—	—	—	—
Total	653,712	313,432	156,035	77,668	36,324	460,028	210,197	95,313	39,128	10,375
Contingent (3C) - High Estimate [8]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	685,972	314,515	159,130	85,452	47,007	547,002	261,869	138,799	78,569	46,086
France	292,883	138,555	73,474	42,171	25,626	217,128	101,766	53,321	30,222	18,141
Germany	4,579	4,019	3,344	2,727	2,210	2,638	2,450	2,054	1,651	1,300
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	244,742	135,716	82,312	53,187	35,980	141,378	76,237	44,453	27,335	17,400
USA	—	—	—	—	—	—	—	—	—	—
Total	1,228,176	592,805	318,260	183,537	110,823	908,146	442,322	238,627	137,777	82,927

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 2017 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See ”Forecast Prices Used in Estimates” 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) 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) Risked development pending best estimate 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 risked estimated cost to bring these contingent resources on commercial production is $143 MM and the expected timeline is between 6 and 8 years. The specific contingencies for these resources are corporate commitment and development timing.

(12) Risked development pending best estimate 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 risked estimated cost to bring these contingent resources on commercial production is $1,066 MM and the expected timeline is between 3 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(13) Risked development pending best estimate 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 risked estimated cost to bring these contingent resources on commercial production is $571 MM and the expected timeline is between 3 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(14) Risked development pending best estimate 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 risked estimated cost to bring these contingent resources on commercial production is $75 MM and the expected timeline is between 2 and 4 years. The specific contingencies for these resources are corporate commitment and development timing.

(15) Risked development pending best estimate 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 risked estimated cost to bring these contingent resources on commercial production is $45 MM and the expected timeline is between 2 and 4 years. The specific contingencies for these resources are corporate commitment and development timing.

(16) Risked development pending best estimate 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 risked estimated cost to bring these contingent resources on commercial production is $380 MM and the expected timeline is between 1 and 11 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 26.8 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 $323 MM with an expected timeline of 3 to 12 years.

Edson Duvernay	Based on contingencies related to corporate commitment and development timing, economic risks associated with lower liquid yields, and capital and operating cost uncertainty, GLJ has estimated risked unclarified best estimate contingent resources at 15.5 mmboe and the risked estimated cost to bring these resources on commercial production is $242.8 MM. The expected timeline is 3 to 7 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 4.7 mmboe and the risked estimated cost to bring these resources on commercial production is $31 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 3.2 mmboe and the risked estimated cost to bring these resources on commercial production is $23 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 3.3 mmboe and the risked estimated cost to bring these resources on commercial production is $26 MM. The expected timeline is 4 to 6 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 $37 MM with an expected timeline of 7 to 8 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 7 to 9 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 $8 MM. The expected timeline is 8 to 10 years.

(20) In the Netherlands, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 3.1 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 $51 MM with an expected timeline of 8 to 10 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 1.5 mmboe and the risked estimated cost to bring these resources on commercial production is $25 MM. The expected timeline is 3 to 7 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 1.6 mmboe and the risked estimated cost to bring these resources on commercial production is $26 MM. The expected timeline is 3 to 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, 2017. 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 51.5 million boe (low estimate) to 260.4 million boe (high estimate), with a best estimate of 153.4 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, 2017 **(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	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	185	168	66,480	61,570	—	—	4,522	3,982	15,787	14,412	34 %	46,435	42,388
France	5,528	4,977	—	—	—	—	—	—	5,528	4,977	21 %	25,904	23,366
Germany	—	—	136,066	116,769	—	—	—	—	22,678	19,462	29 %	78,200	67,110
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	44,603	41,372	—	—	50	46	7,484	6,941	10 %	73,823	68,723
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	5,713	5,145	247,149	219,711	—	—	4,572	4,028	51,477	45,792	23 %	224,362	201,587
Prospective - Best Estimate													
Prospect (10)													
Australia (11)	579	579	—	—	—	—	—	—	579	579	48 %	1,206	1,206
Canada (12)	2,090	1,871	162,093	147,542	112,623	106,205	24,876	22,098	72,752	66,260	23 %	309,610	281,957
France (13)	16,335	14,636	—	—	—	—	—	—	16,335	14,636	21 %	76,358	68,393
Germany (14)	—	—	292,725	251,987	—	—	—	—	48,788	41,998	29 %	168,235	144,821
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands (15)	—	—	89,366	82,029	—	—	96	89	14,990	13,761	10 %	147,256	134,912
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	19,004	17,086	544,184	481,558	112,623	106,205	24,972	22,187	153,444	137,234	22 %	702,665	631,289
Prospective - High Estimate													
Prospect (10)													
Australia	1,462	1,462	—	—	—	—	—	—	1,462	1,462	48 %	3,046	3,046
Canada	2,684	2,383	231,682	209,203	147,282	136,241	38,134	32,553	103,979	92,510	24 %	436,843	388,697
France	35,640	32,301	—	—	—	—	—	—	35,640	32,301	23 %	156,320	141,671
Germany	—	—	554,429	479,424	—	—	—	—	92,405	79,904	29 %	318,638	275,531
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	160,271	148,815	—	—	171	159	26,883	24,962	11 %	252,881	235,491
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	39,786	36,146	946,382	837,442	147,282	136,241	38,305	32,712	260,369	231,139	22 %	1,167,728	1,044,436

Summary of Risked Net Present Value of Future Net Revenues as at December 31, 2017 - 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]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	207,770	95,938	44,659	19,798	7,252	169,908	75,170	32,207	11,777	1,780
France	238,004	131,320	76,140	46,216	29,224	187,762	102,964	59,117	35,418	22,032
Germany	368,323	169,166	74,634	29,008	6,565	252,131	112,397	44,221	11,701	(3,782)
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	274,447	125,347	68,782	42,725	28,862	145,575	61,601	29,728	15,701	8,716
USA	—	—	—	—	—	—	—	—	—	—
Total	1,088,544	521,771	264,215	137,747	71,903	755,376	352,132	165,273	74,597	28,746
Prospective (Pr2) -Best Estimate [7]										
Prospect [10]										
Australia [11]	41,338	23,669	14,015	8,555	5,365	16,344	8,905	4,999	2,884	1,705
Canada [12]	1,491,712	623,324	281,364	133,988	65,665	1,065,129	430,068	182,436	78,310	31,913
France [13]	722,008	401,287	237,931	149,181	98,046	533,938	289,739	167,209	101,849	64,935
Germany [14]	1,259,830	556,044	260,954	126,408	60,705	883,031	385,237	174,225	78,544	32,534
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [15]	664,124	319,700	187,996	124,429	88,794	358,130	165,622	92,188	57,620	38,865
USA	—	—	—	—	—	—	—	—	—	—
Total	4,179,012	1,924,024	982,260	542,561	318,575	2,856,572	1,279,571	621,057	319,207	169,952
Prospective (Pr3) -High Estimate [8]										
Prospect [10]										
Australia	136,670	74,308	43,028	26,126	16,460	57,049	30,416	17,274	10,298	6,378
Canada	2,681,315	1,109,012	521,064	267,963	146,940	1,909,850	772,257	349,756	171,101	87,888
France	1,937,405	1,011,329	573,475	347,956	223,097	1,458,826	749,093	417,797	249,512	157,614
Germany	2,751,890	1,219,651	585,356	295,653	153,056	1,969,884	858,139	400,902	194,089	93,693
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	1,355,100	675,317	411,776	281,254	206,125	738,129	360,566	214,793	143,533	103,140
USA	—	—	—	—	—	—	—	—	—	—
Total	8,862,380	4,089,617	2,134,699	1,218,952	745,678	6,133,738	2,770,471	1,400,522	768,533	448,713

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 2017 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See ”GLJ December 31, 2017 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 CoDis and the CoDev. CoDis is defined in COGEH as the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. CoDev is defined as the estimated probability that, once discovered, a known accumulation will be commercially developed.

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:

- 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.

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 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 27% and the aggregate CoDis at 88%. The corresponding chance of commerciality is 23%. Risked best estimate prospective resources have been estimated at an aggregate of 72.8 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $1061 MM. The expected development timeline is 2 to 20 years.

Edson Duvernay	Based on reservoir risk, development timing and economic risk related to capital and operating cost uncertainty, GLJ has estimated the CoDev at 19% and the CoDis at 90%. The corresponding chance of commerciality is 17%. Risked best estimate prospective resources have been estimated at 33.6 mmboe and the risked estimated cost to bring these resources on commercial production is $638 MM with an expected timeline of 7 to 14 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 9 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 6.2 mmboe and the risked estimated cost to bring these resources on commercial production is $53 MM with an expected timeline of 6 to 12 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 $66 MM. The expected development timeline is 9 to 11 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 3.3 mmboe and the risked estimated cost to bring these resources on commercial production is $60 MM with an expected timeline of 7 to 11 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 2.7 mmboe and the risked estimated cost to bring these resources on commercial production is $23 MM with an expected timeline of 15 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 MM with an expected timeline of 3 to 9 years.

(13) Prospective resources for France have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 74% and the aggregate CoDis at 28%. The corresponding chance of commerciality is 21%. Risked best estimate prospective resources have been estimated at an aggregate of 16.3. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $380 MM. The expected development timeline is 1 to 13 years.

Seebach Prospect	Based on risks associated with seal, trap, reservoir and charge along with development timing, GLJ has estimated the CoDev at 75% and the CoDis at 18%. The corresponding chance of commerciality is 14%. Risked best estimate prospective resources have been estimated at 7.8 mmboe and the risked estimated cost to bring these resources on commercial production is $40 MM with an expected timeline of 5 to 7 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 $233 MM with an expected timeline of 9 to 13 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 $35 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 $7 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 67%. The corresponding chance of commerciality is 54%. Risked best estimate prospective resources have been estimated at 0.9 mmboe and the risked estimated cost to bring these resources on commercial production is $21 MM with an expected timeline of 1 to 11 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 $14 MM with an expected timeline of 7 to 9 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 $19 MM with an expected timeline of 10 to 12 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 $7 MM with an expected timeline of 4 to 5 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 $4 MM with an expected timeline of 4 to 5 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 10%. 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 $1 MM with an expected timeline of 8 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 0.07 mmboe and the risked estimated cost to bring these resources on commercial production is $1 MM with an expected timeline of 4 to 5 years.

(14) Prospective resources for Germany have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 70% and the aggregate CoDis at 42%. The corresponding chance of commerciality is 29%. Risked best estimate prospective resources have been estimated at an aggregate of 48.8 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of 313.4 MM. The expected development timeline is 1 to 13 years.

Wisselshorst A Prospect	Based on seal and trap risk along with development timing , GLJ has estimated the CoDev at 90%, and the CoDisc at 58%. The corresponding chance of commerciality is 52%. Risked Best Estimate Prospective resources have been estimated at 13.5 mmboe and the risked estimated cost to bring these resources on commercial production is $85.5MM with an expected timeline of 2 to 9 years.
Ihlow Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 71%, and the CoDisc 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 $46.6MM with an expected timeline of 5 to 7 years.
Wisselshorst B Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 50%. The corresponding chance of commerciality is 45%. Risked Best Estimate Prospective resources have been estimated at 5.5 mmboe and the risked estimated cost to bring these resources on commercial production is $42.7MM with an expected timeline of 5 to 12 years.
Weissenmoor South	Based on reservoir and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 36%. The corresponding chance of commerciality is 32%. Risked Best Estimate Prospective resources have been estimated at 4.2 mmboe and the risked estimated cost to bring these resources on commercial production is $15.9MM with an expected timeline of 3 to 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 CoDisc 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 $16MM with an expected timeline of 8 to 9 years.
Fallingbostel	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 29%. The corresponding chance of commerciality is 26%. 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 $29.5MM with an expected timeline of 3 to 9 years.

Hellwege	Based on reservoir and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 40%. The corresponding chance of commerciality is 36%. Risked Best Estimate Prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $16.1MM with an expected timeline of 3 to 8 years.
Jeddeloh Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 38%, and the CoDisc at 32%. The corresponding chance of commerciality is 12%. Risked Best Estimate Prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $23.1MM with an expected timeline of 3 to 12 years.
Ohlendorf Prospect	Based on source and trap risk along with development timing, GLJ has estimated the CoDev at 58%, and the CoDisc 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 $11.1MM with an expected timeline of 9 to 13 years.
Uphuser Meer Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 47%, and the CoDisc at 51%. The corresponding chance of commerciality is 24%. Risked Best Estimate Prospective resources have been estimated at 1.7 mmboe and the risked estimated cost to bring these resources on commercial production is $8.3MM with an expected timeline of 6 to 7 years.

Simonswolde North Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 62%, and the CoDisc 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 $6.1MM with an expected timeline of 6 to 7 years.
Burgmoor Z5 Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 63%, and the CoDisc at 52%. The corresponding chance of commerciality is 33%. Risked Best Estimate Prospective resources have been estimated at 0.7mmboe and the risked estimated cost to bring these resources on commercial production is $1.1MM with an expected timeline of 1 year.
Widdernhausen East Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDisc at 44%. The corresponding chance of commerciality is 14%. Risked Best Estimate Prospective resources have been estimated at 0.4 mmboe and the risked estimated cost to bring these resources on commercial production is $2.7MM with an expected timeline of 7 to 12 years.
Wellie Prospect	Based on reservoir, seal and source risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDisc 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 $3.3MM with an expected timeline of 10 years.
Otterstedt Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 46%, and the CoDisc 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 $3.5MM with an expected timeline of 8 to 13 years.
Ostervesede Prospect	Based on reservoir and seal risk along with development timing, GLJ has estimated the CoDev at 23%, and the CoDisc 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 $0.7MM with an expected timeline of 7 to 10 years.

(15) Prospective resources for Netherlands have been estimated based on the factors outlined below. GLJ has estimated the aggregate CoDev at 28% and the aggregate CoDis at 39%. The corresponding chance of commerciality is 11%. Risked best estimate prospective resources have been estimated at an aggregate of 15.0 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of 127 MM with an expected timeline of 2 to 15 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 41%. The corresponding chance of commerciality is 10%. Risked best estimate prospective resources have been estimated at an aggregate of 12.1 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of 83 MM with an expected timeline of 2 to 15 years.

- Chance of discovery provided for 109 prospective reservoir targets across 91 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.
- 65 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 41% and the aggregate CoDis at 28%. The corresponding chance of commerciality is 12%. Risked best estimate prospective resources have been estimated at an aggregate of 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of$ 43 MM with an expected timeline of 2 to 12 years.

- Chance of discovery provided for 25 prospective reservoir targets across 21 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.
- 17 prospects summed probabilistically across 5 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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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 2017, 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, 2017	Australia	—	313,137	—	313,137
GLJ Petroleum Consultants	December 31, 2017	Canada	—	1,465,934	—	1,465,934
GLJ Petroleum Consultants	December 31, 2017	France	—	1,563,813	—	1,563,813
GLJ Petroleum Consultants	December 31, 2017	Germany	—	393,903	—	393,903
GLJ Petroleum Consultants	December 31, 2017	Ireland	—	529,112	—	529,112
GLJ Petroleum Consultants	December 31, 2017	Netherlands	—	283,120	—	283,120
GLJ Petroleum Consultants	December 31, 2017	USA	—	192,106	—	192,106
Total			—	4,741,125	—	4,741,125

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, 2018

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

GLJ PETROLEUM CONSULTANTS

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, 2017. 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, 2017, 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, 2017	Australia	2,440	—	31,044	31,044
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Canada	105,801	—	662,147	662,147
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	France	27,262	—	439,654	439,654
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Germany	5,620	—	60,390	60,390
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Ireland	—	—	—	—
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Netherlands	2,462	—	41,025	41,025
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	USA	33,164	—	342,983	342,983
Total				**176,749**	**—**	**1,577,243**	**1,577,243**

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	(Country or Foreign Geographic Area)	Risked Volume (Mboe)
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Australia	—
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Canada	26,834
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	France	2,539
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Germany	249
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Ireland	—
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	Netherlands	3,145
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2017	USA	—
Total				**32,767**

Prospective Resources

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	(Country or Foreign Geographic Area)	Risked Volume (Mboe)
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Australia	579
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Canada	72,752
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	France	16,335
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Germany	48,788
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Ireland	—
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	Netherlands	14,990
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2017	USA	—
Total				**153,444**

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, 2018

"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, 2017, 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, 2017.

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

"William Roby"
William Roby, Director

February 28, 2018

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.

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;
    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;
    d) any other matters the external auditor brings to the Committee's attention; and
    e) 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

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

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.

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
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
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mcf	thousand cubic feet
mmbtu	million British thermal units
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 28, 2018, 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, 2017 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, 2017 and 2016, 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, 2017 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.

CONDENSATE PRESENTATION

We report our condensate production in Canada and the Netherlands business units 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).

2017 REVIEW AND 2018 GUIDANCE

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. On July 26, 2017 we announced an increase in our capital expenditure guidance from $295 million to $315 million following the acceleration of 2018 activities in our Canadian business unit. We also adjusted our 2017 annual production guidance on October 30, 2017 to 68,000-69,000 boe/d to reflect an extended downtime period following a plant turnaround at our Corrib asset in Ireland. Actual 2017 capital spending of $320 million was within 2% of our guidance and 2017 production of 68,021 boe/d modestly exceeded the bottom end of our guidance range.

On October 30, 2017, we released our 2018 capital expenditure guidance of $315 million and associated production guidance of between 74,500-76,500 boe/d. On January 15, 2018, we increased our capital expenditure guidance to $325 million and production guidance to between 75,000-77,500 boe/d to reflect the post-closing impact of the acquisition of a private southeast Saskatchewan and southwest Manitoba light oil producer.

The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2017 Guidance			
2017 Guidance	October 31, 2016	295	69,000 to 70,000
2017 Guidance	July 26, 2017	315	69,000 to 70,000
2017 Guidance	October 30, 2017	315	68,000 to 69,000
2017 Actual Results		320	68,021
2018 Guidance			
2018 Guidance	October 30, 2017	315	74,500 to 76,500
2018 Guidance	January 15, 2018	325	75,000 to 77,500

CONSOLIDATED RESULTS OVERVIEW

	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2017	**Sep 30, 2017**	**Dec 31, 2016**	**Q4/17 vs. Q3/17**	**Q4/17 vs. Q4/16**	**Dec 31, 2017**	**Dec 31, 2016**	**2017 vs. 2016**
Production								
Crude oil and condensate (bbls/d)	**27,830**	27,687	25,972	1%	7%	**27,721**	27,852	—%
NGLs (bbls/d)	**5,279**	4,947	2,467	7%	114%	**4,194**	2,582	62%
Natural gas (mmcf/d)	**238.27**	208.63	194.54	14%	22%	**216.64**	198.55	9%
Total (boe/d)	**72,821**	67,403	60,863	8%	20%	**68,021**	63,526	7%
Sales								
Crude oil and condensate (bbls/d)	**27,638**	28,391	26,610	(3)%	4%	**27,483**	28,005	(2)%
NGLs (bbls/d)	**5,279**	4,946	2,467	7%	114%	**4,194**	2,582	62%
Natural gas (mmcf/d)	**238.27**	208.63	194.54	14%	22%	**216.64**	198.55	9%
Total (boe/d)	**72,628**	68,108	61,501	7%	18%	**67,784**	63,679	6%
Build (draw) in inventory (mbbls)	**18**	(64)	(58)			**87**	(55)	
Financial metrics								
Fund flows from operations ($M)	**181,253**	130,755	149,582	39%	21%	**602,565**	510,791	18%
Per share ($/basic share)	**1.49**	1.08	1.27	38%	17%	**5.00**	4.41	13%
Net earnings (loss)	**8,645**	(39,191)	(4,032)	N/A	N/A	**62,258**	(160,051)	N/A
Per share ($/basic share)	**0.07**	(0.32)	(0.03)	N/A	N/A	**0.52**	(1.38)	N/A
Net debt ($M)	**1,371,790**	1,370,995	1,427,148	—%	(4)%	**1,371,790**	1,427,148	(4)%
Cash dividends ($/share)	**0.645**	0.645	0.645	—%	—%	**2.580**	2.580	—%
Activity								
Capital expenditures ($M)	**74,303**	91,382	66,882	(19)%	11%	**320,449**	242,408	32%
Acquisitions ($M)	**3,048**	20,976	78,713	(85)%	(96)%	**27,637**	98,524	(72)%
Gross wells drilled	**8.00**	17.00	16.00			**56.00**	38.00	
Net wells drilled	**6.00**	13.77	12.02			**46.58**	25.50	

Operational review

- Consolidated average production during Q4 2017 increased 8% to 72,821 boe/d versus Q3 2017 due to production increases in the Netherlands, Canada, and Ireland. In the Netherlands, production growth was positively impacted by the approval of a production rate increase on two of our key pools and production from a new well drilled in Q3 2017. In Canada, increased production was driven by continued organic growth from our Mannville condensate-rich resource play. In Ireland, production growth was the result of reduced downtime at the Corrib project.
- Consolidated average production increased by 20% and 7% for the three months and year ended December 31, 2017, versus the comparable periods in 2016, respectively. Year-over-year production increases were primarily driven by continued organic production growth from our Mannville condensate-rich resource play in Canada and incremental volumes from our acquisition in Germany in late 2016.
- For the three months ended December 31, 2017, capital expenditures of $74.3 million primarily related to activity in Canada, France, and the Netherlands. In Canada, capital expenditures of $26.9 million included the drilling of 6.0 (4.0 net) wells in the Mannville. In France, capital expenditures of $20.0 million included the drilling of 2.0 (2.0 net) wells in the Neocomian. In the Netherlands, capital expenditures of $12.3 million included the acquisition of 315 square kilometers of 3D seismic.

Financial review

Net earnings

- Net earnings for Q4 2017 of $8.6 million ($0.07/basic share) compared to a net loss of $39.2 million ($0.32/basic share) in Q3 2017. The net earnings in Q4 2017 largely resulted from higher revenues due to increased production volumes and stronger crude oil and European natural gas prices. In addition, net earnings in Q4 2017 benefited from an unrealized foreign exchange gain of $40.7 million, compared to an unrealized loss of $3.0 million in Q3 2017. These favourable variances were partially offset by an $80.0 million unrealized loss on derivative instruments in Q4 2017, compared to an unrealized loss of $24.2 million in the prior quarter.
- Unrealized losses and gains on derivative instruments result from mark-to-market accounting based on prevailing commodity prices at each period end. As a result, unrealized gains and losses for all derivative instruments are recognized in current period earnings based on current forward price curves, while the instruments themselves reduce Vermilion's exposure to commodity price volatility in future periods.
- Net earnings for the three months and year ended December 31, 2017 of $8.6 million ($0.07/basic share) and $62.3 million ($0.52/basic share) compare to net losses of $4.0 million ($0.03/basic share) and $160.1 million ($1.38/basic share) in the comparative periods in 2016. The net earnings in the current year largely resulted from higher revenues due to increased production volumes and stronger crude oil and European natural gas prices. In addition, net earnings benefited from unrealized foreign exchange gains of $40.7 million and $71.7 million for the three months and year ended December 31, 2017, compared to unrealized losses of $2.5 million and $0.8 million in the respective comparative periods. For the year ended December 31, 2017, these favourable variances were coupled with a smaller unrealized loss on derivative instruments of $1.1 million (compared to an unrealized loss of $138.0 million 2016) and lower depletion and depreciation charges.

Fund flows from operations

- Generated fund flows from operations of $181.3 million during Q4 2017, an increase of 39% from Q3 2017. This quarter-over-quarter increase was driven by higher crude oil and European natural gas prices and higher sales volumes. In addition, Q4 2017 fund flows from operations benefited from lower taxes, primarily in the Netherlands as a result of an increased tax deduction for future asset retirement obligations resulting from a reduction in applicable discount rate assumptions.
- Fund flows from operations increased by 21% for the three months ended December 31, 2017 versus 2016 primarily due to a 20% increase in production and a 3% increase in realized pricing. For the year ended December 31, 2017, fund flows from operations increased 18% from 2016 primarily as a result of higher production and higher realized pricing while maintaining per unit operating expenses at a level consistent with 2016.

Net debt

- Net debt decreased to $1.37 billion as at December 31, 2017 from $1.43 billion at December 31, 2016 as fund flows from operations generated in excess of capital expenditures, acquisitions, and net dividends was used to reduce long-term debt.

Dividends

- Declared dividends of $0.215 per common share per month during the year ended December 31, 2017 ($2.58 per common share for the year).

COMMODITY PRICES

	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2017	**Sep 30, 2017**	**Dec 31, 2016**	**Q4/17 vs. Q3/17**	**Q4/17 vs. Q4/16**	**Dec 31, 2017**	**Dec 31, 2016**	**2017 vs. 2016**
Average reference prices								
Crude oil								
WTI ($/bbl)	**70.43**	60.37	65.75	17%	7%	**66.13**	57.42	15%
WTI (US $/bbl)	**55.40**	48.20	49.29	15%	12%	**50.95**	43.32	18%
Edmonton Sweet index ($/bbl)	**68.98**	56.76	61.60	22%	12%	**62.94**	53.17	18%
Edmonton Sweet index (US $/bbl)	**54.26**	45.32	46.18	20%	17%	**48.49**	40.11	21%
Dated Brent ($/bbl)	**78.05**	65.22	65.97	20%	18%	**70.44**	57.92	22%
Dated Brent (US $/bbl)	**61.39**	52.08	49.46	18%	24%	**54.27**	43.69	24%
Natural gas								
AECO ($/mmbtu)	**1.69**	1.45	3.09	17%	(45)%	**2.16**	2.16	—%
NBP ($/mmbtu)	**8.70**	6.78	7.51	28%	16%	**7.49**	6.15	22%
NBP (€/mmbtu)	**5.81**	4.61	5.22	26%	11%	**5.12**	4.19	22%
TTF ($/mmbtu)	**8.36**	6.93	7.21	21%	16%	**7.43**	6.00	24%
TTF (€/mmbtu)	**5.58**	4.71	5.01	18%	11%	**5.07**	4.09	24%
Henry Hub ($/mmbtu)	**3.73**	3.76	3.98	(1)%	(6)%	**4.04**	3.27	24%
Henry Hub (US $/mmbtu)	**2.93**	3.00	2.98	(2)%	(2)%	**3.11**	2.46	26%
Average exchange rates								
CDN $/US $	**1.27**	1.25	1.33	2%	(5)%	**1.30**	1.33	(2)%
CDN $/Euro	**1.50**	1.47	1.44	2%	4%	**1.46**	1.47	(1)%
Realized Prices								
Crude oil and condensate ($/bbl)	**74.12**	61.47	64.51	21%	15%	**67.00**	55.42	21%
NGLs ($/bbl)	**29.28**	23.96	18.13	22%	62%	**25.00**	11.70	114%
Natural gas ($/mmbtu)	**5.23**	4.01	5.47	30%	(4)%	**4.91**	4.18	17%
Total ($/boe)	**47.49**	39.66	45.93	20%	3%	**44.41**	37.88	17%

Crude Oil

- Q4 2017 was a stronger quarter for crude oil prices with WTI and Dated Brent increasing by 15% and 18% versus the previous quarter. The increase in crude oil prices during Q4 2017 was largely due to continued indicators of supply and demand rebalancing through inventory draws in addition to the extension of the OPEC and non-OPEC coordinated production reductions until the end of 2018.
- During Q4 2017, Dated Brent crude oil averaged a premium to WTI of US$5.99/bbl and a premium to the Edmonton Sweet index of US$7.13/bbl. Approximately 63% of our crude oil and condensate production during Q4 2017 benefited from this premium pricing. As a result, our fourth quarter consolidated crude oil and condensate price of $74.12/bbl was $3.69/bbl higher than the Canadian dollar WTI average price and $5.14/bbl higher than the Canadian dollar Edmonton Sweet index price, representing premiums of 5% and 7%.

Natural Gas

- Cold weather in North America at the end of 2017 helped AECO gas prices increase 17% above the average price for Q3 2017. However, despite the late-year increase, AECO prices remain weak, averaging $1.69/mmbtu in Q4 2017 (45% below the same period the previous year).
- Supportive weather, supply disruptions, and strong Asian LNG demand all helped to boost European gas prices during Q4 2017. Both TTF and NBP markets benefited from increased demand for LNG in Asia where consumption growth has exceeded expectations and is offsetting the continued growth in global liquefaction capacity. As a result, NBP averaged $8.70/mmbtu in Q4 2017, an increase of 28% over Q3 2017 and a 16% increase year-over-year. Similarly, TTF averaged $8.36/mmbtu in Q4 2017, a 21% increase over Q3 2017 and a 16% increase year-over-year.
- During Q4 2017, average European gas prices were $8.53/mmbtu, which reflects a $6.84/mmbtu premium to AECO and a $4.80/mmbtu premium to Henry Hub pricing. We receive this premium pricing on our natural gas production in Europe, which made up nearly 55% of our total company natural gas production during Q4 2017. As a result, our Q4 2017 consolidated natural gas realized price of $5.23/mmbtu represented a $3.54/mmbtu premium to AECO and a $1.50/mmbtu premium to Henry Hub Pricing.

Foreign Exchange

- While the Canadian dollar weakened slightly versus the US dollar during Q4 2017, it has generally increased in strength throughout 2017.
- The Euro also posted small gains versus the Canadian dollar during the Q4 2017, following a general increase in strength throughout 2017.

FUND FLOWS FROM OPERATIONS

	Three Months Ended						Year Ended			
	Dec 31, 2017		Sep 30, 2017		Dec 31, 2016		Dec 31, 2017		Dec 31, 2016	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**317,341**	**47.49**	248,505	39.66	259,891	45.93	**1,098,838**	**44.41**	882,791	37.88
Royalties	**(23,541)**	**(3.52)**	(16,994)	(2.71)	(14,999)	(2.65)	**(74,476)**	**(3.01)**	(54,284)	(2.33)
Petroleum and natural gas revenues	**293,800**	**43.97**	231,511	36.95	244,892	43.28	**1,024,362**	**41.40**	828,507	35.55
Transportation	**(11,986)**	**(1.79)**	(10,800)	(1.72)	(9,565)	(1.69)	**(43,448)**	**(1.76)**	(39,511)	(1.70)
Operating	**(65,240)**	**(9.76)**	(61,832)	(9.87)	(59,616)	(10.54)	**(242,267)**	**(9.79)**	(222,185)	(9.53)
General and administration	**(15,941)**	**(2.39)**	(12,114)	(1.93)	(11,464)	(2.03)	**(54,373)**	**(2.20)**	(52,829)	(2.27)
PRRT	**(3,572)**	**(0.53)**	(4,345)	(0.69)	(1,568)	(0.28)	**(19,819)**	**(0.80)**	(1,568)	(0.07)
Corporate income taxes	**2,330**	**0.35**	(3,092)	(0.49)	(5,840)	(1.03)	**(12,288)**	**(0.50)**	(18,110)	(0.78)
Interest expense	**(13,710)**	**(2.05)**	(13,400)	(2.14)	(14,410)	(2.55)	**(57,313)**	**(2.32)**	(56,957)	(2.44)
Realized (loss) gain on derivative instruments	**(7,493)**	**(1.12)**	8,723	1.39	1,920	0.34	**4,721**	**0.19**	65,376	2.81
Realized foreign exchange gain (loss)	**2,899**	**0.43**	(4,110)	(0.66)	1,291	0.23	**2,316**	**0.09**	4,041	0.17
Realized other income	**166**	**0.02**	214	0.03	3,942	0.70	**674**	**0.03**	4,027	0.17
Fund flows from operations	**181,253**	**27.13**	130,755	20.87	149,582	26.43	**602,565**	**24.34**	510,791	21.91

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

($M)	Q4/17 vs. Q3/17	Q4/17 vs. Q4/16	2017 vs. 2016
Fund flows from operations – Comparative period	**130,755**	**149,582**	**510,791**
Sales volume variance:			
Canada	3,859	30,891	33,420
France	211	(4,828)	(25,361)
Netherlands	12,554	9,324	(15,383)
Germany	(1,012)	8,964	32,216
Ireland	4,090	(4,573)	15,812
Australia	(6,252)	(8,446)	(10,948)
United States	(1,189)	1,719	5,060
Pricing variance on sales volumes:			
WTI	13,785	5,249	40,279
AECO	408	(11,601)	7,318
Dated Brent	21,168	17,860	75,105
TTF and NBP	21,214	12,891	58,529
Changes in:			
Royalties	(6,547)	(8,542)	(20,192)
Transportation	(1,186)	(2,421)	(3,937)
Operating	(3,408)	(5,624)	(20,082)
General and administration	(3,827)	(4,477)	(1,544)
PRRT	773	(2,004)	(18,251)
Corporate income taxes	5,422	8,170	5,822
Interest	(310)	700	(356)
Realized derivatives	(16,216)	(9,413)	(60,655)
Realized foreign exchange	7,009	1,608	(1,725)
Realized other income	(48)	(3,776)	(3,353)
Fund flows from operations – Current period	**181,253**	**181,253**	**602,565**

Please see CONSOLIDATED RESULTS OVERVIEW for a discussion of the key variances for the periods presented.

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
- Southeast Saskatchewan light oil development:
  - Primary target is the Mississippian Midale formation (1,400 - 1,700m depth)
  - Secondary targets of Mississippian Frobisher (1,400 - 1,700m depth) and Devonian Bakken/Three Forks (2,000 - 2,100m depth)

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Canada business unit ($M except as indicated)	**Dec 31, 2017**	**Sep 30, 2017**	**Dec 31, 2016**	**Q4/17 vs. Q3/17**	**Q4/17 vs. Q4/16**	**Dec 31, 2017**	**Dec 31, 2016**	**2017 vs. 2016**
Production and sales								
Crude oil and condensate (bbls/d)	**9,703**	9,288	7,945	4%	22%	**9,051**	9,171	(1)%
NGLs (bbls/d)	**5,235**	4,891	2,444	7%	114%	**4,144**	2,552	62%
Natural gas (mmcf/d)	**107.91**	103.92	75.12	4%	44%	**97.89**	84.29	16%
Total (boe/d)	**32,923**	31,499	22,910	5%	44%	**29,510**	25,771	15%
Production mix (% of total)								
Crude oil and condensate	**29%**	29%	35%			**31%**	36%	
NGLs	**16%**	16%	11%			**14%**	10%	
Natural gas	**55%**	55%	54%			**55%**	54%	
Activity								
Capital expenditures	**26,865**	43,746	16,895	(39)%	59%	**148,667**	62,706	137%
Acquisitions	**788**	19,712	1,378			**22,011**	13,309	
Gross wells drilled	**6.00**	15.00	11.00			**44.00**	29.00	
Net wells drilled	**4.00**	12.75	7.02			**35.56**	17.62	
Financial results								
Sales	**94,522**	77,238	70,573	22%	34%	**330,903**	252,867	31%
Royalties	**(9,301)**	(6,653)	(7,390)	40%	26%	**(33,258)**	(21,475)	55%
Transportation	**(4,836)**	(4,485)	(3,504)	8%	38%	**(17,368)**	(15,392)	13%
Operating	**(22,356)**	(22,071)	(18,161)	1%	23%	**(80,444)**	(71,543)	12%
General and administration	**(2,540)**	(2,239)	(2,035)	13%	25%	**(9,604)**	(11,826)	(19)%
Fund flows from operations	**55,489**	41,790	39,483	33%	41%	**190,229**	132,631	43%
Netbacks ($/boe)								
Sales	**31.21**	26.65	33.48	17%	(7)%	**30.72**	26.81	15%
Royalties	**(3.07)**	(2.30)	(3.51)	33%	(13)%	**(3.09)**	(2.28)	36%
Transportation	**(1.60)**	(1.55)	(1.66)	3%	(4)%	**(1.61)**	(1.63)	(1)%
Operating	**(7.38)**	(7.62)	(8.62)	(3)%	(14)%	**(7.47)**	(7.59)	(2)%
General and administration	**(0.84)**	(0.77)	(0.97)	9%	(13)%	**(0.89)**	(1.25)	(29)%
Fund flows from operations netback	**18.32**	14.41	18.72	27%	(2)%	**17.66**	14.06	26%
Realized prices								
Crude oil and condensate ($/bbl)	**69.20**	57.15	62.13	21%	11%	**63.41**	52.44	21%
NGLs ($/bbl)	**29.18**	23.93	18.12	22%	61%	**25.00**	11.75	113%
Natural gas ($/mmbtu)	**1.88**	1.84	3.05	2%	(38)%	**2.34**	2.14	9%
Total ($/boe)	**31.21**	26.65	33.48	17%	(7)%	**30.72**	26.81	15%
Reference prices								
WTI (US $/bbl)	**55.40**	48.20	49.29	15%	12%	**50.95**	43.32	18%
Edmonton Sweet index (US $/bbl)	**54.26**	45.32	46.18	20%	17%	**48.49**	40.11	21%
Edmonton Sweet index ($/bbl)	**68.98**	56.76	61.60	22%	12%	**62.94**	53.17	18%
AECO ($/mmbtu)	**1.69**	1.45	3.09	17%	(45)%	**2.16**	2.16	—%

Production
- Q4 2017 average production increased by 5% from Q3 2017, and 44% year-over-year primarily due to organic production growth in our Mannville condensate-rich gas resource play.
- Mannville production averaged approximately 19,000 boe/d in Q4 2017, representing a 10% increase quarter-over-quarter. Full year 2017 production averaged more than 15,800 boe/d.
- Cardium production averaged approximately 5,400 boe/d in Q4 2017, a decrease of 7% quarter-over-quarter. Full year 2017 production averaged nearly 5,700 boe/d.
- Production from southeast Saskatchewan averaged approximately 2,500 boe/d in Q4 2017, a decrease of 4% quarter-over-quarter.

Activity review
- Vermilion drilled or participated in the drilling of six (4.0 net) wells during Q4 2017. During 2017, Vermilion drilled or participated in the drilling of 44 (35.6 net) wells in Canada

  Mannville
  - During Q4 2017, we drilled or participated in the drilling of six (4.0 net) wells and brought nine (5.5 net) wells on production.
  - We have drilled or participated in the drilling of 24 (17.5 net) wells in 2017. We plan to drill or participate in 17 (13.8 net) wells in 2018.

  Cardium
  - In 2017, we drilled seven (7.0 net) operated wells.
  - In 2018, we plan to drill or participate in five (4.2 net) wells.

  Saskatchewan
  - In 2017, we drilled 13 (11.1 net) wells.
  - In 2018, we plan to drill or participate in 21 (20.5 net) wells, which includes the planned drilling of an additional five (5.0 net) wells associated with our acquisition of a private southeast Saskatchewan and southwest Manitoba light oil producer in Q1 2018.

- On February 15, 2018, Vermilion acquired all of the issued and outstanding shares of a private producer with assets in southeast Saskatchewan and southwest Manitoba. The acquisition is comprised of light oil producing fields near Vermilion's existing operations in southeast Saskatchewan. Total consideration of $90.8 million, which includes both cash paid to the shareholders' of the acquiree and the assumption of the acquiree's long-term debt, was funded through Vermilion's revolving credit facility.

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 2017 sales per boe increased compared to Q3 2017, driven by higher crude oil and natural gas pricing.
- Sales per boe decreased for the three months ended December 31, 2017 versus the comparable period in the prior year, driven by lower natural gas pricing but partially offset by higher crude oil pricing. For the year ended December 31, 2017, relatively flat natural gas pricing was coupled with higher crude oil pricing, resulting in an increase to sales per boe compared to 2016.

Royalties
- Fluctuations in royalties for all comparable periods were primarily due to the impact of commodity prices on the sliding scale used to determine royalty rates.

Transportation
- Transportation expense relates to the delivery of crude oil and natural gas production to major pipelines where legal title transfers.
- Transportation expense on a per unit basis was consistent versus all comparable periods.

Operating
- In Q4 2017, operating expense on a per unit and dollar basis was consistent as compared to Q3 2017.
- For the three months and year ended December 31, 2017, operating expense on a dollar basis increased versus the comparable periods in the prior year due to higher gas processing costs resulting from higher production volumes. On a per unit basis, operating expense for the three months and year ended December 31, 2017 decreased versus the comparable periods in 2016 due to the impact of spreading fixed costs over higher volumes.

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 ($M except as indicated)	**Dec 31, 2017**	**Sep 30, 2017**	**Dec 31, 2016**	**Q4/17 vs. Q3/17**	**Q4/17 vs. Q4/16**	**Dec 31, 2017**	**Dec 31, 2016**	**2017 vs. 2016**
Production								
Crude oil (bbls/d)	**11,215**	10,918	11,220	3%	—%	**11,084**	11,896	(7)%
Natural gas (mmcf/d)	**—**	—	0.38	—%	(100)%	**—**	0.44	(100)%
Total (boe/d)	**11,215**	10,918	11,283	3%	(1)%	**11,085**	11,970	(7)%
Sales								
Crude oil (bbls/d)	**11,397**	11,360	12,209	—%	(7)%	**10,950**	12,157	(10)%
Natural gas (mmcf/d)	**—**	—	0.38	—%	(100)%	**—**	0.44	(100)%
Total (boe/d)	**11,397**	11,360	12,272	—%	(7)%	**10,950**	12,231	(10)%
Inventory (mbbls)								
Opening crude oil inventory	**214**	254	239			**148**	243	
Crude oil production	**1,032**	1,004	1,032			**4,046**	4,354	
Crude oil sales	**(1,049)**	(1,044)	(1,123)			**(3,997)**	(4,449)	
Closing crude oil inventory	**197**	214	148			**197**	148	
Activity								
Capital expenditures	**20,027**	15,756	31,127	27%	(36)%	**73,381**	68,472	7%
Gross wells drilled	**2.00**	—	4.00			**7.00**	4.00	
Net wells drilled	**2.00**	—	4.00			**7.00**	4.00	
Financial results								
Sales	**78,778**	66,100	71,926	19%	10%	**268,103**	246,863	9%
Royalties	**(10,599)**	(6,399)	(6,692)	66%	58%	**(28,565)**	(27,091)	5%
Transportation	**(4,475)**	(3,434)	(3,983)	30%	12%	**(14,627)**	(14,758)	(1)%
Operating	**(14,332)**	(13,148)	(11,482)	9%	25%	**(51,002)**	(50,000)	2%
General and administration	**(4,259)**	(2,543)	(5,101)	67%	(17)%	**(13,585)**	(19,101)	(29)%
Other income	**—**	—	3,822	—%	(100)%	**—**	3,822	(100)%
Current income taxes	**(2,348)**	(1,396)	(2,867)	68%	(18)%	**(10,556)**	(2,867)	268%
Fund flows from operations	**42,765**	39,180	45,623	9%	(6)%	**149,768**	136,868	9%
Netbacks ($/boe)								
Sales	**75.13**	63.24	63.71	19%	18%	**67.08**	55.15	22%
Royalties	**(10.11)**	(6.12)	(5.93)	65%	70%	**(7.15)**	(6.05)	18%
Transportation	**(4.27)**	(3.29)	(3.53)	30%	21%	**(3.66)**	(3.30)	11%
Operating	**(13.67)**	(12.58)	(10.17)	9%	34%	**(12.76)**	(11.17)	14%
General and administration	**(4.06)**	(2.43)	(4.52)	67%	(10)%	**(3.40)**	(4.27)	(20)%
Other income	**—**	—	3.39	—%	(100)%	**—**	0.85	(100)%
Current income taxes	**(2.24)**	(1.34)	(2.54)	67%	(12)%	**(2.64)**	(0.64)	313%
Fund flows from operations netback	**40.78**	37.48	40.41	9%	1%	**37.47**	30.57	23%
Realized prices								
Crude oil ($/bbl)	**75.13**	63.24	63.99	19%	17%	**67.08**	55.42	21%
Natural gas ($/mmbtu)	**—**	—	1.55	—%	(100)%	**1.52**	1.59	(4)%
Total ($/boe)	**75.13**	63.24	63.71	19%	18%	**67.08**	55.15	22%
Reference prices								
Dated Brent (US $/bbl)	**61.39**	52.08	49.46	18%	24%	**54.27**	43.69	24%
Dated Brent ($/bbl)	**78.05**	65.22	65.97	20%	18%	**70.44**	57.92	22%

Production
- Q4 2017 production increased 3% versus the prior quarter and was relatively consistent with Q4 2016. Full year production decreased by 7% from 2016 due to production declines, well downtime and third party restrictions impacting Vic Bilh gas production. These decreases more than offset new well production and optimization activities.

Activity review
- During Q4 2017, we drilled two (2.0 net) Neocomian wells as we accelerated a portion of our 2018 drilling program into late 2017. We also continued our workover and optimization programs in the Aquitaine and Paris Basins.
- Our 2017 capital activity included the drilling of six (6.0 net) and completion of four (4.0 net) Neocomian wells and one (1.0 net) horizontal sidetrack well in the Vulaines field as well as the completion of four (4.0 net) Champotran wells that were drilled in Q4 2016.

Sales
- Crude oil in France is priced with reference to Dated Brent.
- Q4 2017 sales per boe increased versus Q3 2017, consistent with stronger Dated Brent pricing. This increase in price was combined with relatively consistent sales volumes, resulting in an increase in sales.
- Sales per boe for the three months and year ended December 31, 2017 increased versus the comparable periods in the prior year, consistent with stronger Dated Brent pricing. In dollar terms, the increase in price was partially offset by lower sales volumes.

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).
- In December 2017, the French government enacted legislation resulting in increased rates for both RCDM and R31 royalties. The change in RCDM royalties was applied retroactively to January 1, 2017 and the change in R31 royalties takes effect January 1, 2018. As a result of these changes, we expect RCDM royalties in 2018 to be approximately €3.65/bbl (compared to approximately €2.90/bbl prior to the newly enacted legislation) and R31 royalties to represent approximately 7.5% of sales (compared to approximately 3.5% in 2017).
- Royalties as a percentage of sales of 13.5% in Q4 2017 increased as compared to 9.7% in Q3 2017 and 9.3% in Q4 2016 due to the aforementioned revision to RCDM royalties. Q4 2017 royalty expense included the entire impact of the retroactive increase in RCDM to the beginning of 2017.
- Royalties as a percentage of sales for the year ended December 31, 2017 of 10.7% were relatively consistent with 11.0% in 2016 as the impact of the higher per unit RCDM royalty rates were offset by higher realized pricing in the current year.

Transportation
- Transportation expense increased in Q4 2017 compared to Q3 2017 and Q4 2016 due to the impact of a prior period adjustment recorded in the current quarter.
- For the year ended December 31, 2017, transportation expense was relatively consistent with the prior year.

Operating
- Operating expense on a per unit and dollar basis increased in Q4 2017 as compared to Q3 2017 due to the timing of maintenance activity and higher electricity costs due to colder weather.
- For the three months and year ended December 31, 2017, operating expense on a per unit basis increased versus the comparable periods in the prior year due to the impact of spreading fixed costs over lower sales volumes. In dollars, the increase in operating expense in Q4 2017 as compared to Q4 2016 is due to a favourable prior period adjustment recorded in the prior year.

General and administration
- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes
- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 34.4%.
- Current income taxes for the year ended December 31, 2017 versus the comparative periods were higher mainly due to higher Dated Brent prices resulting in increased sales.
- On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French corporate income tax rate from 34.43% to 25.825% by 2022, with the first reduction planned for 2019 to 32.02%

NETHERLANDS BUSINESS UNIT

Overview

- Entered the Netherlands in 2004.
- Second largest onshore gas producer (excluding state-owned energy company EBN).
- 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

Netherlands business unit ($M except as indicated)	Three Months Ended			% change		Year Ended		% change
	Dec 31, 2017	Sep 30, 2017	Dec 31, 2016	Q4/17 vs. Q3/17	Q4/17 vs. Q4/16	Dec 31, 2017	Dec 31, 2016	2017 vs. 2016
Production and sales								
Condensate (bbls/d)	**105**	74	57	42%	84%	**90**	88	2%
Natural gas (mmcf/d)	**55.66**	34.90	41.15	59%	35%	**40.54**	47.82	(15)%
Total (boe/d)	**9,381**	5,890	6,915	59%	36%	**6,847**	8,058	(15)%
Activity								
Capital expenditures	**12,300**	11,590	5,737	6%	114%	**31,575**	23,740	33%
Acquisitions	**(38)**	14	28,259			**(24)**	28,259	
Gross wells drilled	**—**	2.00	—			**2.00**	2.00	
Net wells drilled	**—**	1.02	—			**1.02**	0.88	
Financial results								
Sales	**40,914**	21,258	25,978	92%	57%	**108,060**	100,707	7%
Royalties	**(647)**	(360)	(294)	80%	120%	**(1,722)**	(1,462)	18%
Operating	**(6,981)**	(4,498)	(5,660)	55%	23%	**(21,212)**	(20,796)	2%
General and administration	**(546)**	(510)	(162)	7%	237%	**(2,212)**	(1,525)	45%
Current income taxes	**6,975**	(1,983)	100	N/A	6,875%	**3,331**	(6,624)	N/A
Fund flows from operations	**39,715**	13,907	19,962	186%	99%	**86,245**	70,300	23%
Netbacks ($/boe)								
Sales	**47.41**	39.23	40.84	21%	16%	**43.24**	34.15	27%
Royalties	**(0.75)**	(0.66)	(0.46)	14%	63%	**(0.69)**	(0.50)	38%
Operating	**(8.09)**	(8.30)	(8.90)	(3)%	(9)%	**(8.49)**	(7.05)	20%
General and administration	**(0.63)**	(0.94)	(0.26)	(33)%	142%	**(0.89)**	(0.52)	71%
Current income taxes	**8.08**	(3.66)	0.16	N/A	4,950%	**1.33**	(2.25)	N/A
Fund flows from operations netback	**46.02**	25.67	31.38	79%	47%	**34.50**	23.83	45%
Realized prices								
Condensate ($/bbl)	**66.38**	52.10	63.18	27%	5%	**56.90**	44.93	27%
Natural gas ($/mmbtu)	**7.87**	6.51	6.78	21%	16%	**7.18**	5.67	27%
Total ($/boe)	**47.41**	39.23	40.84	21%	16%	**43.24**	34.15	27%
Reference prices								
TTF ($/mmbtu)	**8.36**	6.93	7.21	21%	16%	**7.43**	6.00	24%
TTF (€/mmbtu)	**5.58**	4.71	5.01	18%	11%	**5.07**	4.09	24%

Production

- Q4 2017 production increased 59% quarter-over-quarter and 36% year-over-year following the receipt of permits to increase production on two key pools, and also due to the impact of a major turnaround at the Garjip processing facility that occurred during Q2 2017. Year-over-year production decreased 15% due to the restriction of production related to permitting delays earlier in 2017.

Activity review
- In Q4 2017, we completed a 315 square kilometre 3D seismic survey in the Akkrum exploration licence and the South Friesland III production licence.
- The test rate from the Eesveen-2 well (60% working interest) drilled in the prior quarter was limited to approximately 10 mmcf/d net during the test period.

Sales
- The price of our natural gas in the Netherlands is based on the TTF index.
- Q4 2017 sales per boe increased versus Q3 2017, consistent with an increase in the TTF reference price.
- Sales per boe for the three months and year ended December 31, 2017 increased versus the comparable periods in the prior year, consistent with increases in the TTF reference price.

Royalties
- In the Netherlands, certain wells are subject to overriding royalties or royalties that take effect only when specified production levels are exceeded. As such, fluctuations in royalty expense in the periods presented primarily relates to the amount of production from those wells subject to overriding and production royalties.

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

Operating
- Q4 2017 per unit operating expense decreased slightly versus Q3 2017 and Q4 2016 due to the impact of higher volumes.
- Operating expense on a per unit basis increased compared to 2016 due to the impact of fixed expenditures on lower production volumes.

General and administration
- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

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 asset retirement obligations, at a tax rate of 50%.
- Current income taxes in Q4 2017 and for the year ended December 31, 2017 versus the comparative periods were lower mainly due to an increased tax deduction for future asset retirement obligations resulting from a reduction in applicable discount rate assumptions.

GERMANY BUSINESS UNIT

Overview

- Entered Germany in February 2014.
- Successfully integrated the December 2016 acquisition of operated and non-operated interests in five oil and three gas producing fields from Engie E&P Deutschland GmbH ("Engie Acquisition"). Vermilion has assumed operatorship of six of the eight producing fields, representing our first operated producing properties in Germany.
- Hold a 25% interest in a four partner consortium at Dummersee-Uchte. 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 a 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 Ossenbeck and Weesen licenses (110,000 net acres) in 2015 and Aller license (50,000 net acres) in March 2017 surrounding the operated oil fields acquired in December 2016.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Germany business unit ($M except as indicated)	**Dec 31, 2017**	**Sep 30, 2017**	**Dec 31, 2016**	**Q4/17 vs. Q3/17**	**Q4/17 vs. Q4/16**	**Dec 31, 2017**	**Dec 31, 2016**	**2017 vs. 2016**
Production and sales								
Crude oil (bbls/d)	**1,148**	1,054	—	9%	100%	**1,060**	—	100%
Natural gas (mmcf/d)	**18.19**	20.12	14.80	(10)%	23%	**19.39**	14.90	30%
Total (boe/d)	**4,180**	4,407	2,467	(5)%	69%	**4,291**	2,483	73%
Production mix (% of total)								
Crude oil	**27%**	24%	—%			**25%**	—%	
Natural gas	**73%**	76%	100%			**75%**	100%	
Activity								
Capital expenditures	**5,279**	3,020	1,694	75%	212%	**9,531**	3,803	151%
Acquisitions	**—**	—	48,377			**—**	48,377	
Financial results								
Sales	**18,898**	15,663	8,294	21%	128%	**68,696**	29,049	136%
Royalties	**(1,798)**	(2,261)	(12)	(20)%	14,883%	**(6,655)**	(2,089)	219%
Transportation	**(1,164)**	(1,603)	(375)	(27)%	210%	**(6,207)**	(2,869)	116%
Operating	**(6,025)**	(3,477)	(3,959)	73%	52%	**(20,176)**	(12,379)	63%
General and administration	**(2,080)**	(1,708)	(1,755)	22%	19%	**(7,767)**	(8,314)	(7)%
Fund flows from operations	**7,831**	6,614	2,193	18%	257%	**27,891**	3,398	721%
Netbacks ($/boe)								
Sales	**50.22**	38.52	36.54	30%	37%	**44.37**	31.97	39%
Royalties	**(4.78)**	(5.56)	(0.06)	(14)%	7,867%	**(4.30)**	(2.30)	87%
Transportation	**(3.09)**	(3.94)	(1.65)	(22)%	87%	**(4.01)**	(3.16)	27%
Operating	**(16.01)**	(8.55)	(17.44)	87%	(8)%	**(13.03)**	(13.62)	(4)%
General and administration	**(5.53)**	(4.20)	(7.73)	32%	(28)%	**(5.02)**	(9.15)	(45)%
Fund flows from operations netback	**20.81**	16.27	9.66	28%	115%	**18.01**	3.74	382%
Realized prices								
Crude oil ($/bbl)	**72.58**	55.95	—	30%	100%	**63.91**	—	100%
Natural gas ($/mmbtu)	**7.07**	5.50	6.09	29%	16%	**6.38**	5.33	20%
Total ($/boe)	**50.22**	38.52	36.54	30%	37%	**44.37**	31.97	39%
Reference prices								
Dated Brent (US $/bbl)	**61.39**	52.08	49.46	18%	24%	**54.27**	43.69	24%
Dated Brent ($/bbl)	**78.05**	65.22	65.97	20%	18%	**70.44**	57.92	22%
TTF ($/mmbtu)	**8.36**	6.93	7.21	21%	16%	**7.43**	6.00	24%
TTF (€/mmbtu)	**5.58**	4.71	5.01	18%	11%	**5.07**	4.09	24%

Production
- Q4 2017 production decreased from the prior quarter due to longer than anticipated downtime on one of our wells in December following a SCADA installation. Fourth quarter and full year 2017 production increased 69% and 73% year-over-year, respectively, due to production additions from the Engie Acquisition that closed December 2016.

Activity review
- 2017 activity focused on workover and optimization opportunities on the assets included in the Engie Acquisition.
- In 2018, we plan to continue permitting and pre-drill activities associated with our first operated well in Germany, Burgmoor Z5 (25% working interest) in the Dümmersee-Uchte area, which we expect to drill in 2019.

Sales
- The price of our natural gas in Germany is based on the TTF index. Crude oil in Germany is priced with reference to Dated Brent.
- Sales per boe increased versus all comparable periods due to the timing of sales and increases in both crude oil and natural gas benchmark prices.

Royalties
- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Royalties as a percentage of sales of 9.5% in Q4 2017 were lower than 14.4% in Q3 2017 due to the impact of an adjustment recorded in the prior quarter.
- For the three months ended December 31, 2017, royalties as a percentage of sales of 9.5% increased from a negligible amount in Q4 2016 due to the impact of favourable prior period adjustments recorded in Q4 2016. For the year ended December 31, 2017, royalties as a percentage of sales of 9.7% was higher than 7.2% in the prior year due the impact of the prior period adjustment recorded in 2016.

Transportation
- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer and deliver crude oil to the refinery.
- Q4 2017 per unit transportation expense was relatively consistent with Q3 2017.
- For the three months and year ended December 31, 2017, transportation expense increased on a per unit and dollar basis relative to the comparable periods in the prior year due to the impact of the aforementioned acquisition.

Operating
- Operating expense increased in Q4 2017 versus Q3 2017 due to the impact of a favourable prior period adjustment recorded in the prior quarter.
- For the three months and year ended December 31, 2017, operating expense on a per unit basis decreased slightly versus the comparable periods in 2016 due to the impact of higher volumes.

General and administration
- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.
- On a per unit basis, general and administration costs have improved compared to 2016 as a result of our growing production base in Germany.

Current income taxes
- As a result of our tax pools in Germany, we do not expect to incur current income taxes in the German Business Unit in for the foreseeable future.

IRELAND BUSINESS UNIT

Overview

- Entered Ireland in 2009.
- Initial investment was an 18.5% non-operating interest in the offshore Corrib gas field located approximately 83 km off the northwest coast of Ireland.
- On July 12, 2017, Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership that is expected to result in Vermilion increasing ownership in Corrib to 20% and taking over operatorship upon close of the acquisition which is expected to occur in the first half of 2018.
- The Corrib gas development comprises six offshore wells, offshore and onshore sales and transportation pipeline segments as well as a natural gas processing facility.
- 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.

Operational and financial review

	Three Months Ended			% change		Year Ended		% change
Ireland business unit ($M except as indicated)	**Dec 31, 2017**	**Sep 30, 2017**	**Dec 31, 2016**	**Q4/17 vs. Q3/17**	**Q4/17 vs. Q4/16**	**Dec 31, 2017**	**Dec 31, 2016**	**2017 vs. 2016**
Production and sales								
Natural gas (mmcf/d)	**56.23**	49.04	62.92	15%	(11)%	**58.43**	50.89	15%
Total (boe/d)	**9,372**	8,173	10,486	15%	(11)%	**9,737**	8,482	15%
Activity								
Capital expenditures	**327**	1,101	1,711	(70)%	(81)%	**551**	9,375	(94)%
Financial results								
Sales	**43,793**	28,218	42,727	55%	2%	**153,330**	109,156	40%
Transportation	**(1,496)**	(1,252)	(1,703)	19%	(12)%	**(5,205)**	(6,492)	(20)%
Operating	**(2,977)**	(5,717)	(5,148)	(48)%	(42)%	**(17,596)**	(18,646)	(6)%
General and administration	**(517)**	(670)	(1,523)	(23)%	(66)%	**(2,320)**	(4,772)	(51)%
Fund flows from operations	**38,803**	20,579	34,353	89%	13%	**128,209**	79,246	62%
Netbacks ($/boe)								
Sales	**50.79**	37.53	44.29	35%	15%	**43.14**	35.16	23%
Transportation	**(1.74)**	(1.66)	(1.77)	5%	(2)%	**(1.46)**	(2.09)	(30)%
Operating	**(3.45)**	(7.60)	(5.34)	(55)%	(35)%	**(4.95)**	(6.01)	(18)%
General and administration	**(0.60)**	(0.89)	(1.58)	(33)%	(62)%	**(0.65)**	(1.54)	(58)%
Fund flows from operations netback	**45.00**	27.38	35.60	64%	26%	**36.08**	25.52	41%
Reference prices								
NBP ($/mmbtu)	**8.70**	6.78	7.51	28%	16%	**7.49**	6.15	22%
NBP (€/mmbtu)	**5.81**	4.61	5.22	26%	11%	**5.12**	4.19	22%

Production

- Q4 2017 production increased by 15% quarter-over-quarter and decreased by 11% year-over-year. This was due to an extended downtime period following a plant turnaround, which started during Q3 2017 and ended early Q4 2017.

Activity review

- On July 12, 2017 Vermilion and CPPIB announced a strategic partnership in Corrib, whereby CPPIB will acquire Shell E&P Ireland Limited's 45% interest in Corrib for total cash consideration of €830 million, subject to customary closing adjustments and future contingent value payments based on performance and realized pricing. At closing, Vermilion expects to assume operatorship of Corrib. In addition to operatorship, CPPIB plans to transfer a 1.5% working interest to Vermilion for €19.4 million ($28.4 million), before closing adjustments. Vermilion's incremental 1.5% ownership of Corrib would represent approximately 850 boe/d (100% gas) based on current production expectations for Corrib. The acquisition has an effective date of January 1, 2017 and is anticipated to close in the first half of 2018.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Q4 2017 sales per boe increased versus Q3 2017, consistent with an increase in the NBP reference price.
- For the three months and year ended December 31, 2017, sales per boe increased relatively to the comparable periods in the prior year, consistent with increases 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 2017 transportation expense was consistent with Q3 2017.
- Transportation expense for the three months and year ended December 31, 2017 decreased relative to the comparable periods in the prior year due to a decrease in the current year ship-or-pay obligation.

Operating
- Operating expense on a per unit and dollar basis decreased versus all comparable periods due to the timing of maintenance work.

General and administration
- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes
- Given the significant level of investment in Corrib and the resulting tax pools, we do not expect to incur current income taxes in the Ireland Business Unit for the foreseeable future.

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 ($M except as indicated)	**Dec 31, 2017**	**Sep 30, 2017**	**Dec 31, 2016**	**Q4/17 vs. Q3/17**	**Q4/17 vs. Q4/16**	**Dec 31, 2017**	**Dec 31, 2016**	**2017 vs. 2016**
Production								
Crude oil (bbls/d)	**4,993**	5,473	6,388	(9)%	(22)%	**5,770**	6,304	(8)%
Sales								
Crude oil (bbls/d)	**4,707**	5,722	6,038	(18)%	(22)%	**5,717**	6,197	(8)%
Inventory (mbbls)								
Opening crude oil inventory	**108**	131	82			**115**	75	
Crude oil production	**459**	503	588			**2,106**	2,307	
Crude oil sales	**(433)**	(526)	(555)			**(2,087)**	(2,267)	
Closing crude oil inventory	**134**	108	115			**134**	115	
Activity								
Capital expenditures	**7,192**	10,154	5,236	(29)%	37%	**29,942**	59,910	(50)%
Gross wells drilled	**—**	—	—			**—**	2.00	
Net wells drilled	**—**	—	—			**—**	2.00	
Financial results								
Sales	**36,086**	35,257	38,352	2%	(6)%	**154,391**	136,835	13%
Operating	**(12,172)**	(12,292)	(14,905)	(1)%	(18)%	**(50,139)**	(47,507)	6%
General and administration	**(3,193)**	(1,675)	(1,998)	91%	60%	**(8,194)**	(6,400)	28%
Current income taxes	**(5,327)**	(4,538)	(4,271)	17%	25%	**(24,355)**	(9,090)	168%
Fund flows from operations	**15,394**	16,752	17,178	(8)%	(10)%	**71,703**	73,838	(3)%
Netbacks ($/boe)								
Sales	**83.32**	66.97	69.05	24%	21%	**73.99**	60.33	23%
Operating	**(28.11)**	(23.35)	(26.83)	20%	5%	**(24.03)**	(20.95)	15%
General and administration	**(7.37)**	(3.18)	(3.60)	132%	105%	**(3.93)**	(2.82)	39%
PRRT	**(8.25)**	(8.25)	(2.82)	—%	193%	**(9.50)**	(0.69)	1,277%
Corporate income taxes	**(4.05)**	(0.37)	(4.87)	995%	(17)%	**(2.17)**	(3.32)	(35)%
Fund flows from operations netback	**35.54**	31.82	30.93	12%	15%	**34.36**	32.55	6%
Reference prices								
Dated Brent (US $/bbl)	**61.39**	52.08	49.46	18%	24%	**54.27**	43.69	24%
Dated Brent ($/bbl)	**78.05**	65.22	65.97	20%	18%	**70.44**	57.92	22%

Production

- Q4 2017 production decreased 9% quarter-over-quarter and 22% year-over-year, primarily due to planned maintenance during the quarter, which resulted in eight days of downtime. Full year 2017 production decreased 8% versus 2016.
- 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 annual production levels of approximately 6,000 bbls/d.

Activity review

- 2017 efforts were largely focused on facility enhancements, including work relating to platform life extension, and debottlenecking fluid handling capabilities on Wandoo B.
- Following our successful 2015 and 2016 drilling campaigns, we do not expect to drill any additional wells in Australia until 2019.
- 2018 activity will be focused on adding value through asset optimization and targeted proactive maintenance, in addition to preparing for our 2019 planned drilling campaign.

Sales
- Crude oil in Australia is priced with reference to Dated Brent.
- Q4 2017 sales per boe increased versus Q3 2017 and Q4 2016, consistent with an increase in the Dated Brent reference price. This increase in price was offset by lower sales volumes in the current quarter versus the comparable quarters, resulting in relatively consistent sales.
- Sales per boe for the year ended December 31, 2017 increased versus the prior year, consistent with an increase in the Dated Brent reference price. This increase in price was partially offset by lower sales volumes in the current year.

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 per unit basis increased in Q4 2017 versus Q3 2017 due to lower sales volumes. On a dollar basis, operating expense was relatively consistent.
- For the three months and year ended December 31, 2017, operating expense on a per unit basis increased versus the comparable periods in the prior year due to lower sales volumes in the current periods. On a dollar basis, fluctuations in operating expense versus the comparable periods were due to the timing of maintenance work.

General and administration
- Fluctuations in general and administration expense for all comparable periods are primarily due to the timing of expenditures and allocations from our corporate segment. The increase in Q4 2017 over the prior quarter and prior year was primarily due to additional costs associated with the evaluation of a discontinued acquisition opportunity.

Current 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 2017 and for the year ended December 31, 2017 versus the comparative periods were higher mainly due to increased pre-tax fund flows from operations.

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 ($M except as indicated)	**Dec 31, 2017**	**Sep 30, 2017**	**Dec 31, 2016**	**Q4/17 vs. Q3/17**	**Q4/17 vs. Q4/16**	**Dec 31, 2017**	**Dec 31, 2016**	**2017 vs. 2016**
Production and sales								
Crude oil (bbls/d)	**667**	880	362	(24)%	84%	**666**	393	69%
NGLs (bbls/d)	**43**	56	23	(23)%	87%	**50**	29	72%
Natural gas (mmcf/d)	**0.29**	0.64	0.18	(55)%	61%	**0.39**	0.21	86%
Total (boe/d)	**758**	1,043	414	(27)%	83%	**781**	457	71%
Activity								
Capital expenditures	**1,018**	1,362	4,037	(25)%	(75)%	**19,074**	13,539	41%
Acquisitions	**91**	1,250	377			**3,403**	5,935	
Gross wells drilled	**—**	—	1.00			**3.00**	1.00	
Net wells drilled	**—**	—	1.00			**3.00**	1.00	
Financial results								
Sales	**4,350**	4,771	2,041	(9)%	113%	**15,355**	7,314	110%
Royalties	**(1,196)**	(1,321)	(611)	(9)%	96%	**(4,276)**	(2,167)	97%
Transportation	**(15)**	(26)	—	(42)%	100%	**(41)**	—	100%
Operating	**(397)**	(629)	(301)	(37)%	32%	**(1,698)**	(1,314)	29%
General and administration	**(1,274)**	(935)	(877)	36%	45%	**(4,341)**	(3,624)	20%
Fund flows from operations	**1,468**	1,860	252	(21)%	483%	**4,999**	209	2,292%
Netbacks ($/boe)								
Sales	**62.40**	49.72	53.58	26%	16%	**53.84**	43.70	23%
Royalties	**(17.16)**	(13.77)	(16.05)	25%	7%	**(14.99)**	(12.95)	16%
Transportation	**(0.21)**	(0.27)	—	(22)%	100%	**(0.14)**	—	100%
Operating	**(5.70)**	(6.56)	(7.91)	(13)%	(28)%	**(5.95)**	(7.85)	(24)%
General and administration	**(18.28)**	(9.74)	(23.02)	88%	(21)%	**(15.22)**	(21.65)	(30)%
Fund flows from operations netback	**21.05**	19.38	6.60	9%	219%	**17.54**	1.25	1,303%
Realized prices								
Crude oil ($/bbl)	**67.15**	55.74	59.09	20%	14%	**60.07**	49.86	20%
NGLs ($/bbl)	**41.25**	26.35	19.48	57%	112%	**25.11**	7.38	240%
Natural gas ($/mmbtu)	**2.48**	2.07	1.93	20%	28%	**2.05**	0.85	141%
Total ($/boe)	**62.40**	49.72	53.58	26%	16%	**53.84**	43.70	23%
Reference prices								
WTI (US $/bbl)	**55.40**	48.20	49.29	15%	12%	**50.95**	43.32	18%
WTI ($/bbl)	**70.43**	60.37	65.75	17%	7%	**66.13**	57.42	15%
Henry Hub (US $/mmbtu)	**2.93**	3.00	2.98	(2)%	(2)%	**3.11**	2.46	26%
Henry Hub ($/mmbtu)	**3.73**	3.76	3.98	(1)%	(6)%	**4.04**	3.27	24%

Production

- Q4 2017 production decreased 27% from the prior quarter as a result of depleted flush production from the three (3.0 net) wells placed on production during Q2 2017 and due to a force majeure event at a third-party gas plant. Fourth quarter production increased 83% year-over-year as a result of the 2017 drilling program.
- Full year 2017 production increased 71% from 2016 as a result of our 2017 drilling program.

Activity

- 2017 activity was focused on drilling three (3.0 net) horizontal wells targeting the light oil bearing Turner Sand in the Powder River Basin. The wells were completed late in the first quarter and into the second quarter with fracs ranging from 31 to 40 stages per well.

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 2017 sales per boe increased versus Q3 2017, consistent with an increase in the WTI reference price.
- For the three months and year ended December 31, 2017, sales per boe increased relative to the comparable periods in the prior year, consistent with stronger crude oil pricing.

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 28%, and remained relatively consistent in Q4 2017 as compared to Q3 2017.
- For the three months and year ended December 31, 2017, royalties as a percentage of sales decreased to approximately 28% from approximately 30% in the comparable periods in the prior year. This decrease is a result of our purchase of overriding royalty interests (ranging from 0.83% to 5.00%) for US$1.5 million, effective January 1, 2017. On a go-forward basis, we expect royalties as a percentage of sales to remain at approximately 28%.

Transportation
- Transportation expense in the United States relates to the delivery of crude oil and condensate production to major pipelines where legal title transfers.
- Fluctuations in transportation expense for all periods presented relate to fluctuations in production subject to trucking costs.

Operating
- Operating expense on a per unit and dollar basis decreased in Q4 2017 as compared to Q3 2017 due to the timing of maintenance work.
- For the three months and year ended December 31, 2017, operating expense on a per unit basis decreased versus the comparable periods in the prior year due to the impact of higher volumes. In dollars, the increase in operating expense in both periods was attributable to higher production.

General and administration
- Fluctuations in general and administration expense for all comparable periods were due to the timing of expenditures and allocations from our corporate segment.

Current income taxes
- As a result of our tax pools in the United States, we do not expect to incur current income taxes in the US Business Unit for the foreseeable future.

CORPORATE

Overview

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

Financial review

CORPORATE ($M)	Three Months Ended			Year Ended	
	Dec 31, 2017	Sep 30, 2017	Dec 31, 2016	Dec 31, 2017	Dec 31, 2016
Activity					
Capital expenditures	**1,295**	4,653	445	**7,728**	863
Acquisitions	**2,207**	—	322	**2,247**	2,644
Financial results					
General and administration (expense) recovery	**(1,532)**	(1,834)	1,987	**(6,350)**	2,733
Current income taxes	**(542)**	480	(370)	**(527)**	(1,097)
Interest expense	**(13,710)**	(13,400)	(14,410)	**(57,313)**	(56,957)
Realized (loss) gain on derivatives	**(7,493)**	8,723	1,920	**4,721**	65,376
Realized foreign exchange gain (loss)	**2,899**	(4,110)	1,291	**2,316**	4,041
Realized other income	**166**	214	120	**674**	205
Fund flows from operations	**(20,212)**	(9,927)	(9,462)	**(56,479)**	14,301

General and administration

- Fluctuations in general and administration costs for the three months and year ended December 31, 2017 versus all comparable periods were due to allocations to the various business unit segments.

Current income taxes

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

Interest expense

- The decrease in interest expense for the three months ended December 31, 2017 versus the comparable period in the prior year was due to lower drawings on the revolving credit facility.
- The increase in interest expense for the year ended December 31, 2017 versus the prior year was due to the issuance of the senior unsecured notes in Q1 2017, which bear interest at a higher fixed rate compared to the variable rates under the revolving credit facility. The impact of the higher fixed rates was partially offset by lower drawings on the revolving credit facility and lower standby fees from a voluntary reduction of the available credit on the revolving credit facility from $2.0 billion to $1.4 billion.

Realized gain or loss on derivatives

- The realized gain on derivatives for the year ended December 31, 2017 related primarily to amounts received on European natural gas hedges.
- A listing of derivative positions as at December 31, 2017 is included in “Supplemental Table 2” of this MD&A.

FINANCIAL PERFORMANCE REVIEW

	Year Ended		
($M except per share)	**Dec 31, 2017**	**Dec 31, 2016**	**Dec 31, 2015**
Total assets	**3,974,965**	4,087,184	4,209,220
Long-term debt	**1,270,330**	1,362,192	1,162,998
Petroleum and natural gas sales	**1,098,838**	882,791	939,586
Net earnings (loss)	**62,258**	(160,051)	(217,302)
Net earnings (loss) per share			
Basic	**0.52**	(1.38)	(1.98)
Diluted	**0.51**	(1.38)	(1.98)
Cash dividends ($/share)	**2.58**	2.58	2.58

	Three Months Ended							
($M except per share)	**Dec 31, 2017**	**Sep 30, 2017**	**Jun 30, 2017**	**Mar 31, 2017**	**Dec 31, 2016**	**Sep 30, 2016**	**Jun 30, 2016**	**Mar 31, 2016**
Petroleum and natural gas sales	**317,341**	248,505	271,391	261,601	259,891	232,660	212,855	177,385
Net (loss) earnings	**8,645**	(39,191)	48,264	44,540	(4,032)	(14,475)	(55,696)	(85,848)
Net (loss) earnings per share								
Basic	**0.07**	(0.32)	0.40	0.38	(0.03)	(0.12)	(0.48)	(0.76)
Diluted	**0.07**	(0.32)	0.39	0.37	(0.03)	(0.12)	(0.48)	(0.76)

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

	Three Months Ended			Year Ended	
	Dec 31, 2017	**Sep 30, 2017**	**Dec 31, 2016**	**Dec 31, 2017**	**Dec 31, 2016**
Fund flows from operations	**181,253**	130,755	149,582	**602,565**	510,791
Equity based compensation	**(16,087)**	(12,858)	(19,489)	**(61,579)**	(69,235)
Unrealized loss on derivative instruments	**(80,012)**	(24,198)	(74,943)	**(1,062)**	(137,993)
Unrealized foreign exchange gain (loss)	**40,660**	(3,016)	(2,457)	**71,742**	(792)
Unrealized other expense	**(197)**	(200)	—	**(637)**	(131)
Accretion	**(6,991)**	(6,850)	(6,308)	**(26,971)**	(24,783)
Depletion and depreciation	**(129,179)**	(120,826)	(126,855)	**(491,683)**	(528,002)
Deferred tax	**19,198**	(1,998)	54,437	**(30,117)**	82,855
Gain on acquisition	**—**	—	22,001	**—**	22,001
Impairments	**—**	—	—	**—**	(14,762)
Net earnings (loss)	**8,645**	(39,191)	(4,032)	**62,258**	(160,051)

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 gains 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 expense increased in Q4 2017 compared to Q3 2017 due to a revision of performance estimates. For the three months and year ended December 31, 2017, equity based compensation decreased versus the comparable periods in 2016 due to a reduction in the value of awards outstanding under the VIP.

Unrealized gain or loss on derivative instruments
Unrealized gain or loss on derivative instruments arise as a result of changes in future commodity price forecasts. 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 future commodity price forecasts decline and vice-versa.

For the three months ended December 31, 2017, we recognized an unrealized loss on derivative instruments of $80.0 million. This loss primarily related to crude oil and European natural gas derivative instruments for 2018 and 2019, partially offset by unrealized gains on our North American natural gas derivative instruments for 2018.

For the year ended December 31, 2017, we recognized an unrealized loss on derivative instruments of $1.1 million. This unrealized loss largely related to crude oil derivative instruments for 2018, as well as the aforementioned offsetting cross-currency interest rate swap entered into in Q4 2017. This loss was almost entirely offset by the reversal of the net derivative liability position of $69.7 million on our balance sheet as at December 31, 2016, as well as unrealized gains on North American natural gas derivative instruments for 2018.

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. These monetary assets primarily relate to Euro denominated intercompany loans from Vermilion Energy Inc. to our international subsidiaries. These monetary liabilities primarily relate to our US$300.0 million senior unsecured notes.

Unrealized foreign exchange gains and losses result from translating these monetary assets and liabilities from their underlying currency to the Canadian dollar. Unrealized foreign exchange primarily results from the translation of Euro denominated intercompany loans and US dollar denominated long-term debt. 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, 2017, the impact of the Canadian dollar weakening against the Euro was more significant than the impact of the Canadian dollar weakening against the US dollar, resulting in an unrealized foreign exchange gain. For the year ended December 31, 2017, the Canadian dollar weakened against the Euro and strengthened against the US dollar, resulting in an unrealized foreign exchange gain.

As at December 31, 2017, a $0.01 appreciation of the Euro against the Canadian dollar would result in a $4.6 million increase to net earnings. In contrast, a $0.01 appreciation of the US dollar against the Canadian dollar would result in a $2.2 million decrease to net earnings.

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 cost of capital assets over the useful life of the respective assets. Depletion and depreciation expense per unit of production is determined for each depletion unit (which are groups of assets within a specific production area that have similar economic lives) by dividing the sum of the net book value of capital assets and future development costs by total proved plus probable reserves.

Fluctuations in depletion and depreciation expense are primarily the result of changes in produced crude oil and natural gas volumes and changes in depletion and depreciation per unit. Fluctuations in depletion and depreciation per unit are the result of changes in reserves, future development costs, and relative production mix.

Depletion and depreciation on a per boe basis for Q4 2017 of $19.33 was consistent with $19.28 in Q3 2017. For the three months and year ended December 31, 2017, depletion and depreciation on a per boe basis of $19.33 and $19.87 were lower than $22.42 and $22.65 in the respective comparable periods in 2016 due to reduced depletion and depreciation rates as a result of increased reserves and lower estimated future development costs.

Deferred tax
On our balance sheet, deferred tax assets arise when the tax basis of an asset exceeds its accounting basis (known as a deductible temporary difference). Conversely, deferred tax liabilities arise when the tax basis of an asset is less than its accounting basis (known as a taxable temporary difference). Deferred tax assets are recognized only to the extent that it is probable that there are future taxable profits against which the deductible temporary difference can be utilized. Deferred tax assets and liabilities are measured at the enacted or substantively enacted tax rate that is expected to apply when the asset is realized or the liability is settled.

As such, fluctuations in deferred tax expenses and recoveries primarily arise as a result of: changes in the accounting basis of an asset or liability without a corresponding tax basis change (e.g. when derivative assets and liabilities are marked-to-market or when accounting depletion differs from tax depletion), changes in available tax losses (e.g. if they are utilized to offset taxable income), changes in estimated future taxable profits resulting in a de-recognition or re-recognition of deferred tax assets, and changes in enacted or substantively enacted tax rates.

In Q4 2017, a $19.2 million deferred tax recovery primarily resulted from the impact of the adoption by the French Parliament of the Finance Law for 2018. The Finance Law for 2018 included progressive reductions of the corporate tax rate from 34.43% to 25.825% by 2022 and thus reduced the effective tax rate applied against Vermilion's taxable temporary differences in France. For the year ended December 31, 2017, the deferred tax expense of $30.1 million related to the de-recognition of a portion of non-expiring tax loss pools in Ireland as there is uncertainty as to the Company's ability to fully utilize such losses based on forecasted commodity prices in effect as at December 31, 2017, partially offset by the aforementioned change in effective tax rates in France.

TAXES

Current income tax rates
Vermilion pays corporate income taxes in France, the Netherlands, and Australia. In addition, Vermilion pays Petroleum Resource Rent Tax ("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.

For 2017 and 2016, taxable income was subject to corporate income tax at the following rates:

Jurisdiction	2017	2016
Canada	27.0%	27.0%
France	34.4%	34.4%
Netherlands (1)	50.0%	50.0%
Germany	26.3%	24.2%
Ireland	25.0%	25.0%
Australia	30.0%	30.0%
United States	35.0%	35.0%

(1) In the Netherlands, an additional 10% uplift deduction is allowed against taxable income that is applied to operating expenses, eligible general and administration expenses and tax deductions for depletion and abandonment retirement obligations.

Tax legislation changes
On December 22, 2017, the Tax Cuts and Jobs Act was signed into law in the United States. The Tax Cuts and Jobs Act reduces the U.S. federal corporate income tax rate to 21%.

On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French corporate income tax rate from 34.43% to 25.825% by 2022, with the first reduction planned for 2019 to 32.02%.

Tax pools
As at December 31, 2017, we had the following tax pools:

($M)	Oil & Gas Assets		Tax Losses		Other	Total
Canada	914,071	(1)	517,687	(4)	20,113	1,451,871
France	332,435	(2)	10,688	(5)	—	343,123
Netherlands	78,417	(3)	7,078	(4)	—	85,495
Germany	184,549	(3)	88,712	(6)	18,878	292,139
Ireland	—		1,327,743	(4)	—	1,327,743
Australia	266,208	(1)	—		—	266,208
United States	37,022	(1)	43,305	(4)	1,783	82,110
Total	1,812,702		1,995,213		40,774	3,848,689

(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) Tax losses can be carried forward at 100% against taxable income
(5) 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
(6) 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

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. As at December 31, 2017 our ratio of net debt to trailing fund flows from operations was 2.3 (2016 - 2.8) and was 1.9 based on annualized Q4 2017 fund flows from operations.

We remain focused on maintaining and strengthening our balance sheet by aligning our exploration and development capital budget with forecasted fund flows from operations to target a payout ratio (a non-GAAP financial measure) of at or less than 100%. We continually monitor for changes in forecasted fund flows from operations as a result of changes to forward commodity prices and as appropriate we will make adjustments to our exploration and development capital plans. As a result of our focus on this payout ratio target, we intend for the ratio of net debt to fund flows from operations to trend towards 1.5 over time.

Net debt

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

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Long-term debt	**1,270,330**	1,362,192
Current liabilities	**363,306**	290,862
Current assets	**(261,846)**	(225,906)
Net debt	**1,371,790**	1,427,148
Ratio of net debt to fund flows from operations	**2.3**	2.8
Ratio of net debt to fourth quarter annualized fund flows from operations	**1.9**	2.4

As at December 31, 2017, long term debt decreased to $1.27 billion (December 31, 2016 - $1.36 billion) as fund flows from operations generated in excess of expenditures was used to reduce debt. This decrease in long-term debt decreased net debt from $1.43 billion at December 31, 2016 to $1.37 billion at December 31, 2017. Stronger commodity prices and higher production versus the prior period increased fund flows from operations, resulting in the ratio of net debt to fund flows from operations decreasing from 2.8 to 2.3.

Long term debt

The balances recognized on our balance sheet are as follows:

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Revolving credit facility	**899,595**	1,362,192
Senior unsecured notes	**370,735**	—
Long-term debt	**1,270,330**	1,362,192

Revolving Credit Facility

As at December 31, 2017, Vermilion had in place a bank revolving credit facility maturing May 31, 2021 with the following outstanding positions:

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Total facility amount	**1,400,000**	2,000,000
Amount drawn	**(899,595)**	(1,362,192)
Letters of credit outstanding	**(7,400)**	(20,100)
Unutilized capacity	**493,005**	617,708

In April of 2017, we negotiated an extension of our revolving credit facility with our syndicate of lenders from May 31, 2019 to May 31, 2021. Further, as a result of projected liquidity requirements and the proceeds from our senior unsecured notes issuance, we elected to reduce the total facility amount from $2.0 billion to $1.4 billion.

As at December 31, 2017, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	**Limit**	**Dec 31, 2017**	**Dec 31, 2016**
Consolidated total debt to consolidated EBITDA	4.0	**1.87**	2.36
Consolidated total senior debt to consolidated EBITDA	3.5	**1.3**	2.32
Consolidated total senior debt to total capitalization	55%	**32%**	46%

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", 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.

Senior Unsecured Notes

On March 13, 2017, Vermilion issued US$300 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, paid semi-annually on March 15 and September 15, and mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally in right of payment with existing and future senior indebtedness of the Company.

The senior unsecured notes were recognized at amortized cost and include the transaction costs directly related to the issuance.

Vermilion may, at its option, redeem the senior unsecured notes prior to maturity as follows:

- Prior to March 15, 2020, Vermilion may redeem up to 35% of the original principal amount of the senior unsecured notes with the proceeds of certain equity offerings by the Company at a redemption price of 105.625% of the principal amount, plus any accrued and unpaid interest to but excluding the applicable redemption date.
- Prior to March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at a price equal to 100% of the principal amount of the senior unsecured notes, plus a "make-whole" premium and any accrued and unpaid interest.
- On or after March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table, plus any accrued and unpaid interest.

Year	**Redemption price**
2020	104.219%
2021	102.813%
2022	101.406%
2023 and thereafter	100.000%

Shareholders' capital

During the year ended December 31, 2017 we maintained monthly dividends at $0.215 per share. In total, dividends declared in 2017 were $311.4 million.

The following table outlines our dividend payment history:

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

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

Although we expect to be able to maintain our current dividend, fund flows from operations may not be sufficient 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, 2016	118,263	2,452,722
Shares issued for the Dividend Reinvestment Plan	2,429	110,493
Vesting of equity based awards	1,060	69,743
Equity based compensation	197	9,270
Share-settled dividends on vested equity based awards	170	8,478
Balance as at December 31, 2017	122,119	2,650,706

As at December 31, 2017, there were approximately 1.7 million VIP awards outstanding. As at February 28, 2018, there were approximately 122.4 million common shares issued and outstanding.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As at December 31, 2017, 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	21,295	42,339	947,534	429,274	1,440,442
Operating lease obligations	10,716	19,129	10,303	28	40,176
Finance lease obligations	6,680	10,207	4,665	3,351	24,903
Processing and transportation agreements	26,002	34,343	10,960	35,153	106,458
Purchase obligations	21,105	16,649	1,664	—	39,418
Drilling and service agreements	10,255	46,129	20,132	5,110	81,626
Total contractual obligations and commitments	96,053	168,796	995,258	472,916	1,733,023

ASSET RETIREMENT OBLIGATIONS

As at December 31, 2017, asset retirement obligations were $517.2 million compared to $525.0 million as at December 31, 2016.

The decrease in asset retirement obligations is largely attributable to an extension to the estimated timing of abandonment spending. This decrease was partially offset by accretion expense and a weakening of the Canadian dollar against the Euro.

Vermilion has estimated the asset retirement obligations based on a total undiscounted future liability of $1.6 billion (2016 - $1.4 billion). These payments are expected to be made between 2018 and 2067, with the majority of spending occurring between 2027 and 2034 ($0.6 billion) and between 2063 and 2067 ($0.4 billion). Inflation rates used in determining the cash flow estimates were between 0.6% and 2.2% (2016 - between 0.5% and 2.2%). Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 3.8% (2016 - 3.8%) added to risk-free rates based on long-term, risk-free government bonds.

A 0.5% increase/decrease in the discount rate applied to asset retirement obligations would decrease/increase asset retirement obligations by approximately $40.0 million. A one year increase/decrease in the expected timing of abandonment spend would decrease/increase asset retirement obligations by approximately $20.0 million.

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 are 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 US dollars and as such an increase in the strength of the Canadian dollar relative to the US dollar may result in the receipt of fewer Canadian dollars with respect to our production. In addition, we incur expenses and capital costs in US 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. 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 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 and 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, 2017.

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

2018 Accounting Standards
On January 1, 2018, Vermilion will adopt IFRS 9 "Financial Instruments" and IFRS 15 "Revenue from Contracts with Customers".

IFRS 9 includes a new classification and measurement approach for financial assets and a forward-looking 'expected credit loss' model. Vermilion expects that there will be no material impact as a result of adopting IFRS 9. These changes are discussed in greater detail below:

- New classification and measurement approach for financial assets: IFRS 9 contains three classifications for financial assets - measured at amortized cost, fair value through other comprehensive income, and fair value through profit or loss. Vermilion's held for trading financial instruments will be classified as fair value through profit or loss while Vermilion's loans and receivables will be classified as measured at amortized cost. The new classification requirements are not expected to result in a change in the measured amounts of these financial instruments.
- Forward-looking 'expected credit loss' model: IFRS 9 includes a lifetime expected credit loss model that applies to Vermilion's accounts receivable. Based on the Company's actual credit loss experience and creditworthiness of Vermilion's customers and joint operations partners, the impact of adopting this credit loss model is not expected to be material.

IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Vermilion's revenue consists of the sale of petroleum and natural gas to customers at specified delivery points with pricing determined based on benchmark pricing plus or minus applicable offsets. Based on the Company's historic and outstanding contracts with customers, Vermilion anticipates that there will be no changes to the timing, measurement, or presentation of revenue upon adoption of IFRS 15. However, there will be additional disclosure requirements necessary to comply with IFRS 15. This additional disclosure will primarily relate to the disclosure of the disaggregation of revenue by commodity, information which is currently available within Vermilion's Management's Discussion and Analysis.

2019 Accounting Standard
Vermilion is required to adopt IFRS 16 "Leases" by January 1, 2019. IFRS 16 requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases. On adoption, non-current assets, current liabilities, and non-current liabilities on Vermilion's consolidated balance sheet will increase. Interest expense will be recognized on the lease obligation and lease payments will be applied against the lease obligation. This is expected to result in a decrease to both operating expense and general and administration expense, and an increase to fund flows from operations. The quantitative 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 2017 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;
- Continued comprehensive investigations of all our incidents and near misses to ensure root causes were identified and corrective actions effectively implemented;
- Rolled out “Vermilion High 5”, an individual safety awareness initiative aimed at keeping front line workers safe;
- Conducted a company wide review of contractor management, field supervision selection and onboarding, management of new and inexperienced workers, work procedures around mobile equipment;
- Further developed and validated critical procedures and implemented fit-for-purpose training and competency programs;
- Implemented a comprehensive HSE integration plan for Vermilion’s new and emerging operations;
- Reported our CO_2e emissions to the CDP and have been recognized as a Climate Leadership level (A-) performer. We are one of only 18 Energy Sector companies globally to receive a leadership score (Top 4%).

- Completed and published our Corporate Sustainability Report with emphasis on improving energy efficiency, greenhouse gas emissions reduction and water efficiency optimization;
- Managed our waste products by reducing, recycling and recovering;
- Reduced long-term environmental liabilities through decommissioning, abandoning and reclaiming well leases and facilities;
- Further refined and expanded our enterprise wide corporate risk register;
- Expanded 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 risks and energy type exposures;
- Continued the development of a robust hazard identification and risk mitigation program specific to environmentally sensitive areas;
- Continued the development of our Corporate Process Safety Management System with emphasis on Process Hazards Analysis;
- Further progressed our Asset Integrity Management System;
- Performed auditing, management inspections and workforce observations to measure compliance and identify potential hazards and apply risk reduction measures;
- Developed, communicated and measured against leading and lagging HSE key performance indicators; 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 understands our stakeholders' expectations that we deliver strong financial results in a responsible and ethical way. 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. Reflecting these priorities, we believe we are playing a meaningful role in the energy transition that is unfolding globally, within the universal context of the United Nations Sustainable Development Goals. These Global Goals provide an important call to action for sustainable, inclusive growth that supports an end to poverty, protection of the planet, and peace and prosperity for all people.

Our sustainability performance demonstrates our contribution to long-term economic growth, and the way we have shown that delivering shareholder value can go hand-in-hand with delivering sustainability. We began reporting on sustainability, or corporate social responsibility, in August 2014, using the comprehensive option within 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.

In December 2015, we further prioritized sustainability by implementing Integrated Sustainability as one of six strategic objectives for our global business. We believe that the integration of sustainability principles into our business is not only the right thing to do, it also increases shareholder returns, enhances our business development opportunities and reduces long-term risks to our business model. We defined our strategic objective as *Integrated* Sustainability because we believe sustainability impacts every business unit, department and employee in the company - and, in turn, they impact our sustainability. In keeping with this approach, our Board of Directors provides oversight of Vermilion's sustainability programs, with individual committees offering insight and guidance on specific economic, environmental, social and governance factors.

To support our sustainability strategy, Vermilion regularly communicates with its stakeholders, and we continually monitor trends and best practices in stakeholder engagement. 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; and
- economic success through a focus on operational excellence across our business, which includes technical and process excellence, efficiency, expertise and stakeholder relations.

For more information about how we manage sustainability, including climate-related risks, please see our detailed Sustainability Report online.

Vermilion's sustainability performance and reporting have earned consistently strong recognition from external stakeholders:

Accomplishments:

- In 2017, Vermilion was named to the CDP (formerly Carbon Disclosure Project) Climate Leadership Level rating of (A-). We were the only Canadian Energy Sector company, one of only two in North America, and 18 globally to achieve a Leadership Level score this year. As context, only 9% of 6,020 companies achieved an 'A or A-' grade for performance in 2017.
- Vermilion was one of only 193 companies globally to achieve CDP Climate "A" List recognition in 2016 and the only North American energy company on the list. Across all sectors, only three Canadian companies, including Vermilion, were awarded a position on 2016's Climate "A" List. Vermilion was one of only five oil and gas companies in the world to be named to the Climate "A" List.
- Vermilion has earned recognition on the Corporate Knights Future 40 Responsible Corporate Leaders in Canada listing every year since the list's inception in 2014; in 2017, we ranked 13th, and were the highest rated oil and gas company on the list.
- Between 2016 and 2017, Vermilion's MSCI ESG (environment, social and governance) rating increased from BBB to A, and our score on MSCI's Governance Metrics Report ranks Vermilion at 7.7/10 top decile performance globally.
- The Montreal-based Finance and Sustainability Initiative has selected Vermilion as the winner of the FSI Competition for Best Sustainability Report in the Non-Renewable Resources-Oil and Gas category for 2018.

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).

As a Canadian reporting issuer with securities listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE"), Vermilion Energy Inc. ("Vermilion") 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 U.S. Securities and Exchange Commission which give effect to the provisions of the *Sarbanes-Oxley Act of 2002*.

Our corporate governance practices also incorporate many "best practices" derived from those required to be followed by US domestic companies under the NYSE listing standards. We are required by Section 303A.11 of the NYSE Listed Company Manual to identify any significant ways in which our corporate governance practices differ from those required to be followed by US domestic companies under NYSE listing standards. We believe that there are no such significant differences in our corporate governance practices, except as follows:

- *Shareholder Approval of Equity Compensation Plans*. Section 303A.8 of the NYSE Listed Company Manual requires shareholder approval of all "equity compensation plans" and material revisions to those plans. The definition of "equity compensation plans" covers plans that provide for the delivery of newly issued securities, and also plans which rely on securities reacquired on the market by the issuing company for the purpose of redistribution to employees and directors. The TSX rules provide that equity compensation plans and material amendments thereto require shareholder approval only if they involve newly issued securities and the amendments are not otherwise addressed in the plan's amendment procedures. In addition, the TSX rules require that every three years after institution, all unallocated options, rights or other entitlements under equity compensation plans which does not have a fixed maximum aggregate of securities issuable must be approved by shareholders. Vermilion follows the TSX rules with respect to shareholder approval of equity compensation plans and material revisions to those plans.

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, 2017, 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, 2017. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2017 has been audited by Deloitte LLP, as reflected in their report included in the 2017 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, 2017, 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 Dec 31, 2017			Year Ended Dec 31, 2017			Three Months Ended Dec 31, 2016	Year Ended Dec 31, 2016
	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	55.17	1.88	**31.21**	51.36	2.34	**30.72**	33.48	26.81
Royalties	(6.26)	(0.07)	**(3.07)**	(6.21)	(0.09)	**(3.09)**	(3.51)	(2.28)
Transportation	(2.40)	(0.15)	**(1.60)**	(2.25)	(0.18)	**(1.61)**	(1.66)	(1.63)
Operating	(7.65)	(1.19)	**(7.38)**	(7.85)	(1.19)	**(7.47)**	(8.62)	(7.59)
Operating netback	38.86	0.47	**19.16**	35.05	0.88	**18.55**	19.69	15.31
General and administration			**(0.84)**			**(0.89)**	(0.97)	(1.25)
Fund flows from operations netback			**18.32**			**17.66**	18.72	14.06
France								
Sales	75.13	—	**75.13**	67.08	1.52	**67.08**	63.71	55.15
Royalties	(10.11)	—	**(10.11)**	(7.15)	(2.30)	**(7.15)**	(5.93)	(6.05)
Transportation	(4.27)	—	**(4.27)**	(3.66)	—	**(3.66)**	(3.53)	(3.30)
Operating	(13.67)	—	**(13.67)**	(12.76)	—	**(12.76)**	(10.17)	(11.17)
Operating netback	47.08	—	**47.08**	43.51	(0.78)	**43.51**	44.08	34.63
General and administration			**(4.06)**			**(3.40)**	(4.52)	(4.27)
Other income			**—**			**—**	3.39	0.85
Current income taxes			**(2.24)**			**(2.64)**	(2.54)	(0.64)
Fund flows from operations netback			**40.78**			**37.47**	40.41	30.57
Netherlands								
Sales	66.38	7.87	**47.41**	56.90	7.18	**43.24**	40.84	34.15
Royalties	—	(0.13)	**(0.75)**	—	(0.12)	**(0.69)**	(0.46)	(0.50)
Operating	—	(1.36)	**(8.09)**	—	(1.43)	**(8.49)**	(8.90)	(7.05)
Operating netback	66.38	6.38	**38.57**	56.90	5.63	**34.06**	31.48	26.60
General and administration			**(0.63)**			**(0.89)**	(0.26)	(0.52)
Current income taxes			**8.08**			**1.33**	0.16	(2.25)
Fund flows from operations netback			**46.02**			**34.50**	31.38	23.83
Germany								
Sales	72.58	7.07	**50.22**	63.91	6.38	**44.37**	36.54	31.97
Royalties	(1.72)	(0.97)	**(4.78)**	(1.70)	(0.85)	**(4.30)**	(0.06)	(2.30)
Transportation	(5.86)	(0.35)	**(3.09)**	(8.00)	(0.46)	**(4.01)**	(1.65)	(3.16)
Operating	(30.31)	(1.84)	**(16.01)**	(32.30)	(1.17)	**(13.03)**	(17.44)	(13.62)
Operating netback	34.69	3.91	**26.34**	21.91	3.90	**23.03**	17.39	12.89
General and administration			**(5.53)**			**(5.02)**	(7.73)	(9.15)
Fund flows from operations netback			**20.81**			**18.01**	9.66	3.74
Ireland								
Sales	—	8.47	**50.79**	—	7.19	**43.14**	44.29	35.16
Transportation	—	(0.29)	**(1.74)**	—	(0.24)	**(1.46)**	(1.77)	(2.09)
Operating	—	(0.58)	**(3.45)**	—	(0.83)	**(4.95)**	(5.34)	(6.01)
Operating netback	—	7.60	**45.60**	—	6.12	**36.73**	37.18	27.06
General and administration			**(0.60)**			**(0.65)**	(1.58)	(1.54)
Fund flows from operations netback			**45.00**			**36.08**	35.60	25.52

	Three Months Ended Dec 31, 2017			Year Ended Dec 31, 2017			Three Months Ended Dec 31, 2016	Year Ended Dec 31, 2016
	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Crude Oil, Condensate & NGLs $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Australia								
Sales	83.32	—	**83.32**	73.99	—	**73.99**	69.05	60.33
Operating	(28.11)	—	**(28.11)**	(24.03)	—	**(24.03)**	(26.83)	(20.95)
PRRT [1]	(8.25)	—	**(8.25)**	(9.50)	—	**(9.50)**	(2.82)	(0.69)
Operating netback	46.96	—	**46.96**	40.46	—	**40.46**	39.40	38.69
General and administration			**(7.37)**			**(3.93)**	(3.60)	(2.82)
Corporate income taxes			**(4.05)**			**(2.17)**	(4.87)	(3.32)
Fund flows from operations netback			**35.54**			**34.36**	30.93	32.55
United States								
Sales	65.58	2.48	**62.40**	57.64	2.05	**53.84**	53.58	43.70
Royalties	(17.96)	(0.88)	**(17.16)**	(15.93)	(0.80)	**(14.99)**	(16.05)	(12.95)
Transportation	(0.22)	—	**(0.21)**	(0.16)	—	**(0.14)**	—	—
Operating	(6.08)	—	**(5.70)**	(6.50)	—	**(5.95)**	(7.91)	(7.85)
Operating netback	41.32	1.60	**39.33**	35.05	1.25	**32.76**	29.62	22.90
General and administration			**(18.28)**			**(15.22)**	(23.02)	(21.65)
Fund flows from operations netback			**21.05**			**17.54**	6.60	1.25
Total Company								
Sales	66.93	5.23	**47.49**	61.44	4.91	**44.41**	45.93	37.88
Realized hedging gain	(0.88)	(0.22)	**(1.12)**	0.50	(0.01)	**0.19**	0.34	2.81
Royalties	(6.78)	(0.14)	**(3.52)**	(5.47)	(0.14)	**(3.01)**	(2.65)	(2.33)
Transportation	(2.76)	(0.17)	**(1.79)**	(2.46)	(0.19)	**(1.76)**	(1.69)	(1.70)
Operating	(13.33)	(1.13)	**(9.76)**	(13.19)	(1.13)	**(9.79)**	(10.54)	(9.53)
PRRT [1]	(1.18)	—	**(0.53)**	(1.71)	—	**(0.80)**	(0.28)	(0.07)
Operating netback	42.00	3.57	**30.77**	39.11	3.44	**29.24**	31.11	27.06
General and administration			**(2.39)**			**(2.20)**	(2.03)	(2.27)
Interest expense			**(2.05)**			**(2.32)**	(2.55)	(2.44)
Realized foreign exchange gain (loss)			**0.43**			**0.09**	0.23	0.17
Other income			**0.02**			**0.03**	0.70	0.17
Corporate income taxes [1]			**0.35**			**(0.50)**	(1.03)	(0.78)
Fund flows from operations netback			**27.13**			**24.34**	26.43	21.91

[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, 2017:

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 (bbld) [2]
Dated Brent												
Swap	Jan 2018 - Dec 2018		CAD	—	—	—	—	—	—	500	76.25	—
3-Way Collar	Jul 2017 - Jun 2018		USD	2,000	55.00	2,000	64.06	2,000	45.00	—	—	—
3-Way Collar	Jul 2017 - Dec 2018		USD	2,000	48.89	2,000	55.00	2,000	42.50	—	—	—
3-Way Collar	Oct 2017 - Dec 2018		USD	2,000	50.50	2,000	55.75	2,000	43.00	—	—	—
3-Way Collar	Dec 2017 - Mar 2018		USD	500	57.50	500	62.50	500	52.50	—	—	—
3-Way Collar	Jan 2018 - Jun 2018		USD	1,000	53.58	1,000	59.50	1,000	46.25	—	—	—
Collar	Jan 2018 - Dec 2018		USD	1,000	50.00	1,000	57.50	—	—	—	—	—
Swap	Jan 2018 - Mar 2018		USD	—	—	—	—	—	—	750	67.22	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	1,000	55.00	—
Swaption	Apr 2018 - Mar 2019	Jan 31, 2018	USD	—	—	—	—	—	—	500	60.00	—
Swaption	Apr 2018 - Mar 2019	Mar 30, 2018	USD	—	—	—	—	—	—	750	64.33	—
WTI												
Swap	Jan 2018 - Jan 2018		CAD	—	—	—	—	—	—	1,000	75.50	—
3-Way Collar	Jan 2018 - Jun 2018		USD	500	48.50	500	56.00	500	42.50	—	—	—
Collar	Jan 2018 - Dec 2018		USD	500	50.00	500	55.00	—	—	—	—	—
Swap	Jan 2018 - Jun 2018		USD	—	—	—	—	—	—	500	54.00	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	1,000	54.00	—
Swaption	Apr 2018 - Mar 2019	Jan 31, 2018	USD	—	—	—	—	—	—	250	54.00	—

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												
Swap	Jan 2018 - Dec 2018		CAD	—	—	—	—	—	—	9,478	2.80	—
AECO Basis (AECO less NYMEX HH)												
Swap	Oct 2017 - Dec 2018		USD	—	—	—	—	—	—	10,000	(1.03)	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	20,000	(0.95)	—
Swap	Jan 2019 - Jun 2020		USD	—	—	—	—	—	—	2,500	(0.93)	—
NYMEX HH												

3-Way Collar	Oct 2017 - Dec 2018	USD	10,000	3.11	10,000	3.40	10,000	2.40	—	—	—
3-Way Collar	Jan 2018 - Dec 2018	USD	10,000	3.06	10,000	3.40	10,000	2.40	—	—	—
Swap	Apr 2018 - Dec 2018	USD	—	—	—	—	—	—	10,000	3.10	—

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract 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]
NBP												
3-Way Collar	Apr 2018 - Sep 2018		EUR	4,913	4.73	4,913	5.42	4,913	3.52	—	—	—
3-Way Collar	Jan 2019 - Dec 2019		EUR	14,740	4.82	14,740	5.52	14,740	3.74	—	—	—
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	3.74	—	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	14,740	4.85	14,740	5.63	14,740	3.88	—	—	—
Swap	Jan 2018 - Jan 2018		EUR	—	—	—	—	—	—	4,913	6.80	—
Call	Oct 2018 - Mar 2019		EUR	—	—	2,457	6.42	—	—	—	—	—
Put	Apr 2018 - Sep 2018		EUR	—	—	—	—	2,457	4.98	—	—	—
Collar	Jan 2018 - Dec 2018		GBP	2,500	3.15	2,500	3.82	—	—	—	—	—
Swap	Apr 2017 - Mar 2018		GBP	—	—	—	—	—	—	5,300	4.20	—
Swap	Jan 2018 - Dec 2018		GBP	—	—	—	—	—	—	2,500	4.04	5,000
NBP Basis (NBP less NYMEX HH)												
Collar	Jan 2018 - Dec 2018		USD	2,500	1.85	2,500	4.00	—	—	—	—	—
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	—	—	—	—
TTF												
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	12,284	4.75	12,284	5.48	12,284	3.25	—	—	—
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	3.13	—	—	—
3-Way Collar	Jan 2019 - Dec 2019		EUR	9,827	4.92	9,827	5.48	9,827	3.66	—	—	—
Collar	Jul 2016 - Mar 2018		EUR	2,457	5.61	4,913	6.90	—	—	—	—	—
Collar	Jan 2018 - Dec 2018		EUR	4,913	4.40	4,913	5.31	—	—	—	—	—
Swap	Jul 2016 - Jun 2018		EUR	—	—	—	—	—	—	2,559	5.89	—
Swap	Apr 2017 - Jun 2018		EUR	—	—	—	—	—	—	4,299	4.50	—
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	Jul 2018 - Dec 2019		EUR	—	—	—	—	—	—	4,913	4.98	—
Swap	Jan 2019 - Dec 2019		EUR	—	—	—	—	—	—	2,457	4.92	—
Swaption	Jan 2019 - Dec 2020	April 30, 2018	EUR	—	—	—	—	—	—	9,827	5.28	—

Cross Currency Interest Rate		Receive Notional amount (USD)	Rate (LIBOR +)	Pay Notional amount(CAD)	Rate (CDOR +)
Swap	Jan 2018	603,793,015	1.70 %	775,800,000	1.11 %

(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.

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Three Months Ended			Year Ended	
	Dec 31, 2017	Sep 30, 2017	Dec 31, 2016	Dec 31, 2017	Dec 31, 2016
Drilling and development	**61,911**	75,837	66,437	**290,593**	241,545
Exploration and evaluation	**12,392**	15,545	445	**29,856**	863
Capital expenditures	**74,303**	91,382	66,882	**320,449**	242,408
Property acquisition	**3,048**	20,976	78,713	**27,637**	98,524
Acquisitions	**3,048**	20,976	78,713	**27,637**	98,524

By category ($M)	Three Months Ended			Year Ended	
	Dec 31, 2017	Sep 30, 2017	Dec 31, 2016	Dec 31, 2017	Dec 31, 2016
Drilling, completion, new well equip and tie-in, workovers and recompletions	**45,533**	62,451	53,867	**225,668**	166,795
Production equipment and facilities	**18,109**	16,982	14,427	**59,629**	49,453
Seismic, studies, land and other	**10,661**	11,949	(1,412)	**35,152**	26,160
Capital expenditures	**74,303**	91,382	66,882	**320,449**	242,408
Acquisitions	**3,048**	20,976	78,713	**27,637**	98,524
Total capital expenditures and acquisitions	**77,351**	112,358	145,595	**348,086**	340,932

Capital expenditures by country ($M)	Three Months Ended			Year Ended	
	Dec 31, 2017	Sep 30, 2017	Dec 31, 2016	Dec 31, 2017	Dec 31, 2016
Canada	**26,865**	43,746	16,895	**148,667**	62,706
France	**20,027**	15,756	31,127	**73,381**	68,472
Netherlands	**12,300**	11,590	5,737	**31,575**	23,740
Germany	**5,279**	3,020	1,694	**9,531**	3,803
Ireland	**327**	1,101	1,711	**551**	9,375
Australia	**7,192**	10,154	5,236	**29,942**	59,910
United States	**1,018**	1,362	4,037	**19,074**	13,539
Corporate	**1,295**	4,653	445	**7,728**	863
Total capital expenditures	**74,303**	91,382	66,882	**320,449**	242,408

Acquisitions by country ($M)	Three Months Ended			Year Ended	
	Dec 31, 2017	Sep 30, 2017	Dec 31, 2016	Dec 31, 2017	Dec 31, 2016
Canada	**788**	19,712	1,378	**22,011**	13,309
Netherlands	**(38)**	14	28,259	**(24)**	28,259
Germany	**—**	—	48,377	**—**	48,377
United States	**91**	1,250	377	**3,403**	5,935
Corporate	**2,207**	—	322	**2,247**	2,644
Total acquisitions	**3,048**	20,976	78,713	**27,637**	98,524

Supplemental Table 4: Production

	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15
Canada												
Crude oil & condensate (bbls/d)	**9,703**	9,288	9,205	7,987	7,945	8,984	9,453	10,317	10,413	11,030	11,843	12,163
NGLs (bbls/d)	**5,235**	4,891	3,745	2,670	2,444	2,448	2,687	2,633	2,710	2,678	2,094	1,706
Natural gas (mmcf/d)	**107.91**	103.92	93.68	85.74	75.12	77.62	87.44	97.16	87.90	71.94	64.66	61.78
Total (boe/d)	**32,923**	31,499	28,563	24,947	22,910	24,368	26,713	29,141	27,773	25,698	24,713	24,165
% of consolidated	**45%**	46%	43%	38%	38%	37%	42%	44%	45%	47%	48%	48%
France												
Crude oil (bbls/d)	**11,215**	10,918	11,368	10,834	11,220	11,827	12,326	12,220	12,537	12,310	12,746	11,463
Natural gas (mmcf/d)	**—**	—	—	0.01	0.38	0.42	0.54	0.44	1.36	1.47	1.03	—
Total (boe/d)	**11,215**	10,918	11,368	10,836	11,283	11,897	12,416	12,293	12,763	12,555	12,917	11,463
% of consolidated	**15%**	16%	17%	17%	19%	19%	19%	19%	21%	22%	25%	23%
Netherlands												
Condensate (bbls/d)	**105**	74	104	76	57	86	96	114	110	109	112	63
Natural gas (mmcf/d)	**55.66**	34.90	31.58	39.92	41.15	47.62	49.18	53.40	56.34	53.56	32.43	36.41
Total (boe/d)	**9,381**	5,890	5,368	6,729	6,915	8,023	8,293	9,015	9,500	9,035	5,517	6,132
% of consolidated	**13%**	9%	8%	10%	11%	13%	13%	14%	16%	16%	11%	12%
Germany												
Crude oil (bbls/d)	**1,148**	1,054	1,047	989	—	—	—	—	—	—	—	—
Natural gas (mmcf/d)	**18.19**	20.12	19.86	19.39	14.80	14.52	14.31	15.96	16.17	14.00	16.18	16.80
Total (boe/d)	**4,180**	4,407	4,357	4,220	2,467	2,420	2,385	2,660	2,695	2,333	2,696	2,801
% of consolidated	**6%**	7%	6%	7%	4%	4%	4%	4%	4%	4%	5%	6%
Ireland												
Natural gas (mmcf/d)	**56.23**	49.04	63.81	64.82	62.92	59.28	47.26	33.90	0.12	—	—	—
Total (boe/d)	**9,372**	8,173	10,634	10,803	10,486	9,879	7,877	5,650	20	—	—	—
% of consolidated	**13%**	12%	16%	17%	17%	16%	12%	9%	—	—	—	—
Australia												
Crude oil (bbls/d)	**4,993**	5,473	6,054	6,581	6,388	6,562	6,083	6,180	7,824	6,433	5,865	5,672
% of consolidated	**7%**	8%	9%	10%	10%	10%	9%	9%	13%	11%	11%	11%
United States												
Crude oil (bbls/d)	**667**	880	747	365	362	383	458	368	420	226	123	153
NGLs (bbls/d)	**43**	56	76	24	23	30	26	39	29	—	—	—
Natural gas (mmcf/d)	**0.29**	0.64	0.44	0.20	0.18	0.20	0.20	0.26	0.20	—	—	—
Total (boe/d)	**758**	1,043	896	422	414	447	518	450	483	226	123	153
% of consolidated	**1%**	2%	1%	1%	1%	1%	1%	1%	1%	—	—	—
Consolidated												
Crude oil, condensate & NGLs (bbls/d)	**33,109**	32,634	32,346	29,526	28,439	30,320	31,129	31,871	34,043	32,786	32,783	31,220
% of consolidated	**45%**	48%	48%	46%	47%	48%	48%	49%	56%	58%	63%	62%
Natural gas (mmcf/d)	**238.28**	208.62	209.36	210.07	194.54	199.65	198.93	201.11	162.09	140.97	114.29	115.00
% of consolidated	**55%**	52%	52%	54%	53%	52%	52%	51%	44%	42%	37%	38%
Total (boe/d)	**72,822**	67,403	67,240	64,537	60,863	63,596	64,285	65,389	61,058	56,280	51,831	50,386

	2017	2016	2015	2014	2013	2012
Canada						
Crude oil & condensate (bbls/d)	**9,051**	9,171	11,357	12,491	8,387	7,659
NGLs (bbls/d)	**4,144**	2,552	2,301	1,233	1,666	1,232
Natural gas (mmcf/d)	**97.89**	84.29	71.65	55.67	42.39	37.50
Total (boe/d)	**29,510**	25,771	25,598	23,001	17,117	15,142
% of consolidated	**45%**	40%	46%	47%	41%	40%
France						
Crude oil (bbls/d)	**11,084**	11,896	12,267	11,011	10,873	9,952
Natural gas (mmcf/d)	**—**	0.44	0.97	—	3.40	3.59
Total (boe/d)	**11,085**	11,970	12,429	11,011	11,440	10,550
% of consolidated	**16%**	19%	23%	22%	28%	28%
Netherlands						
Condensate (bbls/d)	**90**	88	99	77	64	67
Natural gas (mmcf/d)	**40.54**	47.82	44.76	38.20	35.42	34.11
Total (boe/d)	**6,847**	8,058	7,559	6,443	5,967	5,751
% of consolidated	**10%**	13%	14%	13%	15%	15%
Germany						
Crude oil (bbls/d)	**1,060**	—	—	—	—	—
Natural gas (mmcf/d)	**19.39**	14.90	15.78	14.99	—	—
Total (boe/d)	**4,291**	2,483	2,630	2,498	—	—
% of consolidated	**6%**	4%	5%	5%	—	—
Ireland						
Natural gas (mmcf/d)	**58.43**	50.89	0.03	—	—	—
Total (boe/d)	**9,737**	8,482	5	—	—	—
% of consolidated	**14%**	13%	—	—	—	—
Australia						
Crude oil (bbls/d)	**5,770**	6,304	6,454	6,571	6,481	6,360
% of consolidated	**8%**	10%	12%	13%	16%	17%
United States						
Crude oil (bbls/d)	**666**	393	231	49	—	—
NGLs (bbls/d)	**50**	29	7	—	—	—
Natural gas (mmcf/d)	**0.39**	0.21	0.05	—	—	—
Total (boe/d)	**781**	457	247	49	—	—
% of consolidated	**1%**	1%	—	—	—	—
Consolidated						
Crude oil, condensate & NGLs (bbls/d)	**31,915**	30,433	32,716	31,432	27,471	25,270
% of consolidated	**47%**	48%	60%	63%	67%	67%
Natural gas (mmcf/d)	**216.64**	198.55	133.24	108.85	81.21	75.20
% of consolidated	**53%**	52%	40%	37%	33%	33%
Total (boe/d)	**68,021**	63,526	54,922	49,573	41,005	37,803

Supplemental Table 5: Segmented Financial Results

	Three Months Ended Dec 31, 2017								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Drilling and development	26,865	19,557	2,874	4,078	327	7,192	1,018	—	61,911
Exploration and evaluation	—	470	9,426	1,201	—	—	—	1,295	12,392
Oil and gas sales to external customers	94,522	78,778	40,914	18,898	43,793	36,086	4,350	—	317,341
Royalties	(9,301)	(10,599)	(647)	(1,798)	—	—	(1,196)	—	(23,541)
Revenue from external customers	85,221	68,179	40,267	17,100	43,793	36,086	3,154	—	293,800
Transportation	(4,836)	(4,475)	—	(1,164)	(1,496)	—	(15)	—	(11,986)
Operating	(22,356)	(14,332)	(6,981)	(6,025)	(2,977)	(12,172)	(397)	—	(65,240)
General and administration	(2,540)	(4,259)	(546)	(2,080)	(517)	(3,193)	(1,274)	(1,532)	(15,941)
PRRT	—	—	—	—	—	(3,572)	—	—	(3,572)
Corporate income taxes	—	(2,348)	6,975	—	—	(1,755)	—	(542)	2,330
Interest expense	—	—	—	—	—	—	—	(13,710)	(13,710)
Realized gain on derivative instruments	—	—	—	—	—	—	—	(7,493)	(7,493)
Realized foreign exchange gain	—	—	—	—	—	—	—	2,899	2,899
Realized other income	—	—	—	—	—	—	—	166	166
Fund flows from operations	55,489	42,765	39,715	7,831	38,803	15,394	1,468	(20,212)	181,253

	Year Ended December 31, 2017								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,542,193	831,783	203,929	295,026	667,068	236,677	73,867	124,422	3,974,965
Drilling and development	148,667	71,087	15,107	6,165	551	29,942	19,074	—	290,593
Exploration and evaluation	—	2,294	16,468	3,366	—	—	—	7,728	29,856
Oil and gas sales to external customers	330,903	268,103	108,060	68,696	153,330	154,391	15,355	—	1,098,838
Royalties	(33,258)	(28,565)	(1,722)	(6,655)	—	—	(4,276)	—	(74,476)
Revenue from external customers	297,645	239,538	106,338	62,041	153,330	154,391	11,079	—	1,024,362
Transportation	(17,368)	(14,627)	—	(6,207)	(5,205)	—	(41)	—	(43,448)
Operating	(80,444)	(51,002)	(21,212)	(20,176)	(17,596)	(50,139)	(1,698)	—	(242,267)
General and administration	(9,604)	(13,585)	(2,212)	(7,767)	(2,320)	(8,194)	(4,341)	(6,350)	(54,373)
PRRT	—	—	—	—	—	(19,819)	—	—	(19,819)
Corporate income taxes	—	(10,556)	3,331	—	—	(4,536)	—	(527)	(12,288)
Interest expense	—	—	—	—	—	—	—	(57,313)	(57,313)
Realized gain on derivative instruments	—	—	—	—	—	—	—	4,721	4,721
Realized foreign exchange gain	—	—	—	—	—	—	—	2,316	2,316
Realized other income	—	—	—	—	—	—	—	674	674
Fund flows from operations	190,229	149,768	86,245	27,891	128,209	71,703	4,999	(56,479)	602,565

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 use free cash flow 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. We also assess free cash flow as a percentage of fund flows from operations, which is a measure of the percentage of fund flows from operations that is retained for incremental investing and financing activities.

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 Plan. 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 and payout as a percentage of fund flows from operations (also referred to as the **sustainability ratio**) 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:

($M)	Three Months Ended			Year Ended	
	Dec 31, 2017	**Sep 30, 2017**	**Dec 31, 2016**	**Dec 31, 2017**	**Dec 31, 2016**
Dividends declared	**78,653**	78,293	76,096	**311,397**	299,070
Shares issued for the Dividend Reinvestment Plan	**(21,817)**	(23,929)	(43,580)	**(110,493)**	(192,998)
Net dividends	**56,836**	54,364	32,516	**200,904**	106,072
Drilling and development	**61,911**	75,837	66,437	**290,593**	241,545
Exploration and evaluation	**12,392**	15,545	445	**29,856**	863
Asset retirement obligations settled	**3,216**	1,749	3,327	**9,334**	9,617
Payout	**134,355**	147,495	102,725	**530,687**	358,097
% of fund flows from operations	**74%**	113%	69%	**88%**	70%

('000s of shares)	As at		
	Dec 31, 2017	**Sep 30, 2017**	**Dec 31, 2016**
Shares outstanding	**122,119**	121,585	118,263
Potential shares issuable pursuant to the VIP	**3,021**	2,868	3,090
Diluted shares outstanding	**125,140**	124,453	121,353

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

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

Stephen P. Larke [3, 4]
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, 4]
Calgary, Alberta

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

William Roby [5, 6]
Katy, Texas

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 Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
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
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mcf	thousand cubic feet
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
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 at the Title Transfer Facility

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

Jenson Tan
Vice President Business Development

Lars Glemser
Director Finance

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Kyle Preston
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

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

Sylvain Nothhelfer
Managing Director - France Business Unit

Scott Seatter
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

HSBC Bank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian 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

	Virtual Trading Point.
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

AUSTRALIA

Bruce D. Lake
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
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
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mcf	thousand cubic feet
mmbtu	million British thermal units
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, 2017. The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2017 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, 2017.

("Anthony Marino")

Anthony Marino
President & Chief Executive Officer
February 28, 2018

("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.

Opinion on Internal Control over Financial Reporting
We have audited the internal control over financial reporting of Vermilion Energy Inc. and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB) and Canadian generally accepted auditing standards, the consolidated financial statements as at and for the year ended December 31, 2017, of the Company and our report dated February 28, 2018, expressed an unmodified/ unqualified opinion on those financial statements.

Basis for Opinion
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 to Shareholders. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting
A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
February 28, 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Vermilion Energy Inc.

Opinion on the Consolidated Financial Statements
We have audited the accompanying consolidated financial statements of Vermilion Energy Inc. and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of net earnings (loss) and comprehensive income (loss), consolidated statements of cash flows, and consolidated statements of changes in shareholders' equity for the years then ended, and the related notes, including a summary of significant accounting policies and other explanatory information (collectively referred to as the "financial statements").

In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2017 and December 31, 2016, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on Internal Control over Financial Reporting
We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2018 expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion
Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these 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 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 financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement, whether due to fraud or error. Those standards also require that we comply with ethical requirements. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. Further, we are required to be independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and to fulfill our other ethical responsibilities in accordance with these requirements.

An audit includes performing procedures to assess the risks of material misstatement of the financial statements, whether due to fraud or error, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a reasonable basis for our audit opinion.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
February 28, 2018

We have served as the Company's auditor since 2000.

CONSOLIDATED BALANCE SHEET
(THOUSANDS OF CANADIAN DOLLARS)

	Note	December 31, 2017	December 31, 2016
ASSETS			
Current			
Cash and cash equivalents	19	**46,561**	62,775
Accounts receivable		**165,760**	131,719
Crude oil inventory		**17,105**	14,528
Derivative instruments	9	**17,988**	4,336
Prepaid expenses		**14,432**	12,548
		261,846	225,906
Derivative instruments	9	**2,552**	1,157
Deferred taxes	11	**80,324**	152,046
Exploration and evaluation assets	7	**292,278**	274,830
Capital assets	6	**3,337,965**	3,433,245
		3,974,965	4,087,184
LIABILITIES			
Current			
Accounts payable and accrued liabilities		**219,084**	181,557
Dividends payable	13	**26,256**	25,426
Derivative instruments	9	**78,905**	47,660
Income taxes payable		**39,061**	36,219
		363,306	290,862
Derivative instruments	9	**12,348**	27,484
Long-term debt	12	**1,270,330**	1,362,192
Finance lease obligation	10	**15,807**	19,628
Asset retirement obligations	8	**517,180**	525,022
Deferred taxes	11	**253,108**	283,533
		2,432,079	2,508,721
SHAREHOLDERS' EQUITY			
Shareholders' capital	13	**2,650,706**	2,452,722
Contributed surplus		**84,354**	101,788
Accumulated other comprehensive income		**71,829**	30,339
Deficit		**(1,264,003)**	(1,006,386)
		1,542,886	1,578,463
		3,974,965	4,087,184

APPROVED BY THE BOARD

(Signed "Catherine L. Williams") *(Signed "Anthony Marino")*

Catherine L. Williams, Director Anthony Marino, Director

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

		Year Ended	
	Note	December 31, 2017	December 31, 2016
REVENUE			
Petroleum and natural gas sales		**1,098,838**	882,791
Royalties		**(74,476)**	(54,284)
Petroleum and natural gas revenue		**1,024,362**	828,507
EXPENSES			
Operating	19	**242,267**	222,185
Transportation		**43,448**	39,511
Equity based compensation	15	**61,579**	69,235
(Gain) loss on derivative instruments	9	**(3,659)**	72,617
Interest expense		**57,313**	56,957
General and administration	19	**54,373**	52,829
Foreign exchange gain		**(74,058)**	(3,249)
Other income		**(37)**	(3,896)
Accretion	8	**26,971**	24,783
Depletion and depreciation	6, 7	**491,683**	528,002
Impairment	6, 7	**—**	14,762
Gain on business combination	5	**—**	(22,001)
		899,880	1,051,735
EARNINGS (LOSS) BEFORE INCOME TAXES		**124,482**	(223,228)
TAXES	11		
Deferred		**30,117**	(82,855)
Current		**32,107**	19,678
		62,224	(63,177)
NET EARNINGS (LOSS)		**62,258**	(160,051)
OTHER COMPREHENSIVE INCOME (LOSS)			
Currency translation adjustments		**41,490**	(83,308)
COMPREHENSIVE INCOME (LOSS)		**103,748**	(243,359)
NET EARNINGS (LOSS) PER SHARE	16		
Basic		**0.52**	(1.38)
Diluted		**0.51**	(1.38)
WEIGHTED AVERAGE SHARES OUTSTANDING ('000s)	16		
Basic		**120,582**	115,695
Diluted		**122,408**	115,695

CONSOLIDATED STATEMENTS OF CASH FLOWS
(THOUSANDS OF CANADIAN DOLLARS)

	Note	Year Ended December 31, 2017	Year Ended December 31, 2016
OPERATING			
Net earnings (loss)		**62,258**	(160,051)
Adjustments:			
Accretion	8	**26,971**	24,783
Depletion and depreciation	6, 7	**491,683**	528,002
Impairment	6, 7	**—**	14,762
Gain on business combination	5	**—**	(22,001)
Unrealized loss on derivative instruments	9	**1,062**	137,993
Equity based compensation	15	**61,579**	69,235
Unrealized foreign exchange (gain) loss		**(71,742)**	792
Unrealized other expense		**637**	131
Deferred taxes	11	**30,117**	(82,855)
Asset retirement obligations settled	8	**(9,334)**	(9,617)
Changes in non-cash operating working capital	19	**665**	8,366
Cash flows from operating activities		**593,896**	509,540
INVESTING			
Drilling and development	6	**(290,593)**	(241,545)
Exploration and evaluation	7	**(29,856)**	(863)
Property acquisitions	5, 6, 7	**(27,637)**	(98,524)
Changes in non-cash investing working capital	19	**407**	(12,298)
Cash flows used in investing activities		**(347,679)**	(353,230)
FINANCING			
(Repayments) borrowings on the revolving credit facility	12	**(450,646)**	202,617
Issuance (repayment) of senior unsecured notes	12	**391,906**	(225,000)
Decrease in finance lease obligation	10	**(4,874)**	(4,270)
Cash dividends	13	**(200,074)**	(104,723)
Cash flows used in investing activities		**(263,688)**	(131,376)
Foreign exchange gain (loss) on cash held in foreign currencies		**1,257**	(3,835)
Net change in cash and cash equivalents		**(16,214)**	21,099
Cash and cash equivalents, beginning of period		**62,775**	41,676
Cash and cash equivalents, end of period	19	**46,561**	62,775
Supplementary information for cash flows from operating activities			
Interest paid		**49,721**	60,221
Income taxes paid (refunded)		**29,265**	(10,535)

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

	Year Ended	
	December 31, 2017	**December 31, 2016**
SHAREHOLDERS' CAPITAL		
Balance, beginning of period	**2,452,722**	2,181,089
Shares issued for the Dividend Reinvestment Plan	**110,493**	192,998
Vesting of equity based awards	**69,743**	67,146
Equity based compensation	**9,270**	8,247
Share-settled dividends on vested equity based awards	**8,478**	3,242
Balance, end of period	**2,650,706**	2,452,722
CONTRIBUTED SURPLUS		
Balance, beginning of period	**101,788**	107,946
Equity based compensation	**52,309**	60,988
Vesting of equity based awards	**(69,743)**	(67,146)
Balance, end of period	**84,354**	101,788
ACCUMULATED OTHER COMPREHENSIVE INCOME		
Balance, beginning of period	**30,339**	113,647
Currency translation adjustments	**41,490**	(83,308)
Balance, end of period	**71,829**	30,339
DEFICIT		
Balance, beginning of period	**(1,006,386)**	(544,023)
Net earnings (loss)	**62,258**	(160,051)
Dividends declared	**(311,397)**	(299,070)
Share-settled dividends on vested equity based awards	**(8,478)**	(3,242)
Balance, end of period	**(1,264,003)**	(1,006,386)
TOTAL SHAREHOLDERS' EQUITY	**1,542,886**	1,578,463

Please refer to Financial Statement Note 13 (Shareholders' Capital) and Note 15 (Equity Based Compensation) for additional information.

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 the 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 less distributed earnings of Vermilion Energy Inc.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2017 AND 2016
(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, 3rd Avenue SW, Calgary, Alberta, Canada.

These consolidated financial statements were approved and authorized for issuance by Vermilion's Board of Directors on February 28, 2018.

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 included the accounts of Vermilion Energy Inc. and its subsidiaries. Vermilion's subsidiaries include entities in each of the jurisdictions that Vermilion operates as described in Note 4 including: Canada, France, Netherlands, Germany, Ireland (through an Irish Branch of a Cayman Islands incorporated company), Australia, and the United States. Vermilion Energy Inc. directly or indirectly through holding companies owns all of the voting securities of each material subsidiary. 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 and license acquisition costs; and costs for the 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 results in 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. Interest expense is recognized on the finance lease obligation using the effective interest method.

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. The cost of crude oil inventory produced includes related operating expense, royalties, and depletion determined on a weighted-average basis.

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 of 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
On initial recognition, financial instruments are measured at fair value. 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 earnings (loss) per share is calculated by dividing net earnings (loss) by the weighted-average number of shares outstanding during the period.

Diluted net earnings (loss) per share is calculated by dividing net earnings (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 basic weighted-average number of shares outstanding and, to the extent inclusion reduces diluted 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 transaction 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. Foreign currency transaction 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. Foreign operation 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.

Business Combinations
Acquisitions of corporations or groups of assets are accounted for as business combinations using the acquisition method if the acquired assets constitute a business. Under the acquisition method, assets acquired and liabilities assumed in a business combination are measured at the fair value. If applicable, the excess or deficiency of net assets acquired compared to consideration paid is recognized as a gain on business combination or as goodwill on the consolidated balance sheet. Acquisition-related costs incurred to effect a business combination are expensed in the period incurred.

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, the expected timing of expenditures, and the underlying risk inherent to the asset based on the jurisdiction it relates to. 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. Deferred tax assets and related valuation assessments are based on estimates of future profitability.

3. CHANGES TO ACCOUNTING PRONOUNCEMENTS

On January 1, 2018, Vermilion will adopt IFRS 9 "Financial Instruments" and IFRS 15 "Revenue from Contracts with Customers".

IFRS 9 includes a new classification and measurement approach for financial assets and a forward-looking 'expected credit loss' model. Vermilion expects that there will be no material impact as a result of adopting IFRS 9. These changes are discussed in greater detail below:

- New classification and measurement approach for financial assets: IFRS 9 contains three classifications for financial assets - measured at amortized cost, fair value through other comprehensive income, and fair value through profit or loss. Vermilion's held for trading financial instruments will be classified as fair value through profit or loss while Vermilion's loans and receivables will be classified as measured at amortized cost. The new classification requirements are not expected to result in a change in the measured amounts of these financial instruments.
- Forward-looking 'expected credit loss' model: IFRS 9 includes a lifetime expected credit loss model that applies to Vermilion's accounts receivable. Based on the Company's actual credit loss experience and creditworthiness of Vermilion's customers and joint operations partners, the impact of adopting this credit loss model is not expected to be material.

IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Vermilion's revenue consists of the sale of petroleum and natural gas to customers at specified delivery points with pricing determined based on benchmark pricing plus or minus applicable offsets. Based on the Company's historic and outstanding contracts with customers, Vermilion anticipates that there will be no material changes to the timing, measurement, or presentation of revenue upon adoption of IFRS 15. However, there will be additional disclosure requirements necessary to comply with IFRS 15. This additional disclosure will primarily relate to the disclosure of the disaggregation of revenue by commodity, information which is currently available within Vermilion's Management's Discussion and Analysis.

Vermilion is required to adopt IFRS 16 "Leases" by January 1, 2019. IFRS 16 requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases. On adoption, non-current assets, current liabilities, and non-current liabilities on Vermilion's consolidated balance sheet will increase. Interest expense will be recognized on the lease obligation and lease payments will be applied against the lease obligation. This is expected to result in a decrease to operating expense and general and administration expense. The quantitative 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, 2017 and 2016 were to one customer in each respective segment.

	Year Ended December 31, 2017								
($M)	**Canada**	**France**	**Netherlands**	**Germany**	**Ireland**	**Australia**	**United States**	**Corporate**	**Total**
Total assets	1,542,193	831,783	203,929	295,026	667,068	236,677	73,867	124,422	3,974,965
Drilling and development	148,667	71,087	15,107	6,165	551	29,942	19,074	—	290,593
Exploration and evaluation	—	2,294	16,468	3,366	—	—	—	7,728	29,856
Oil and gas sales to external customers	330,903	268,103	108,060	68,696	153,330	154,391	15,355	—	1,098,838
Royalties	(33,258)	(28,565)	(1,722)	(6,655)	—	—	(4,276)	—	(74,476)
Revenue from external customers	297,645	239,538	106,338	62,041	153,330	154,391	11,079	—	1,024,362
Transportation	(17,368)	(14,627)	—	(6,207)	(5,205)	—	(41)	—	(43,448)
Operating	(80,444)	(51,002)	(21,212)	(20,176)	(17,596)	(50,139)	(1,698)	—	(242,267)
General and administration	(9,604)	(13,585)	(2,212)	(7,767)	(2,320)	(8,194)	(4,341)	(6,350)	(54,373)
PRRT	—	—	—	—	—	(19,819)	—	—	(19,819)
Corporate income taxes	—	(10,556)	3,331	—	—	(4,536)	—	(527)	(12,288)
Interest expense	—	—	—	—	—	—	—	(57,313)	(57,313)
Realized gain on derivative instruments	—	—	—	—	—	—	—	4,721	4,721
Realized foreign exchange gain	—	—	—	—	—	—	—	2,316	2,316
Realized other income	—	—	—	—	—	—	—	674	674
Fund flows from operations	190,229	149,768	86,245	27,891	128,209	71,703	4,999	(56,479)	602,565

	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

Reconciliation of fund flows from operations to net earnings (loss):

	Year Ended	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Fund flows from operations	**602,565**	510,791
Accretion	**(26,971)**	(24,783)
Depletion and depreciation	**(491,683)**	(528,002)
Impairment	**—**	(14,762)
Gain on business combination	**—**	22,001
Unrealized loss on derivative instruments	**(1,062)**	(137,993)
Equity based compensation	**(61,579)**	(69,235)
Unrealized foreign exchange gain (loss)	**71,742**	(792)
Unrealized other expense	**(637)**	(131)
Deferred tax	**(30,117)**	82,855
Net earnings (loss)	**62,258**	(160,051)

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

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.

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)	2017	2016
Balance at January 1	**3,433,245**	3,467,369
Additions	**290,593**	241,545
Transfers from exploration and evaluation assets	**8,187**	—
Property acquisitions	**25,390**	189,853
Changes in asset retirement obligations	**(48,187)**	149,492
Depletion and depreciation	**(479,698)**	(491,508)
Recognition of finance lease asset	**—**	960
Impairment	**—**	(14,762)
Foreign exchange	**108,435**	(109,704)
Balance at December 31	**3,337,965**	3,433,245
Cost	**6,539,052**	6,256,485
Accumulated depletion and depreciation	**(3,201,087)**	(2,823,240)
Carrying amount at December 31	**3,337,965**	3,433,245

2017 Impairment Assessment
As at December 31, 2017, Vermilion did not identify any indicators of impairment.

On December 19, 2017, France's Parliament passed legislation impacting oil and gas exploration and production on French territories. The legislation eliminates the issuance of future oil and gas exploration licenses and places restrictions on oil and gas development starting in 2040. Vermilion assessed whether there are any indications of impairment in our cash generating units in France as a result of this legislation and determined that the value of the cash generating units have not significantly declined. The impact of this legislation is a decrease of less than 2% of Vermilion's reserves in France. As such, Vermilion concluded that the legislation does not constitute an indicator of impairment.

2016 Impairment
As at December 31, 2016 Vermilion did not identify any indicators of impairment. However, 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.

7. EXPLORATION AND EVALUATION ASSETS

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

($M)	2017	2016
Balance at January 1	**274,830**	308,192
Additions	**29,856**	863
Property acquisitions	**2,247**	2,644
Changes in asset retirement obligations	**(30)**	14
Transfers to capital assets	**(8,187)**	—
Depreciation	**(11,727)**	(35,238)
Foreign exchange	**5,289**	(1,645)
Balance at December 31	**292,278**	274,830
Cost	**354,615**	333,835
Accumulated depreciation	**(62,337)**	(59,005)
Carrying amount at December 31	**292,278**	274,830

8. ASSET RETIREMENT OBLIGATIONS

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

($M)	2017	2016
Balance at January 1	**525,022**	305,613
Additional obligations recognized	**3,273**	68,288
Changes in estimates	**(48,904)**	3,454
Obligations settled	**(9,334)**	(9,617)
Accretion	**26,971**	24,783
Changes in discount rates	**(2,586)**	144,729
Foreign exchange	**22,738**	(12,228)
Balance at December 31	**517,180**	525,022

Vermilion has estimated the asset retirement obligations based on a total undiscounted future liability of $1.6 billion (2016 - $1.4 billion). These payments are expected to be made between 2018 and 2067, with the majority of spending occurring between 2027 and 2034 ($0.6 billion) and between 2063 and 2067 ($0.4 billion). Inflation rates used in determining the cash flow estimates were between 0.6% and 2.2% (2016 - between 0.5% and 2.2%). Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 3.8% (2016 - 3.8%) added to risk-free rates based on long-term, risk-free government bonds.

The risk-free rates used as inputs to discount the obligations were as follows:

	Dec 31, 2017	Dec 31, 2016
Canada	**2.3%**	2.3%
France	**1.8%**	1.7%
Netherlands	**0.5%**	(0.3)%
Germany	**1.0%**	0.9%
Ireland	**0.4%**	0.5%
Australia	**2.9%**	3.2%
USA	**2.4%**	2.6%

A 0.5% increase/decrease in the discount rate applied to asset retirement obligations would decrease/increase asset retirement obligations by approximately $40.0 million. A one year increase/decrease in the expected timing of abandonment spend would decrease/increase asset retirement obligations by approximately $20.0 million.

9. DERIVATIVE INSTRUMENTS

The following tables summarize Vermilion's outstanding risk management positions as at December 31, 2017:

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 (bbld) [2]
Dated Brent												
Swap	Jan 2018 - Dec 2018		CAD	—	—	—	—	—	—	500	76.25	—
3-Way Collar	Jul 2017 - Jun 2018		USD	2,000	55.00	2,000	64.06	2,000	45.00	—	—	—
3-Way Collar	Jul 2017 - Dec 2018		USD	2,000	48.89	2,000	55.00	2,000	42.50	—	—	—
3-Way Collar	Oct 2017 - Dec 2018		USD	2,000	50.50	2,000	55.75	2,000	43.00	—	—	—
3-Way Collar	Dec 2017 - Mar 2018		USD	500	57.50	500	62.50	500	52.50	—	—	—
3-Way Collar	Jan 2018 - Jun 2018		USD	1,000	53.58	1,000	59.50	1,000	46.25	—	—	—
Collar	Jan 2018 - Dec 2018		USD	1,000	50.00	1,000	57.50	—	—	—	—	—
Swap	Jan 2018 - Mar 2018		USD	—	—	—	—	—	—	750	67.22	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	1,000	55.00	—
Swaption	Apr 2018 - Mar 2019	Jan 31, 2018	USD	—	—	—	—	—	—	500	60.00	—
Swaption	Apr 2018 - Mar 2019	Mar 30, 2018	USD	—	—	—	—	—	—	750	64.33	—
WTI												
Swap	Jan 2018 - Jan 2018		CAD	—	—	—	—	—	—	1,000	75.50	—
3-Way Collar	Jan 2018 - Jun 2018		USD	500	48.50	500	56.00	500	42.50	—	—	—
Collar	Jan 2018 - Dec 2018		USD	500	50.00	500	55.00	—	—	—	—	—
Swap	Jan 2018 - Jun 2018		USD	—	—	—	—	—	—	500	54.00	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	1,000	54.00	—
Swaption	Apr 2018 - Mar 2019	Jan 31, 2018	USD	—	—	—	—	—	—	250	54.00	—

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												
Swap	Jan 2018 - Dec 2018		CAD	—	—	—	—	—	—	9,478	2.80	—
AECO Basis (AECO less NYMEX HH)												
Swap	Oct 2017 - Dec 2018		USD	—	—	—	—	—	—	10,000	(1.03)	—
Swap	Jan 2018 - Dec 2018		USD	—	—	—	—	—	—	20,000	(0.95)	—
Swap	Jan 2019 - Jun 2020		USD	—	—	—	—	—	—	2,500	(0.93)	—
NYMEX HH												
3-Way Collar	Oct 2017 - Dec 2018		USD	10,000	3.11	10,000	3.40	10,000	2.40	—	—	—
3-Way Collar	Jan 2018 - Dec 2018		USD	10,000	3.06	10,000	3.40	10,000	2.40	—	—	—
Swap	Apr 2018 - Dec 2018		USD	—	—	—	—	—	—	10,000	3.10	—

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract 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]
NBP												
3-Way Collar	Apr 2018 - Sep 2018		EUR	4,913	4.73	4,913	5.42	4,913	3.52	—	—	—
3-Way Collar	Jan 2019 - Dec 2019		EUR	14,740	4.82	14,740	5.52	14,740	3.74	—	—	—
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	3.74	—	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	14,740	4.85	14,740	5.63	14,740	3.88	—	—	—
Swap	Jan 2018 - Jan 2018		EUR	—	—	—	—	—	—	4,913	6.80	—
Call	Oct 2018 - Mar 2019		EUR	—	—	2,457	6.42	—	—	—	—	—
Put	Apr 2018 - Sep 2018		EUR	—	—	—	—	2,457	4.98	—	—	—
Collar	Jan 2018 - Dec 2018		GBP	2,500	3.15	2,500	3.82	—	—	—	—	—
Swap	Apr 2017 - Mar 2018		GBP	—	—	—	—	—	—	5,300	4.20	—
Swap	Jan 2018 - Dec 2018		GBP	—	—	—	—	—	—	2,500	4.04	5,000
NBP Basis (NBP less NYMEX HH)												
Collar	Jan 2018 - Dec 2018		USD	2,500	1.85	2,500	4.00	—	—	—	—	—
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	—	—	—	—
TTF												
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	12,284	4.75	12,284	5.48	12,284	3.25	—	—	—
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	3.13	—	—	—
3-Way Collar	Jan 2019 - Dec 2019		EUR	9,827	4.92	9,827	5.48	9,827	3.66	—	—	—
Collar	Jul 2016 - Mar 2018		EUR	2,457	5.61	4,913	6.90	—	—	—	—	—
Collar	Jan 2018 - Dec 2018		EUR	4,913	4.40	4,913	5.31	—	—	—	—	—
Swap	Jul 2016 - Jun 2018		EUR	—	—	—	—	—	—	2,559	5.89	—
Swap	Apr 2017 - Jun 2018		EUR	—	—	—	—	—	—	4,299	4.50	—
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	Jul 2018 - Dec 2019		EUR	—	—	—	—	—	—	4,913	4.98	—
Swap	Jan 2019 - Dec 2019		EUR	—	—	—	—	—	—	2,457	4.92	—
Swaption	Jan 2019 - Dec 2020	April 30, 2018	EUR	—	—	—	—	—	—	9,827	5.28	—

Cross Currency Interest Rate		Receive Notional amount (USD)	Rate (LIBOR +)	Pay Notional amount(CAD)	Rate (CDOR +)
Swap	Jan 2018	603,793,015	1.70%	775,800,000	1.11%

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract 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.

The following table reconciles the change in the fair value of Vermilion's derivative instruments:

	Year Ended	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Fair value of contracts, beginning of year	**(69,651)**	68,342
Reversal of opening contracts settled during the year	**43,324**	(55,214)
Realized gain on contracts settled during the year	**4,721**	65,376
Unrealized loss during the year on contracts outstanding at the end of the year	**(44,386)**	(82,779)
Net receipt from counterparties on contract settlements during the year	**(4,721)**	(65,376)
Fair value of contracts, end of year	**(70,713)**	(69,651)
Comprised of:		
Current derivative asset	**17,988**	4,336
Current derivative liability	**(78,905)**	(47,660)
Non-current derivative asset	**2,552**	1,157
Non-current derivative liability	**(12,348)**	(27,484)
Fair value of contracts, end of year	**(70,713)**	(69,651)

The (gain) loss on derivative instruments for 2017 and 2016 were comprised of the following:

	Year Ended	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Realized gain on contracts settled during the year	**(4,721)**	(65,376)
Reversal of opening contracts settled during the year	**(43,324)**	55,214
Unrealized loss during the year on contracts outstanding at the end of the year	**44,386**	82,779
(Gain) loss on derivative instruments	**(3,659)**	72,617

10. LEASES

Vermilion had the following future commitments associated with its operating leases:

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Less than 1 year	**10,716**	12,683
1 - 3 years	**19,129**	21,087
4 - 5 years	**10,303**	18,228
After 5 years	**28**	1,657
Total minimum lease payments	**40,176**	53,655

A solution gas facility used in Vermilion's southeast Saskatchewan operations has been recorded as a finance lease. As at December 31, 2017 the carrying amount of the asset included in capital assets is $22.9 million (2016 - $26.1 million).

Vermilion had the following future commitments associated with its finance lease:

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Less than 1 year	**6,680**	6,495
1 - 3 years	**10,207**	12,990
4 - 5 years	**4,665**	6,043
After 5 years	**3,351**	4,501
Total minimum lease payments	**24,903**	30,029
Amounts representing interest	**(3,526)**	(3,894)
Present value of net minimum lease payments	**21,377**	26,135
Current portion of finance lease obligation	**(5,570)**	(6,507)
Non-current portion of finance lease obligation	**15,807**	19,628

11. TAXES

The following table reconciles Vermilion's deferred tax asset and liability:

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Deferred tax liabilities:		
Capital assets	**(259,236)**	(265,772)
Non-capital losses	**34,703**	20,561
Asset retirement obligations	**(27,868)**	(20,577)
Unrealized foreign exchange	**(13,355)**	(15,386)
Derivative contracts	**11,386**	—
Other	**1,262**	(2,359)
Deferred tax liabilities	**(253,108)**	(283,533)
Deferred tax assets:		
Non-capital losses	**342,202**	155,447
Capital assets	**(294,178)**	(55,718)
Asset retirement obligations	**28,056**	28,960
Derivative contracts	**10,164**	18,806
Unrealized foreign exchange	**(7,927)**	(72)
Other	**2,007**	4,623
Deferred tax assets	**80,324**	152,046

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, 2017**	**Dec 31, 2016**
Earnings (loss) before income taxes	**124,482**	(223,228)
Canadian corporate tax rate	**27.0%**	27.0%
Expected tax expense (recovery)	**33,610**	(60,272)
Increase (decrease) in taxes resulting from:		
Petroleum resource rent tax rate (PRRT) differential [(1)]	**3,531**	1,064
Foreign tax rate differentials [(1), (2)]	**7,146**	(16,675)
Equity based compensation expense	**10,343**	14,987
Amended returns and changes to estimated tax pools and tax positions	**(17,246)**	6,451
Statutory rate changes and the estimated reversal rates associated with temporary differences [(3)]	**(16,449)**	(53,150)
De-recognition of deferred tax assets	**44,608**	46,253
Adjustment for uncertain tax positions	**2,191**	3,675
Other non-deductible items	**(5,510)**	(5,510)
Provision for income taxes	**62,224**	(63,177)

(1) 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%.

(2) The applicable tax rates for 2017 were: 34.4% in France, 50.0% in the Netherlands, 26.3% in Germany, 25% in Ireland, and 35% in the United States.

(3) On December 22, 2017, the Tax Cuts and Jobs Act was signed into law in the United States reducing the U.S. federal corporate income tax rate from 35% to 21%. On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French standard corporate income tax rate from 34.43% to 25.825% by 2022.

At December 31, 2017, Vermilion had $2.0 billion (2016 - $1.0 billion) of unused tax losses of which $0.5 billion (2016 - $0.5 billion) related to Vermilion's Canada segment and expire between 2030 and 2037. The majority of the remaining unused tax losses relate to Vermilion's Ireland segment and do not expire. The year-over-year increase in unused tax losses is due to a reclassification of Vermilion's Ireland tax pools from capital asset tax pools to tax loss pools - both types of tax pools can be applied directly against taxable income and neither type of tax pool is subject to expiration.

At December 31, 2017, Vermilion has de-recognized $145.6 million (2016 - $96.1 million) of deferred tax assets relating to the aforementioned non-expiring tax loss pools in Ireland as there is uncertainty as to the Company's ability to fully utilize such losses based on forecasted commodity prices in effect as at December 31, 2017.

The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have not been recognized as at December 31, 2017 is approximately $1.2 billion (2016 – approximately $1.5 billion).

12. LONG-TERM DEBT

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

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Revolving credit facility	**899,595**	1,362,192
Senior unsecured notes	**370,735**	—
Long-term debt	**1,270,330**	1,362,192

The following table reconciles the change in Vermilion's long-term debt:

($M)	**2017**	**2016**
Balance at January 1	**1,362,192**	1,387,899
(Repayments) borrowings on the revolving credit facility	**(450,646)**	200,378
Issuance (repayment) of senior unsecured notes	**391,906**	(225,000)
Amortization of transaction costs and prepaid interest	**2,012**	2,337
Foreign exchange	**(35,134)**	(3,422)
Balance at December 31	**1,270,330**	1,362,192

Revolving Credit Facility

At December 31, 2017 and 2016, Vermilion had in place a bank revolving credit facility maturing May 31, 2021 with the following terms:

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Total facility amount	**1,400,000**	2,000,000
Amount drawn	**(899,595)**	(1,362,192)
Letters of credit outstanding	**(7,400)**	(20,100)
Unutilized capacity	**493,005**	617,708

The facility can be extended from time to time 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 is secured by various fixed and floating charges against the subsidiaries of Vermilion.

The facility bears interest at a rate applicable to demand loans plus applicable margins. For the year ended December 31, 2017, the effective interest rate was 3.7% (2016 - 4.0%). For the year ended December 31, 2017, a 1% increase in the average Canadian prime interest rate would decrease net earnings before tax by $8.0 million (2016 - $11.7 million).

In April 2017, as a result of proceeds from the issuance of the senior unsecured notes and projected liquidity requirements, Vermilion elected to reduce the total facility amount from $2.0 billion to $1.4 billion.

As at December 31, 2017, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	**Limit**	**Dec 31, 2017**	**Dec 31, 2016**
Consolidated total debt to consolidated EBITDA	4.0	**1.87**	2.36
Consolidated total senior debt to consolidated EBITDA	3.5	**1.30**	2.32
Consolidated total senior debt to total capitalization	55%	**32%**	46%

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.

As at December 31, 2017 and 2016, Vermilion was in compliance with the above covenants.

Senior Unsecured Notes

On March 13, 2017, Vermilion issued US $300.0 million of senior unsecured notes at par. The notes bear interest at a rate of 5.625% per annum, to be paid semi-annually on March 15 and September 15. The notes mature on March 15, 2025. As direct senior unsecured obligations of Vermilion, the notes rank equally with existing and future senior unsecured indebtedness of the Company.

The senior unsecured notes were recognized at amortized cost and include the transaction costs directly related to the issuance.

Vermilion may, at its option, redeem the notes prior to maturity as follows:
- Prior to March 15, 2020, Vermilion may redeem up to 35% of the original principal amount of the senior unsecured notes with the proceeds of certain equity offerings by the Company at a redemption price of 105.625% of the principal amount plus any accrued and unpaid interest to the applicable redemption date.
- Prior to March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at a price equal to 100% of the principal amount of the senior unsecured notes, plus an applicable premium and any accrued and unpaid interest.
- On or after March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table plus any accrued and unpaid interest.

Year	Redemption price
2020	104.219%
2021	102.813%
2022	101.406%
2023 and thereafter	100.000%

13. SHAREHOLDERS' CAPITAL

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

	2017		2016	
Shareholders' Capital	Shares ('000s)	Amount ($M)	Shares ('000s)	Amount ($M)
Balance at January 1	**118,263**	**2,452,722**	111,991	2,181,089
Shares issued for the Dividend Reinvestment Plan	**2,429**	**110,493**	4,672	192,998
Vesting of equity based awards	**1,060**	**69,743**	1,320	67,146
Shares issued for equity based compensation	**197**	**9,270**	193	8,247
Share-settled dividends on vested equity based awards	**170**	**8,478**	87	3,242
Balance at December 31	**122,119**	**2,650,706**	118,263	2,452,722

Vermilion is authorized to issue an unlimited number of common shares with no par value.

Dividends are approved by the Board of Directors and are paid monthly. Dividends declared to shareholders for the year ended December 31, 2017 were $311.4 million or $2.58 per common share (2016 - $299.1 million or $2.58 per common share).

Subsequent to the end of year-end and prior to the consolidated financial statements being authorized for issue on February 28, 2018, Vermilion declared dividends of $52.6 million or $0.215 per share for each of January and February of 2018.

14. CAPITAL DISCLOSURES

Vermilion defines capital as net debt (long-term debt plus net working capital) and shareholders' capital.

Vermilion monitors the ratio of net debt to fund flows from operations. As at December 31, 2017 our ratio of net debt to trailing fund flows from operations is 2.3 (2016 - 2.8). Vermilion manages the ratio of net debt to fund flows from operations (refer to Financial Statement Note 4 - Segmented Information) by aligning capital expenditures, dividends, and asset retirement obligations with expected fund flows from operations. Vermilion intends for the ratio of net debt to fund flows from operations to trend towards 1.5 over time.

The following table calculates Vermilion's ratio of net debt to fund flows from operations:

	Year Ended	
($M except as indicated)	**Dec 31, 2017**	**Dec 31, 2016**
Long-term debt	**1,270,330**	1,362,192
Current liabilities	**363,306**	290,862
Current assets	**(261,846)**	(225,906)
Net debt	**1,371,790**	1,427,148
Fund flows from operations	**602,565**	510,791
Ratio of net debt to fund flows from operations	**2.3**	2.8

15. EQUITY BASED COMPENSATION

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

Number of Awards ('000s)	**2017**	**2016**
Opening balance	**1,738**	1,711
Granted	**563**	777
Vested	**(539)**	(628)
Modified	**—**	11
Forfeited	**(77)**	(133)
Closing balance	**1,685**	1,738

For the year ended December 31, 2017, the awards granted had a weighted average fair value of $49.44 (2016 - $38.41). Equity based compensation expense is calculated based on the number of VIP awards outstanding multiplied by the estimated performance factor that will be realized upon vesting (2017 - 1.9; 2016 - 1.9) adjusted by an estimated annual forfeiture rate (2017 - 4.4%; 2016 - 4.6%). Equity based compensation expense related to the VIP of $52.3 million was recorded during the year ended December 31, 2017 (2016 - $61.0 million).

16. PER SHARE AMOUNTS

Basic and diluted net earnings (loss) per share have been determined based on the following:

	Year Ended	
($M except per share amounts)	**Dec 31, 2017**	**Dec 31, 2016**
Net earnings (loss)	**62,258**	(160,051)
Basic weighted average shares outstanding ('000s)	**120,582**	115,695
Dilutive impact of VIP ('000s)	**1,826**	—
Diluted weighted average shares outstanding ('000s)	**122,408**	115,695
Basic earnings per share	**0.52**	(1.38)
Diluted earnings per share	**0.51**	(1.38)

17. FINANCIAL INSTRUMENTS

Classification of Financial Instruments

The following table summarizes information relating to Vermilion's financial instruments:

	As at Dec 31, 2017		As at Dec 31, 2016	
	Carrying value	**Fair value**	**Carrying value**	**Fair value**
FINANCIAL ASSETS				
Held for trading				
Cash and cash equivalents	**46,561**	**46,561**	62,775	62,775
Derivative assets	**20,540**	**20,540**	5,493	5,493
Loans and receivables				
Accounts receivable	**165,760**	**165,760**	131,719	131,719
FINANCIAL LIABILITIES				
Held for trading				
Derivative liabilities	**(91,253)**	**(91,253)**	(75,144)	(75,144)
Other financial liabilities				
Accounts payable and accrued liabilities	**(219,084)**	**(219,084)**	(181,557)	(181,557)
Dividends payable	**(26,256)**	**(26,256)**	(25,426)	(25,426)
Long-term debt	**(1,270,330)**	**(1,274,891)**	(1,362,192)	(1,362,192)

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 and the senior unsecured notes (which are included in long-term debt as at December 31, 2017) 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.
- 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, 2017 and 2016.

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, accounts payables, long-term debt, derivative assets and derivative liabilities. These financial instruments are primarily denominated in the US dollar and the Euro. 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 revolving credit facility, which consists of short-term borrowing instruments that bear interest at market rates. Thus, changes in interest rates could result in an increase or decrease in the amount paid by Vermilion to service this debt.

Vermilion managed exposure to interest rate risk in 2017 by reducing the drawn amount on its revolving credit facility through the issuance of the US $300.0 million of senior unsecured notes which bear interest at a fixed 5.625% per annum. Additionally, throughout both 2016 and 2017, Vermilion had in place $200 million in interest rate swaps that mitigated some of the effects of changes in variable interest rates. Subsequent to 2017, as a result of favourable changes to interest rate curves resulting in an increase in the mark-to-market value of these interest rate swaps, these interest rate swaps were monetized.

The following table summarizes the increase (positive values) or decrease (negative values) to net earnings before tax 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, 2017	Dec 31, 2016
Currency risk - Euro to Canadian dollar		
$0.01 increase in strength of the Canadian dollar against the Euro	**(4,607)**	(859)
$0.01 decrease in strength of the Canadian dollar against the Euro	**4,607**	859
Currency risk - US dollar to Canadian dollar		
$0.01 increase in strength of the Canadian dollar against the US $	**2,239**	(9,184)
$0.01 decrease in strength of the Canadian dollar against the US $	**(2,239)**	9,184
Commodity price risk - Crude oil		
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(21,616)**	(26,513)
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**19,845**	18,882
Commodity price risk - European natural gas		
€ 0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	**(32,642)**	36,999
€ 0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	**25,321**	(33,019)

The table above shows the before tax effect on net earnings for a $0.01 change in the Canadian dollar against the US dollar based on long-term debt and other financial instruments.

As at December 31, 2017, Vermilion had US $0.6 billion in cross currency interest rate swaps as well as offsetting borrowings of $US 0.6 billion on the revolving credit facility. As such, the $2.2 million increase or decrease shown above for the year ended December 31, 2017 primarily related to Vermilion's US $300.0 million in senior unsecured notes issued in 2017.

As at December 31, 2016, Vermilion had US $0.9 billion in cross currency interest rate swaps 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 (London Interbank Offered Rate) plus applicable margins. As this transaction occurred subsequent to December 31, 2016, it was not included in the calculations shown in the above table. If included, the before tax effect on net earnings for a $0.01 increase/decrease in the Canadian dollar against the US dollar as at December 31, 2016 would have been a decrease/increase of $0.3 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, 2017, Vermilion's maximum exposure to receivable credit risk was $186.3 million (December 31, 2016 - $137.2 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 0.7% (2016 - 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, 2017	99,092	138,273	7,974	912,306
December 31, 2016	79,509	120,233	7,241	1,377,819

18. 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, 2017 and 2016:

	Year Ended	
($M)	Dec 31, 2017	Dec 31, 2016
Short-term benefits	**5,183**	4,748
Share-based payments	**20,135**	20,169
	25,318	24,917
Number of individuals included in the above amounts	**20**	18

During the year ended December 31, 2017, Vermilion recorded $0.2 million of office rent recoveries (2016 - $0.2 million) relating to an office sub-lease to a company whose Managing Director is also a member of Vermilion's Board of Directors. This related party transaction is provided in the normal course of business under the same commercial terms and conditions as transactions with unrelated companies and is recorded at the exchange amount.

19. SUPPLEMENTAL INFORMATION

Changes in non-cash working capital was comprised of the following:

	Year Ended	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Changes in:		
Accounts receivable	**(34,041)**	28,780
Crude oil inventory	**(2,577)**	1,311
Prepaid expenses	**(1,884)**	1,762
Accounts payable and accrued liabilities	**37,527**	(67,190)
Income taxes payable	**2,842**	30,213
Foreign exchange	**(795)**	1,192
Changes in non-cash working capital	**1,072**	(3,932)
Changes in non-cash operating working capital	**665**	8,366
Changes in non-cash investing working capital	**407**	(12,298)
Changes in non-cash working capital	**1,072**	(3,932)

Cash and cash equivalents was comprised of the following:

	As at	
($M)	**Dec 31, 2017**	**Dec 31, 2016**
Cash on deposit with financial institutions	**46,229**	62,614
Guaranteed investment certificates	**332**	161
Cash and cash equivalents	**46,561**	62,775

Wages and benefits included in operating expenses and general and administration expenses were:

	Year Ended	
($M)	**2017**	**2016**
Operating expense	**48,823**	45,061
General and administration expense	**36,708**	35,347
Wages and benefits	**85,531**	80,408

20. SUBSEQUENT EVENTS

On February 15, 2018, Vermilion acquired all of the issued and outstanding shares of a private producer with assets in southeast Saskatchewan and southwest Manitoba. The acquisition is comprised of light oil producing fields near Vermilion's existing operations in southeast Saskatchewan. Total consideration of $90.8 million, which includes both cash paid to the shareholders' of the acquiree and the assumption of the acquiree's long-term debt, was funded through Vermilion's revolving credit facility.

Given the recent timing of the acquisition, at the time these financial statements were authorized for issue, the initial accounting for the business combination is incomplete. Accordingly, not all relevant disclosures are available for the business combination. The Company will report the purchase price allocation and related disclosures in Vermilion's interim consolidated financial statements for the three months ended March 31, 2018.

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

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

Stephen P. Larke [3, 4]
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, 4]
Calgary, Alberta

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

William Roby [5, 6]
Katy, Texas

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 Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
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
GJ	gigajoules
HH	Henry Hub, a reference price paid for natural gas in US dollars at Erath, Louisiana
mbbls	thousand barrels
mcf	thousand cubic feet
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
MWh	megawatt hour
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
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 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

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

Jenson Tan
Vice President Business Development

Lars Glemser
Director Finance

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Kyle Preston
Director Investor Relations

Mike Prinz
Director Information Technology & Information Systems

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

Sylvain Nothhelfer
Managing Director - France Business Unit

Scott Seatter
Managing Director - Netherlands Business Unit

Albrecht Moehring
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake
Managing Director - Australia Business Unit

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Alberta Treasury Branches

Bank of America N.A., Canada Branch

BNP Paribas, Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

HSBC Bank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Wells Fargo Bank N.A., Canadian 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

Exhibit 99.4

Deloitte LLP
700, 850 2 Street SW
Calgary, AB T2P 0R8
Canada

Tel: 403-267-1700
Fax: 587-774-5379
www.deloitte.ca

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use of our reports dated February 28, 2018 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, 2017.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
March 1, 2018

Exhibit 99.5

CONSENT OF GLJ PETROLEUM CONSULTANTS LTD.

Dear Sirs:

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, 2017, in this Annual Report on Form 40-F of Vermilion Energy Inc.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Jodi L. Anhorn
Jodi L. Anhorn, M.Sc., P. Eng.
Executive Vice President

Calgary, Alberta
February 1, 2018

4100, 400 - 3rd Ave SW Calgary, AB, Canada T2P 4H2 I tel 403-266-9500 I gljpc.com

Exhibit 99.6

FORM 52-109F1
CERTIFICATION OF ANNUAL FILINGS - FULL CERTIFICATE

I, ***Anthony Marino, President and Chief Executive Officer of Vermilion Energy Inc.*** , certify the following:

1. ***Review:*** I have reviewed the AIF, if any, annual financial statements and annual MD&A, including, for greater certainty, all documents and information that are incorporated by reference in the AIF (together, the "annual filings") of *Vermilion Energy Inc.* (the "issuer") for the financial year ended *December 31, 2017*.

2. ***No misrepresentations:*** Based on my knowledge, having exercised reasonable diligence, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, for the period covered by the annual filings.

3. ***Fair presentation:*** Based on my knowledge, having exercised reasonable diligence, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date of and for the periods presented in the annual filings.

4. ***Responsibility:*** The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* , for the issuer.

5. ***Design:*** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer's other certifying officer(s) and I have, as at the financial year end

   (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that
      (i) material information relating to the issuer is made known to us by others, particularly during the period in which the annual filings are being prepared; and
      (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and
   (b) designed ICFR, or caused it 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 the issuer's GAAP.

5.1 ***Control framework:*** The control framework the issuer's other certifying officer(s) and I used to design the issuer's ICFR is based on the framework in Internal Control – Integrated Framework (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

5.2 ***ICFR - material weakness relating to design:*** N/A

5.3 ***Limitation on scope of design:*** N/A

6. ***Evaluation:*** The issuer's other certifying officer(s) and I have

   (a) evaluated, or caused to be evaluated under our supervision, the effectiveness of the issuer's DC&P at the financial year end and the issuer has disclosed in its annual MD&A our conclusions about the effectiveness of DC&P at the financial year end based on that evaluation; and
   (b) evaluated, or caused to be evaluated under our supervision, the effectiveness of the issuer's ICFR at the financial year end and the issuer has disclosed in its annual MD&A
      (i) our conclusions about the effectiveness of ICFR at the financial year end based on that evaluation; and
      (ii) N/A

7. ***Reporting changes in ICFR:*** The issuer has disclosed in its annual MD&A any change in the issuer's ICFR that occurred during the period beginning on *October 1, 2017 and ended on December 31, 2017* that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

8. ***Reporting to the issuer's auditors and board of directors or audit committee:*** The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of ICFR, to the issuer's auditors, and the board of directors or the audit committee of the board of directors any fraud that involves management or other employees who have a significant role in the issuer's ICFR.

Date: **March 1, 2018**

(Signed "Anthony Marino")
Anthony Marino, President & Chief Executive Officer

Exhibit 99.7

FORM 52-109F1
CERTIFICATION OF ANNUAL FILINGS - FULL CERTIFICATE

I, ***Curtis Hicks, Executive Vice President and Chief Financial Officer of Vermilion Energy Inc.*** , certify the following:

1. ***Review:*** I have reviewed the AIF, if any, annual financial statements and annual MD&A, including, for greater certainty, all documents and information that are incorporated by reference in the AIF (together, the "annual filings") of *Vermilion Energy Inc.* (the "issuer") for the financial year ended *December 31, 2017*.

2. ***No misrepresentations:*** Based on my knowledge, having exercised reasonable diligence, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, for the period covered by the annual filings.

3. ***Fair presentation:*** Based on my knowledge, having exercised reasonable diligence, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date of and for the periods presented in the annual filings.

4. ***Responsibility:*** The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR"), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* , for the issuer.

5. ***Design:*** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer's other certifying officer(s) and I have, as at the financial year end

   (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that
      (i) material information relating to the issuer is made known to us by others, particularly during the period in which the annual filings are being prepared; and
      (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and
   (b) designed ICFR, or caused it 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 the issuer's GAAP.

5.1 ***Control framework:*** The control framework the issuer's other certifying officer(s) and I used to design the issuer's ICFR is based on the framework in Internal Control – Integrated Framework (2013 Framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

5.2 ***ICFR - material weakness relating to design:*** N/A

5.3 ***Limitation on scope of design:*** N/A

6. ***Evaluation:*** The issuer's other certifying officer(s) and I have

   (a) evaluated, or caused to be evaluated under our supervision, the effectiveness of the issuer's DC&P at the financial year end and the issuer has disclosed in its annual MD&A our conclusions about the effectiveness of DC&P at the financial year end based on that evaluation; and
   (b) evaluated, or caused to be evaluated under our supervision, the effectiveness of the issuer's ICFR at the financial year end and the issuer has disclosed in its annual MD&A
      (i) our conclusions about the effectiveness of ICFR at the financial year end based on that evaluation; and
      (ii) N/A

7. ***Reporting changes in ICFR:*** The issuer has disclosed in its annual MD&A any change in the issuer's ICFR that occurred during the period beginning on *October 1, 2017 and ended on December 31, 2017* that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

8. ***Reporting to the issuer's auditors and board of directors or audit committee:*** The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of ICFR, to the issuer's auditors, and the board of directors or the audit committee of the board of directors any fraud that involves management or other employees who have a significant role in the issuer's ICFR.

Date: **March 1, 2018**

(Signed "Curtis Hicks")
Curtis Hicks, Executive Vice President & Chief Financial Officer