FOR THE YEAR ENDED DECEMBER 31, 2016

DATED FEBRUARY 24, 2017

ANNUAL INFORMATION FORM

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

INTERNATIONALLY DIVERSIFIED | SUSTAINABLE GROWTH AND INCOME

VERMILION ENERGY

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GLOSSARY OF TERMS

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

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

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

"AGCA" means Alberta Gas Cost Allowance;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"NYSE" means New York Stock Exchange;

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

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

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

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

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

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

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

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

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

"TSX" means the Toronto Stock Exchange;

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

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

"Unitholders" means former unitholders of the Trust;

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

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

Conventions

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

Abbreviations

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

Conversion

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

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

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

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

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

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

- the ability of the Company to obtain equipment, services and supplies in a timely manner to carry out its activities in Canada and internationally;
- the ability of the Company to market crude oil, natural gas liquids and natural gas successfully to current and new customers;
- the timing and costs of pipeline and storage facility construction and expansion and the ability to secure adequate product transportation;
- the timely receipt of required regulatory approvals;
- the ability of the Company to obtain financing on acceptable terms;
- foreign currency exchange rates and interest rates;
- future crude oil, natural gas liquids and natural gas prices; and
- Management's expectations relating to the timing and results of development activities.

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

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

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

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

All oil and natural gas reserve information contained in this annual information form is derived from the GLJ Report and has been prepared and presented in accordance with the *Canadian Oil and Gas Evaluation Handbook* ("COGEH") and *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this annual information form. The estimated future net revenue from the production of the disclosed oil and natural gas reserves does not represent the fair market value of these reserves.

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

Contingent Resources

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

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

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

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

Prospective Resources

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

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

NON-GAAP MEASURES

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

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

VERMILION ENERGY INC.

General

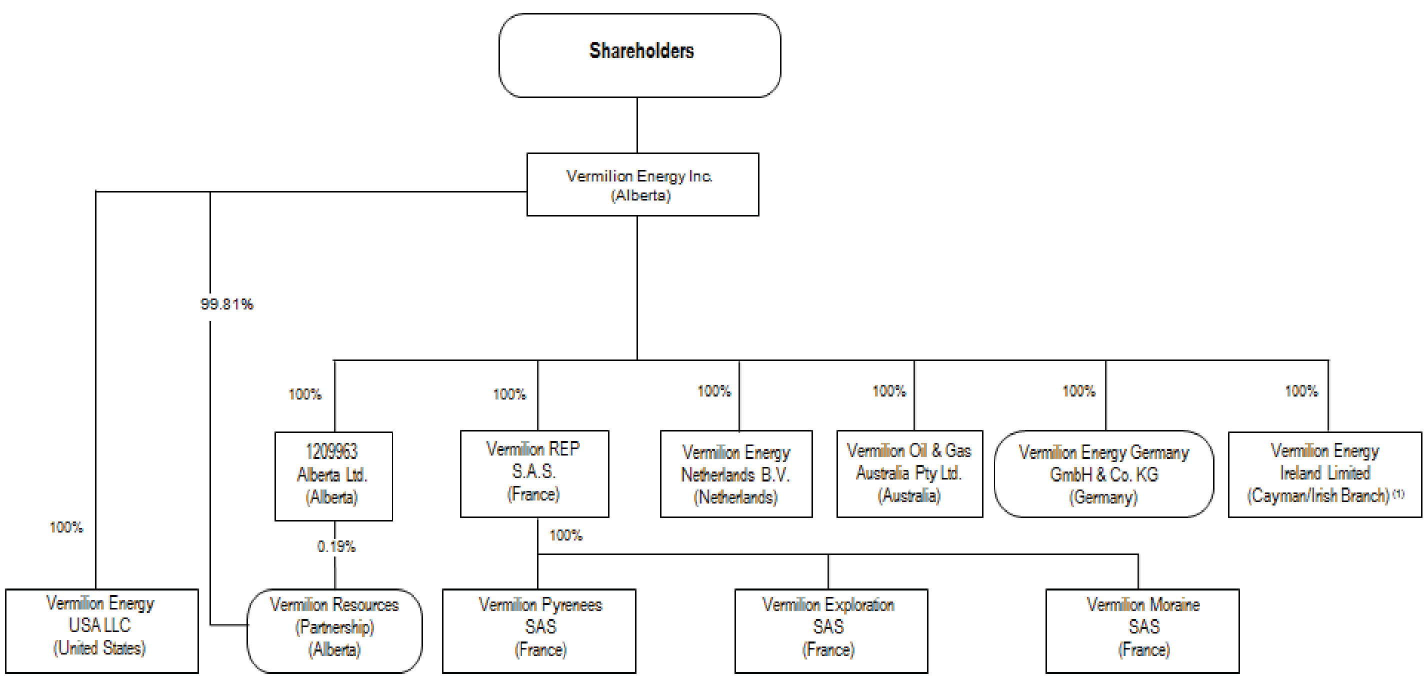
Vermilion Energy Inc. is the successor to the Trust, following the completion of the Conversion Arrangement whereby the Trust converted from an income trust to a corporate structure by way of a court approved plan of arrangement under the ABCA on September 1, 2010.

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

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

Organizational Structure of the Company

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



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

DESCRIPTION OF THE BUSINESS

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

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

Operating Segments and Description of Properties[(1)]

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

Canada Business Unit

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

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

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

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

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

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

France Business Unit

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

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

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

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

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

Netherlands Business Unit

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

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

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

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

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

Germany Business Unit

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

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

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

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

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

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

Ireland Business Unit

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

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

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

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

Australia Business Unit

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

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

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

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

United States Business Unit

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

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

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

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

Central and Eastern Europe (CEE) Business Unit

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

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

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

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

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History and Outlook

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

2014

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

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

New Area Entries

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

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

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

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

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

Crude Oil Price Decline

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

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

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

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

Other Events

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

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

2015

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

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

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

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

2016

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

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

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

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

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

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

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

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

Outlook

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

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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, 2016 with an effective date of December 31, 2016. Pricing used in the forecast price evaluations is set forth in the notes to the tables.

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

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

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

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

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

The following tables may not total due to rounding.

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

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

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

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

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

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

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

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

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

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

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

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
Total Probable	284	267	4,677	4,395	13,730	10,411	114,307	100,534
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Plus Probable [3] [4]								
Australia	17,068	17,068	-	-	-	-	-	-
Canada	36,065	31,606	-	-	14	9	368,805	330,682
France	63,977	58,911	-	-	-	-	6,374	5,978
Germany	7,567	7,411	-	-	-	-	95,764	84,299
Ireland	-	-	-	-	-	-	150,362	150,362
Netherlands	-	-	-	-	-	-	105,534	81,346
United States	8,896	7,286	-	-	-	-	8,450	6,922
Total Proved Plus Probable	133,573	122,282	-	-	14	9	735,289	659,589

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

Notes:

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

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

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

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

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

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

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

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

Net Present Value of Future Net Revenue - Based on Forecast Prices and Costs [1]

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

Notes:

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

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

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

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

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

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

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

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

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

Notes:

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

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

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

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

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

Notes:

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

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

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

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

Forecast Prices used in Estimates [(1)]

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

Note:

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

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

Reconciliations of Changes in Reserves

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Notes:

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

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

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

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

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

Undeveloped Reserves

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

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

Timing of Initial Undeveloped Reserves Assignment

Undeveloped Reserves Attributed in Current Year

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

Note:
(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year

Future Development Costs (1)

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

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

Total for all years undiscounted	60,639	137,814
Total Company		
2017	141,868	194,871
2018	159,206	237,545
2019	185,239	372,728
2020	136,105	303,472
2021	77,035	306,340
Remainder	74,804	160,181
Total for all years undiscounted	774,257	1,575,137

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

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

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

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

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

Notes:
(1) Well counts are based on wellbores.
(2) Wells for Australia and Ireland are located offshore.
(3) "Gross" refers to the total wells in which Vermilion has an interest, directly or indirectly.
(4) "Net" refers to the total wells in which Vermilion has an interest, directly or indirectly, multiplied by the percentage working interest owned by Vermilion, directly or indirectly, therein.
(5) Non-producing wells include wells which are capable of producing, but which are currently not producing, and are re-evaluated with respect to future commodity prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Costs Incurred

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

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

Acreage

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

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

Notes:
(1) "Developed" means the acreage assigned to productive wells based on applicable regulations.
(2) "Gross" means the total acreage in which Vermilion has a working interest, directly or indirectly.
(3) "Net" means the total acreage in which Vermilion has a working interest, directly or indirectly, multiplied by the percentage working interest of Vermilion.

Exploration and Development Activities

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

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

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

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

Properties with No Attributed Reserves

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

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

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

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

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

Tax Information

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

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

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

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

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

Production Estimates

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

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

Production History

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

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

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

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

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

Marketing

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

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

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

DIRECTORS AND OFFICERS

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

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

Directors

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

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

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

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

Officers

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

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

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

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

Cash Dividends

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

Record of Cash Dividends

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

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

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

Premium Dividend™ and Dividend Reinvestment Plan

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

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

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

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

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

™ denotes trademark of Canaccord Genuity Capital Corporation.

Shareholder Rights Plan

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

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

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

MARKET FOR SECURITIES

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

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

AUDIT COMMITTEE MATTERS

Audit Committee Charter

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

Composition of the Audit Committee

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

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

External Audit Service Fees

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

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

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

Notes:

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

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

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

CONFLICTS OF INTEREST

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

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

LEGAL PROCEEDINGS

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

MATERIAL CONTRACTS

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

INTERESTS OF EXPERTS

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

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

TRANSFER AGENT AND REGISTRAR

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

RISK FACTORS

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

Reserve Estimates

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

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

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

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

Uncertainty of Contingent Resource Estimates

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

Uncertainty of Prospective Resource Estimates

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

Volatility of Oil and Natural Gas Prices

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

Changes in Legislation

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

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

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

Government Regulations

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

Competition

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

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

Operational Matters

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

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

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

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

Environmental Concerns

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

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

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

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

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

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

Kyoto Protocol

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

Discretionary Nature of Dividends

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

Debt Service

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

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

Changes in Income Tax Laws

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

Depletion of Reserves

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

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

Net Asset Value

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

Volatility of Market Price of Common Shares

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

Variations in Interest Rates and Foreign Exchange Rates

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

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

Increase in Operating Costs or Decline in Production Level

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

Acquisition Assumptions

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

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

Failure to Realize Anticipated Benefits of Prior Acquisitions

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

Additional Financing

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

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

Potential Conflicts of Interest

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

Accounting Adjustments

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

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

Market Accessibility

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

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

Cyber Security

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

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

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

ADDITIONAL INFORMATION

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

APPENDIX A
CONTINGENT RESOURCES

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

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

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

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

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

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

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

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

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

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

Notes:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Charmottes	Based on contingencies related to corporate commitment and development timing, along with the project still being in the pre-development study/sourcing stage related to waterflood development, GLJ has estimated risked unclarified best estimate contingent resources at 1.3 mmboe and the risked estimated cost to bring these resources on commercial production is $29 MM. The expected timeline is 8 to 10 years.
Chaunoy	Based on contingencies related to corporate commitment and development timing, along with a CO_2 pilot project still being in the conceptual study stage, GLJ has estimated risked unclarified best estimate contingent resources at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM. The expected timeline is 9 to 10 years.

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

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

PROSPECTIVE RESOURCES

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

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

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

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

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

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

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

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

Notes:

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

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

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

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

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

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

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

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

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

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

- CoDev = Ps (Economic Factor) × Ps (Technology Factor) × Ps (Development Plan Factor) ×Ps (Development Timeframe Factor) × Ps (Other Contingency Factor) wherein
- Ps is the probability of success
- Economic Factor – For reserves to be assessed, a project must be economic. With respect to prospective resources, this factor captures uncertainty in the assessment of economic status principally due to uncertainty in cost estimates and marketing options. Economic viability uncertainty due to technology is more aptly captured with the Technology Factor. The Economic Factor will be 1 for reserves and will often be 1 for development pending and for projects with a development study or pre-development study with a robust rate of return. A robust rate of return means that the project retains economic status with variation in costs and/or marketing plans over the expected range of outcomes for these variables.
- Technology Factor - For reserves to be assessed, a project must utilize established technology. With respect to prospective resources, this factor captures the uncertainty in the viability of the proposed technology for the subject reservoir, namely, the uncertainty associated with technology under development. By definition, technology under development

is a recovery process or process improvement that has been determined to be technically viable via field test and is being field tested further to determine its economic viability in the subject reservoir. The Technology Factor will be 1 for reserves and for established technology. For technology under development, this factor will consider different risks associated with technologies being developed at the scale of the well versus the scale of a project and technologies which are being modified or extended for the subject reservoir versus new emerging technologies which have not previously been applied in any commercial application. The risk assessment will also consider the quality and sufficiency of the test data available, the ability to reliably scale such data and the ability to extrapolate results in time.

- Development Plan Factor – For reserves to be assessed, a project must have a detailed development plan. With respect to prospective resources, this factor captures the uncertainty in the project evaluation scenario. The Development Plan Factor will be 1 for reserves and high, approaching 1, for development pending projects. This factor will consider development plan detail variations including the degree of delineation, reservoir specific development and operating strategy detail (technology decision, well layouts (spacing and pad locations), completion strategy, start-up strategy, water source and disposal, other infrastructure, facility design, marketing plans etc.) and the quality of the cost estimates as provided by the developer.
- Development Timeframe Factor – In the case of major projects, for reserves to be assessed, first major capital spending must be initiated within 5 years of the effective date. The Development Timeframe Factor will be 1 for reserves and will often be 1 for development pending provided the project is planned on-stream based on the same criteria used in the assessment of reserves. With respect to prospective resources, the factor will approach 1 for projects planned on-stream with a timeframe slightly longer than the limiting reserves criteria.
- Other Contingency Factor – For reserves to be assessed, all contingencies must be eliminated. With respect to prospective resources, this factor captures major contingencies, usually beyond the control of the operator, other than those captured by economic status, technology status, project evaluation scenario status and the development timeframe. The Other Contingency Factor will be 1 for reserves and for development pending and less than 1 for on hold. Provided all contingencies have been identified and their resolution is reasonably certain, this factor would also be 1 for development unclarified.
- These factors may be inter-related (dependent) and care has been taken to ensure that risks are appropriately accounted.

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

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

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

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

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

Wilrich Prospect:	Based on reservoir risk, development timing and limited Wilrich development on the land base, GLJ has estimated the CoDev at 35% and the CoDis at 85%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 22.2 mmboe and the risked estimated cost to bring these resources on commercial production is $218 MM with an expected timeline of 2 to 8 years.
West Pembina Glauconite Prospect:	Based on chance of discovery risk due to uncertainty regarding threshold for reservoir quality to support commercial development of resources with horizontal drilling, along with economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands and chance of development risk related to corporate commitment and development timing. GLJ has estimated the CoDev at 34% and the CoDis at 90%. The corresponding chance of commerciality is 31%. Risked best estimate prospective resources have been estimated at 8.4 mmboe and the risked estimated cost to bring these resources on commercial production is $242 MM with an expected timeline of 6 to 14 years.
Drayton Valley Notikewin Prospect:	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 85%. The corresponding chance of commerciality is 60%. Risked best estimate prospective resources have been estimated at 4.6 mmboe and the risked estimated cost to bring these resources on commercial production is $69.3 MM. The expected development timeline is 10 to 12 years.

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

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

Rachee Prospect	Based on risk of closure and data quality along with development timing, GLJ has estimated the CoDev at 80% and the CoDis at 80%. The corresponding chance of commerciality is 64%. Risked best estimate prospective resources have been estimated at 3.4 mmboe and the risked estimated cost to bring these resources on commercial production is $125.0 MM with an expected timeline of 10 to 14 years.
Malnoue Prospect	Based on reservoir, structure and trap risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 38%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $31.6 MM with an expected timeline of 8 to 12 years.
West Lavergne Prospect	Based on structure risk and development timing GLJ has estimated the CoDev at 80% and the CoDis at 70%. The corresponding chance of commerciality is 56%. Risked best estimate prospective resources have been estimated at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $6.1 MM with an expected timeline of 4 years.
Champotran Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 80% and the CoDis at 80%. The corresponding chance of commerciality is 64%. Risked best estimate prospective resources have been estimated at 0.7 mmboe and the risked estimated cost to bring these resources on commercial production is $14.6 MM with an expected timeline of 7 to 8 years.
Cazaux Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 30%. The corresponding chance of commerciality is 21%. Risked best estimate prospective resources have been estimated at 0.6 mmboe and the risked estimated cost to bring these resources on commercial production is $10.3 MM with an expected timeline of 5 to 7 years.
Vulaines Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 80% and the CoDis at 40%. The corresponding chance of commerciality is 32%. Risked best estimate prospective resources have been estimated at 0.6 mmboe and the risked estimated cost to bring these resources on commercial production is $12.6 MM with an expected timeline of 5 to 6 years.
Phobos Prospect	Based on reservoir, and closure risk, economic factors and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 50%. The corresponding chance of commerciality is 25%. Risked best estimate prospective resources have been estimated at 0.5 mmboe and the risked estimated cost to bring these resources on commercial production is $20.6 MM with an expected timeline of 9 to 10 years.
Charmottes Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 50%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 0.5 mmboe and the risked estimated cost to bring these resources on commercial production is $18.5 MM with an expected timeline of 8 to 10 years.
Bernet Prospect	Based on risks associated with reservoir, seal and trap along with economic factors, and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 65%. The corresponding chance of commerciality is 33%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $6.7 MM with an expected timeline of 5 to 6 years.
Vert Le Grand Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 28%. The corresponding chance of commerciality is 20%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $3.6 MM with an expected timeline of 3 years.
Pays De Born Prospect	Based on reservoir, seal and trap risk, along with economic factors and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 50%. The corresponding chance of commerciality is 25%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $2.6 MM with an expected timeline of 8 to 9 years.
Les Genets Prospect	Based on reservoir, seal and closure risk, along with economic factors and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 16%. The corresponding chance of commerciality is 9.6%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $0.9 MM with an expected timeline of 9 years.
North Acacias Prospect	Based on reservoir, seal and trap risk, along with economic factors and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 39%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 0.08 mmboe and the risked estimated cost to bring these resources on commercial production is $1.2 MM with an expected timeline of 6 to 7 years.

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

Ihlow Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 71%, and the CoDis at 51%. The corresponding chance of commerciality is 36%. Risked best estimate prospective resources have been estimated at 6.6 mmboe and the risked estimated cost to bring these resources on commercial production is $44.7 MM with an expected timeline of 8 years.
Wisselshorst A Prospect	Based on seal and trap risk along with development timing , GLJ has estimated the CoDev at 90%, and the CoDis at 45%. The corresponding chance of commerciality is 41%. Risked best estimate prospective resources have been estimated at 4.8 mmboe and the risked estimated cost to bring these resources on commercial production is $32.2 MM with an expected timeline of 8 years.
Simonswolde South Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 71%, and the CoDis at 48%. The corresponding chance of commerciality is 34%. Risked best estimate prospective resources have been estimated at 4.1 mmboe and the risked estimated cost to bring these resources on commercial production is $14.6 MM with an expected timeline of 10 years.
Klosterseelte Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 49%, and the CoDis at 49%. The corresponding chance of commerciality is 24%. Risked best estimate prospective resources have been estimated at 2.8 mmboe and the risked estimated cost to bring these resources on commercial production is $12.2 MM with an expected timeline of 5 years.
Ohlendorf Prospect	Based on source and trap risk along with development timing, GLJ has estimated the CoDev at 58%, and the CoDis at 30%. The corresponding chance of commerciality is 17%. Risked best estimate prospective resources have been estimated at 2.4 mmboe and the risked estimated cost to bring these resources on commercial production is $10.1 MM with an expected timeline of 15 years.
Wisselshorst B Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 90%, and the CoDis at 38%. The corresponding chance of commerciality is 34%. Risked best estimate prospective resources have been estimated at 2.3 mmboe and the risked estimated cost to bring these resources on commercial production is $17.9 MM with an expected timeline of 11 years.
Jeddeloh Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 38%, and the CoDis at 31%. The corresponding chance of commerciality is 12%. Risked best estimate prospective resources have been estimated at 2.3 mmboe and the risked estimated cost to bring these resources on commercial production is $18.5 MM with an expected timeline of 8 years.
Simonswolde North Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 62%, and the CoDis at 45%. The corresponding chance of commerciality is 28%. Risked best estimate prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $5.6 MM with an expected timeline of 8 years.
Uphuser Meer Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 47%, and the CoDis at 51%. The corresponding chance of commerciality is 24%. Risked best estimate prospective resources have been estimated at 1.0 mmboe and the risked estimated cost to bring these resources on commercial production is $4.5 MM with an expected timeline of 9 years.
Burgmoor Z5 Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 63%, and the CoDis at 52%. The corresponding chance of commerciality is 33%. Risked best estimate prospective resources have been estimated at 0.7 mmboe and the risked estimated cost to bring these resources on commercial production is $2.8 MM with an expected timeline of 2 years.
Wellie Prospect	Based on reservoir, seal and source risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDis at 20%. The corresponding chance of commerciality is 6%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3 MM with an expected timeline of 11 years.
Otterstedt Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 46%, and the CoDis at 34%. The corresponding chance of commerciality is 16%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3.2 MM with an expected timeline of 14 years..
Widdernhausen East Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDis at 44%. The corresponding chance of commerciality is 14%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $2.1 MM with an expected timeline of 12 years.
Ostervesede Prospect	Based on reservoir and seal risk along with development timing, GLJ has estimated the CoDev at 23%, and the CoDis at 25%. The corresponding chance of commerciality is 6%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $0.7 MM with an expected timeline of 11years.

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

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

- Chance of discovery provided for 111 prospective reservoir targets across 92 prospective locations. Risk primarily associated with presence of reservoir and seal as region proven to have adequate source, migration and timing to charge target reservoirs.
- Chance of development risked to account for company commitment and development timing, anticipated timing for permitting in respective licenses and distance to export (i.e. pipeline/facility requirements to transport gas to sales point). Chance of development is also a function of prospect size.

- 92 prospects summed probabilistically across 13 development groups to appropriately allocate required infrastructure capital across multiple prospective targets within reasonable proximity. As probabilistic summation of the groups resulted in strong economic indicators, no further minimum economic field size calculations were applied as they were considered to have nominal impact.

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

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

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

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

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

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

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

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

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

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

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

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

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

EXECUTED as to our reports referred to above:

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

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

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, 2016. The contingent resources data and prospective resources data are risked estimates of volume of contingent resources and prospective resources and related risked net present value of future net revenue as at December 31, 2016, estimated using forecast prices and costs.

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

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

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

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

Contingent Resources

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

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

Prospective Resources

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

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

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

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

EXECUTED as to our reports referred to above:

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

"*Jodi L. Anhorn*"

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

GLJ PETROLEUM CONSULTANTS

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

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

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

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

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

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

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

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

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

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

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

(c) the content and filing of this report.

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

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

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

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

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

February 24, 2017

APPENDIX D
TERMS OF REFERENCE FOR THE AUDIT COMMITTEE

I. PURPOSE

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

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

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

C. the independent auditors' qualifications and independence;

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

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

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

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

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

II. COMPOSITION AND OPERATIONS

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

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

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

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

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

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

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

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

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

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

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

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

III. DUTIES AND RESPONSIBILITIES

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

A. Financial Statements and Other Financial Information

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

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

Review, and where appropriate, discuss:

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

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

B. Risk Management, Internal Control and Information Systems

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

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

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

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

C. External Audit

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

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

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

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

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

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

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

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

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

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

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

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

D. Compliance

The Committee shall:

i) Ensure that the external auditor's fees are disclosed by category in the Annual Information Form in compliance with regulatory requirements;

ii) Disclose any specific policies or procedures adopted for pre-approving non-audit services by the external auditor including affirmation that they meet regulatory requirements;

iii) Assist the Governance and Human Resources Committee with preparing the Company's governance disclosure by ensuring it has current and accurate information on:
   a) the independence of each Committee member relative to regulatory requirements for audit committees;
   b) the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status; and
   c) the education and experience of each Committee member relevant to his or her responsibilities as Committee member.

iv) Disclose, if required, if the Company has relied upon any exemptions to the requirements for committees under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading.

E. Other

The Committee shall:

i) establish and periodically review procedures for:
   a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and
   b) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other matters that could negatively affect the Company, such as violations of the Code of Business Conduct and Ethics.

ii) review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor;

iii) review insurance coverage of significant business risks and uncertainties;

iv) review material litigation and its impact on financial reporting;

v) review policies and procedures for the review and approval of officers' expenses and perquisites;

vi) review the policies and practices concerning the expenses and perquisites of the Chairman, including the use of the assets of the Company;

vii) review with external auditors any corporate transactions in which directors or officers of the Company have a personal interest; and

viii) review the terms of reference for the Committee at least annually and otherwise as it deems appropriate, and recommend changes to the Board as required. The Committee shall evaluate its performance with reference to the terms of reference annually.

IV. ACCOUNTABILITY

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

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

EXCELLENCE

We aim for exceptional results in everything we do.

TRUST

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

RESPECT

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

RESPONSIBILITY

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

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

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

vermilionenergy.com