FOR THE YEAR ENDED DECEMBER 31, 2018

ANNUAL INFORMATION FORM

EXCELLENCE. TRUST. RESPECT. RESPONSIBILITY.

DATED FEBRUARY 27, 2019

VERMILION ENERGY

Front Cover Theme

Sustainability is integrated into every facet of Vermilion's business. This 15-hectare greenhouse is an example of how Vermilion reduces greenhouse emissions with geothermal energy. At Vermilion's production facility in Parentis-en-Born, France, heat from our produced water is transferred to the heating system of the adjacent greenhouse. The result is an economically and ecologically viable greenhouse operation growing tomatoes with heat generated without carbon emissions.

Across the company, Vermilion has decreased our emissions intensity on a per unit of production basis. This is due to our energy efficiency programs, emission reduction initiatives and an operational structure that maximizes production while reducing our footprint and energy consumption intensity.

Read more about Vermilion's renewable energy projects in our Sustainability Report online at www.vermilionenergy.com.

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Glossary

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

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

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

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

"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.

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

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

"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 7, 2019 and effective December 31, 2018.

"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, 2018.

"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.

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

"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.

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

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

"Unitholders" means former unitholders of the Trust.

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

Conventions

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

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, 2018, based on forecast costs and price assumptions as evaluated in the GLJ Report.

Abbreviations

bbl	barrel
Mbbl	thousand barrels
bbl/d	barrels per day
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
°API	An indication of the specific gravity of crude oil measured on the API (American Petroleum Institute) gravity scale.
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 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 at the National Balancing Point Virtual Trading Point operated by National Grid
AECO	the daily average benchmark price for natural gas at the AECO ‘C’ hub in southeast Alberta

Conversions

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

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

Special Note Regarding Forward Looking Statements

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

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

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

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

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

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

- other risks and uncertainties described elsewhere in this annual information form or in the Company's other filings with Canadian securities authorities.

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

Presentation of Oil and Gas Information

Oil and gas reserves and production

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 estimated 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.

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 estimated net present value of the future net revenue from the prospective resources does not 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 AIF includes references to certain financial and performance measures which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS"). These measures include:

- Fund flows from operations: Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 “Operating Segments”. Please see "Segmented information" in the "Notes to the consolidated financial statements" for a reconciliation of fund flows from operations to net earnings. Vermilion analyzes fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to the Company's ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Netbacks: Netbacks are per boe and per mcf performance measures used in the analysis of operational activities. Vermilion assesses netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and also versus third party crude oil and natural gas producers.

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

- Cash dividends per share: Represents actual cash dividends paid per share by the Company during the relevant periods.
- Capital expenditures: Represents the sum of drilling and development and exploration and evaluation. Vermilion considers capital expenditures to be a useful measure of its investment in the Company's existing asset base. Capital expenditures are also referred to as E&D capital.

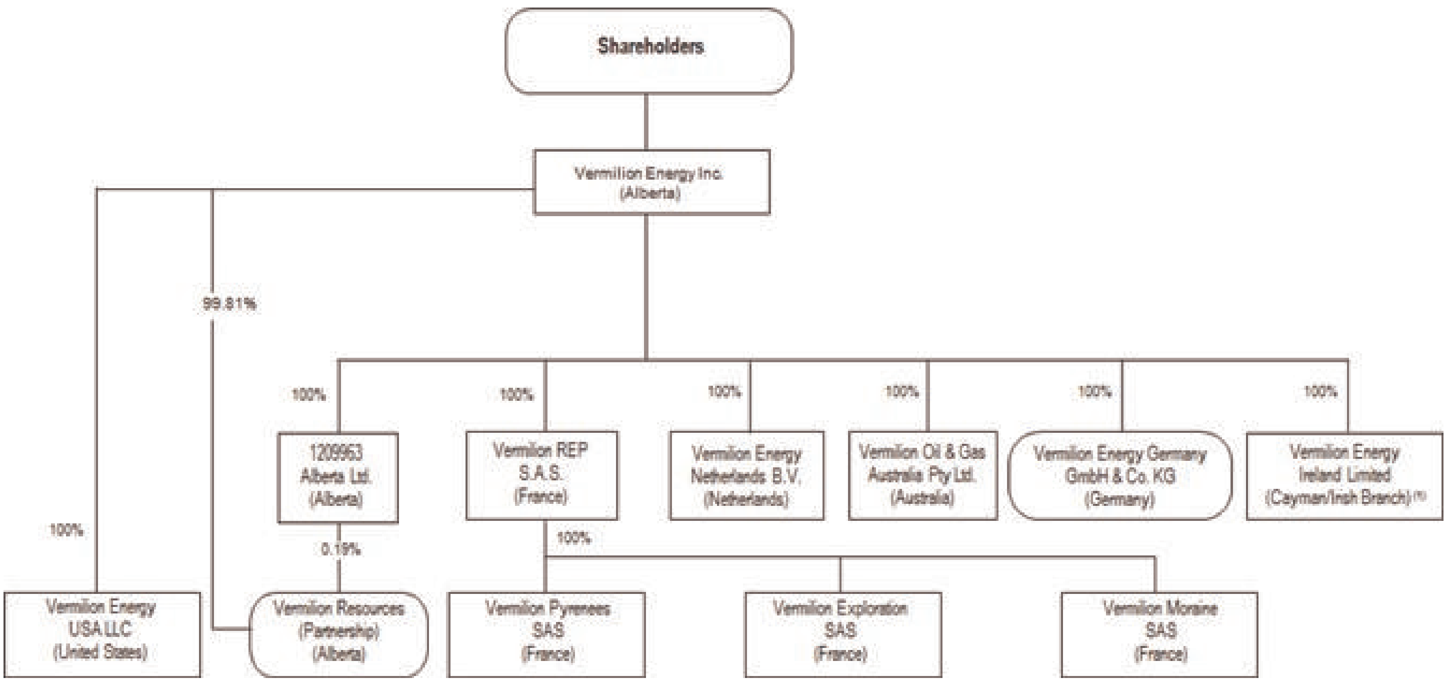
Vermilion's Organizational Structure

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, 2018, Vermilion had 698 full time employees of which 225 employees were located in its Calgary head office, 92 employees in its Canadian field offices, 152 employees in France, 60 employees in the Netherlands, 32 employees in Australia, 21 employees in the United States, 29 employees in Germany, 5 employees in Hungary, 3 employees in Croatia and 79 employees in Ireland.

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

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 AIF 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 a 20% 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 (formerly the Carbon Disclosure Project), and a Best Workplace in the Great Place to Work® Institute's annual rankings in Canada, the Netherlands and Germany. Vermilion emphasizes strategic community investment in each of our operating areas.

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 business units and the material oil and natural gas properties, facilities and installations in which Vermilion has an interest are discussed below.

The following table summarizes production, sales, proved reserves, and proved plus probable reserves for each of Vermilion's business units as at and for the year ended December 31, 2018.

Business Unit	Production (boe/d)	Oil sales ($ millions)	NGL sales ($ millions)	Natural gas sales ($ millions)	Sales ($ million)	Gross Proved Reserves (Mboe)[1]	Gross Proved Plus Probable Reserves (Mboe)[1]
Canada	48,630	541,844	56,554	72,774	671,172	181,664	284,476
France	11,396	360,471	—	131	360,602	43,466	63,918
Netherlands	7,779	2,462	—	163,454	165,916	11,802	22,196
Germany	3,614	32,704	—	49,745	82,449	12,991	25,735
Ireland	9,195	—	—	205,150	205,150	13,093	20,575
Australia	4,494	150,733	—	—	150,733	9,668	14,480
United States	1,992	31,142	4,622	2,701	38,465	25,147	56,214
Central and Eastern Europe	169	—	—	3,630	3,630	131	191
Total	87,270	1,119,356	61,176	497,585	1,678,117	297,962	487,785

(1) "Gross Reserves" are Vermilion's working interest (operating or non-operating) share before deduction of royalty obligations and without including any royalty interests of Vermilion.

Canada Business Unit

Vermilion's Canadian production is primarily focused in the West Pembina region of West Central Alberta and in southeast Saskatchewan and Manitoba. Vermilion's main targets in West Pembina are the condensate-rich Mannville and Cardium light oil plays, while our light oil targets in southeast Saskatchewan and Manitoba are the Mississippian Midale, Frobisher/Alida and Ratcliffe formations. West Pembina is the Company's main NGL producing area.

Vermilion holds an average 80% working interest in approximately 680,300 (544,500 net) acres of developed land, and an average 87% working interest in approximately 504,900 (439,800 net) acres of undeveloped land. Vermilion had 554 (397 net) producing natural gas wells and 5,272 (3,346 net) producing oil wells in Canada as at December 31, 2018.

Vermilion has access to ample facilities and processing capacity across the major plays in our Canadian portfolio. In Alberta, our operations are very geographically focused and we own and operate the large majority of associated key infrastructure including pipelines, compressor stations, oil batteries and gas plants, many of which have surplus capacity for our planned production. Furthermore, we are interconnected in several locations with third party midstream infrastructure that provides significant room for growth. In Saskatchewan, where our operations are oil focused, we own and operate extensive pipeline networks and oil batteries in each of our field areas that also have surplus capacity for our planned production. The significant degree of operating control and the coverage of our land base by key infrastructure in all of our Canadian regions allows us to drive operating efficiencies in the field and supports our growth profile.

In May 2018, Vermilion acquired Spartan Energy Corp. ("Spartan") representing the largest corporate acquisition in the Company's history. Consideration consisted of the issuance of 27.9 million Vermilion common shares valued at approximately $1.2 billion (based on the closing price per Vermilion common share of $44.30 on the Toronto Stock Exchange on May 28, 2018). Vermilion also assumed approximately $172 million of Spartan's outstanding debt at the time the transaction closed. The acquisition added over 400,000 net acres to our southeast Saskatchewan land base.

During 2018 Vermilion drilled or participated in 23 (20.7 net) Mannville wells and four (2.7 net) Cardium wells in Alberta and 146 (112.8 net) wells in southeast Saskatchewan, 126 (92.6 net) of which were drilled on the Spartan assets. In 2019, we plan to drill or participate in 143 (129.0 net) light oil wells in Saskatchewan and 20 (17.7 net) wells in Alberta including 19 (16.7 net) Mannville wells. This will mark our most active capital program ever in Canada as we focus on our first full year operating the former Spartan assets.

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 19 oil batteries and 15 single well batteries in the country. Given the legacy nature of these assets, the throughput capability of these batteries exceeds any projected future requirements. Vermilion holds an average 96% working interest in 258,100 (248,900 net) acres of developed land and 92% working interest in 274,000 (251,800 net) acres of undeveloped land in the Aquitaine and Paris Basins. Vermilion had 344 (337 net) producing oil wells and two (2.0 net) producing gas wells in France as at December 31, 2018.

In 2018, Vermilion drilled two (2.0 net) wells in the Neocomian field in the Paris basin and three (3.0 net) wells in the Champotran field. In 2019, Vermilion intends to drill four (4.0 net) Champotran wells. The Company also intends to continue its ongoing program of workovers and optimizations. By continuing to develop its inventory in France, while minimizing declines through workovers and optimizations, Vermilion seeks to deliver moderate production growth from its French assets.

Netherlands Business Unit

Vermilion entered the Netherlands in 2004 and is the country's second largest onshore natural gas producer (excluding state-owned energy company EBN). Vermilion's natural gas production in the Netherlands is priced off of the TTF index.

Vermilion's Netherlands assets consist of 26 onshore concessions (all operated) and 17 offshore concessions (all non-operated). Production consists primarily of natural gas with a small amount of related condensate. Vermilion’s total land position in the Netherlands covers 1,927,300 (930,000 net) acres at an average 48% working interest, of which 90% is undeveloped. Vermilion had 114 (103 net) producing natural gas wells as at December 31, 2018.

Vermilion brought on production the previously drilled and tested Eesveen-02 well (60% working interest) in the Netherlands during 2018 and the Company expects to drill two (1.0 net) exploration wells in 2019. 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.

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 based on the NCG and GPL indexes, which are both highly correlated to the TTF benchmark, and Vermilion's 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 eight oil fields. Prior to the December 2016 acquisition, Vermilion's producing assets in Germany consisted of a 25% non-operated interest in four natural gas fields. Vermilion had 133 (105 net) producing oil wells and 21 (8 net) producing natural gas wells as at December 31, 2018.

Vermilion holds a significant land position in northwest Germany comprised of 88,600 (32,600 net) developed acres and 2,815,400 (1,149,400 net) undeveloped acres. The Company also holds a 0.4% equity interest in Erdgas Munster GmbH ("EGM"), a joint venture created in 1959 to jointly transport, process, and market gas in northwest Germany. This transportation interest allows for our proportionate share of produced volumes to be processed, blended, and transported to designated gas consumers through the EGM network of approximately 2,000 kilometres of pipeline. Furthermore, the Company holds a 50% equity interest in Hannoversche Erdölleitung GmbH ("HEG"), a joint venture company created in 1959 that collects and transports oil through a 185 km network of infrastructure from the Hannover region to rail loading facilities in Hannover.

During 2018, Vermilion focused on permitting and other pre-drill activities associated with our first operated well in Germany, Burgmoor Z5 (46% working interest) in the Dümmersee-Uchte area, along with other workover and optimization opportunities. In 2019, the Company plans to drill the Burgmoor Z5 well and continue to invest in optimization and other well work. Vermilion will also advance permitting, studies and other activities associated with the farm-in agreement signed in mid-2015.

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 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 plateaued at this level until decline started at the beginning of 2018.

In July 2017, Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership in Corrib, whereby CPPIB acquired Shell E&P Ireland Limited's 45% interest in Corrib. At closing, Vermilion assumed operatorship of Corrib and CPPIB transferred a 1.5% working interest to Vermilion, bringing our ownership interest in Corrib to 20%. The acquisition has an effective date of January 1, 2017 and closed in December 2018.

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).

During 2018, Vermilion drilled two (2.0 net) wells in Australia and does not presently expect to drill any additional Australian wells until approximately 2021. Vermilion intends to manage its Australian asset and related capital investment programs to maintain stable production levels of approximately 6,000 bbl/d.

United States Business Unit

Vermilion entered the United States in 2014 in the East Finn oil field of northeastern Wyoming and expanded its position through the 2018 acquisition of mineral land and producing assets in the Hilight oil field located approximately 40 miles northwest of the existing assets. The Company's assets include 165,100 (148,700 net) acres of land in the Powder River basin, of which 71% is undeveloped. Vermilion had 127 (118 net) producing oil wells in the United States as at December 31, 2018. All of our working interest ownership in Wyoming is Company operated.

During 2018, Vermilion continued work on its early stage Turner Sand development in the Powder River Basin, drilling and completing five (5.0 net) wells on our East Finn asset and one (1.0 net) well on our recently acquired Hilight asset. In 2019, Vermilion expects to drill six (6.0 net) wells on our Hilight asset and another two (2.0 net) wells on our East Finn asset.

Central and Eastern Europe ("CEE") Business Unit

Vermilion established a CEE Business unit in 2014 with a head office in Budapest, Hungary. The CEE business unit is responsible for business development in the CEE, including managing the exploration and development opportunities associated with the Company's land holdings in Hungary, Slovakia and Croatia.

Vermilion's land position in the CEE consists of 652,800 (652,800 net) acres in Hungary, 485,000 (242,500 net) acres in Slovakia and 2.35 million (2.35 million net) acres in Croatia. Currently, 99% of Vermilion's land position in the CEE is undeveloped.

Vermilion drilled its first well (1.0 net) in the CEE in the South Battonya license of Hungary in 2018. In 2019, Vermilion plans to drill three (2.5 net) net wells in Hungary, four (2.0 net) wells in Slovakia, and three (2.5 net) wells in Croatia, representing a notable increase in activity in the business unit from prior years.

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.

With the exception of the acquisition of Spartan in May 2018, none of the acquisitions described below constituted a “significant acquisition” within the meaning of applicable securities laws. A Business Acquisition Report (Form 51-102F4) relating to the acquisition of Spartan was filed on July 30, 2018 and is incorporated by reference in this AIF. A copy of this report is available on SEDAR at www.sedar.com under Vermilion’s SEDAR profile.

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 was 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. Accordingly, in January 2016, Vermilion announced a $285 million E&D capital budget for 2016 representing a 42% decrease from 2015. As commodity prices continued to weaken during Q1 2016, in February 2016 Vermilion announced a further reduction in its 2016 E&D capital budget to $235 million. In August 2016, Vermilion modestly increased its E&D capital expenditure guidance for 2016 to $240 million. E&D capital expenditures for 2016 totaled $242.4 million, representing decreases from 2015 and 2014 of 50% and 65%, respectively.

Vermilion maintained its monthly dividend at $0.215 per share during the year. Commencing with the October 2016 dividend payment, the Company began prorating the Premium Dividend™ Component of the Dividend Reinvestment Plan (implemented in February 2015) 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.

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

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

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

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

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

2017

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

Vermilion maintained its monthly dividend at $0.215 per share throughout 2017. As the Company's business continued its strong performance and with the prospect of a more stable commodity price environment, Vermilion discontinued the Premium Dividend™ Component of its dividend reinvestment plan beginning with the July 2017 dividend payment.

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

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

In July 2017, Vermilion and Canada Pension Plan Investment Board ("CPPIB") announced a strategic partnership in the Corrib Natural Gas Project in Ireland (Corrib), whereby CPPIB will acquire Shell E&P Ireland Limited’s 45% interest in Corrib. As part of the transaction, Vermilion assumed operatorship of Corrib and an additional 1.5% working interest in Corrib. The acquisition had an effective date of January 1, 2017 and closed in late 2018.

In December 2017, Vermilion was awarded a license for the Békéssámson concession in Hungary for a 4-year term. Located adjacent to the existing South Battonya concession in southeast Hungary, the Békéssámson concession covers 330,700 net acres (100% working interest) and more than doubled the size of the Company's total land position in the country.

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

2018

Vermilion achieved record annual production of 87,270 boe/d representing an increase of 28% as compared to 2017. Production in Canada reached record levels as the Company completed the most significant corporate acquisition in its history, acquiring Spartan in May 2018 for total consideration of $1.4 billion. Production also grew in the US due to an acquisition completed in August 2018 near Vermilion's existing assets in the Powder River Basin.

Vermilion increased its monthly dividend to $0.23 per share from $0.215 per share beginning with the April 2018 dividend. Upon closing the acquisition of Spartan, the 2% discount associated with our Dividend Reinvestment Plan was eliminated, beginning with the June 2018 dividend.

In February 2018, Vermilion closed an acquisition of a private southeast Saskatchewan producer. The acquisition added over 1,000 bbl/d of high netback 40° API oil and 42,600 net acres of land straddling the Saskatchewan and Manitoba border, near Vermilion's existing operations in southeast Saskatchewan. Total consideration of $91 million, which includes both cash paid to the shareholders of the acquired company and the assumption of long-term debt, was funded through the Company's revolving credit facility.

In May 2018, Vermilion acquired all of the issued and outstanding common shares of Spartan, a publicly traded southeast Saskatchewan oil producer. Total consideration for the acquisition was $1.4 billion consisting of the issuance of 27.9 million Vermilion common shares valued at approximately $1.2 billion (based on the closing price per Vermilion common share of $44.30 on the Toronto Stock Exchange on May 28, 2018) and the assumption of approximately $175 million of Spartan's outstanding debt at the time the transaction closed.

In August 2018, Vermilion acquired mineral land and producing assets in the Powder River Basin in Wyoming for total cash consideration of approximately $189 million. The acquisition is comprised of low base decline, light oil-weighted production and high-quality mineral leasehold in the Powder River Basin in Campbell County, Wyoming, approximately 40 miles (65 kilometres) northwest of Vermilion's existing operations. The Assets include approximately 55,700 net acres of land (approximately 96% working interest) and approximately 2,500 boe/d (63% oil and NGLs) of production with an estimated annual base decline rate of 13%. Approximately half of the current production comes from three federal secondary recovery units in the Muddy formation, with the remainder coming from higher netback production from Turner Sand horizontal producers.

In December 2018, Vermilion closed our acquisition of an additional 1.5% working interest in Corrib bringing the Company's ownership interest in the project to 20%. Vermilion also assumed operatorship of Corrib resulting in a significant increase in the degree of operating control across the Company's portfolio.

Vermilion received a top quartile ranking for its industry sector in RobecoSAM's annual Corporate Sustainability Assessment. The CSA analyzes sustainability performance across economic, environmental, governance and social criteria, and is the basis of the Dow Jones Sustainability Indices. Vermilion was ranked 11th by Corporate Knights on the Future 40 Responsible Corporate Leaders in Canada list. This marks the fifth year in a row that Vermilion has been recognized by Corporate Knights as one of Canada's top sustainability performers and we continue to be the highest ranked oil and gas company on the list. Vermilion's MSCI ESG (Environment, Social and Governance) received an A rating for the second consecutive year and the Company's Governance Metrics score ranked in the top decile globally. Vermilion scored an 82 out of 100 on the annual ratings conducted by Sustainalytics, ranking at the top of its peer group. Sustainalytics rates the sustainability of participating companies based on their environmental, social and governance performance.

Further demonstrating Vermilion's commitment to being a leader in environmental, social and governance practices, the Board of Directors has established a Sustainability Committee to provide oversight with respect to sustainability policy and performance. Members of the committee are Tim Marchant (Chair), Carin Knickel, Steve Larke and Bill Roby, each an independent director.

Outlook

Vermilion's business model continues to allow for flexibility in response to volatile commodity prices and regulatory changes. The Company intends to maintain a low level of financial leverage and continue to fund dividends and E&D capital investment from internally generated fund flows from operations. Consistent with these objectives, in October 2018 Vermilion announced an E&D capital budget for 2019 of $530 million with corresponding production guidance of between 101,000 to 106,000 boe/d. The 2019 program reflects a full year of development on the Spartan assets, additional capital associated with the recently acquired assets in the Powder River Basin, and also incorporates a significantly expanded drilling program in Europe.

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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 7, 2019 with an effective date of December 31, 2018. 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, 2018 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 are established using deterministic methodology. Total proved reserves are established at the 90 percent probability (P90) level. There is a 90 percent probability that the actual reserves recovered will be equal to or greater than the P90 reserves. Total proved plus probable reserves are established at the 50 percent probability (P50) level. There is a 50 percent probability that the actual reserves recovered will be equal to or greater than the P50 reserves.

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

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

The following tables may not total due to rounding.

Oil and gas reserves - Based on forecast prices and costs [1]

	Light & Medium Crude Oil (Mbbl)			Heavy Oil (Mbbl)			Tight Oil (Mbbl)			Conventional Natural Gas (MMcf)		
Proved Developed Producing [3] [5] [6]	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**
Australia	8,048	8,048	8,048	—	—	—	—	—	—	—	—	—
Canada	53,791	53,646	48,190	22	22	19	—	—	—	192,567	192,162	178,329
France	36,519	36,519	33,145	—	—	—	—	—	—	6,464	6,464	5,899
Germany	4,401	4,401	4,287	—	—	—	—	—	—	32,870	32,870	28,047
Hungary	—	—	—	—	—	—	—	—	—	788	788	630
Ireland	—	—	—	—	—	—	—	—	—	78,560	78,560	78,560
Netherlands	—	—	—	—	—	—	—	—	—	45,003	45,003	44,536
United States	3,751	3,751	3,120	—	—	—	—	—	—	29,335	29,335	24,438
Total Proved Developed Producing	**106,510**	**106,365**	**96,790**	**22**	**22**	**19**	**—**	**—**	**—**	**385,587**	**385,182**	**360,439**

	Shale Gas (MMcf)			Coal Bed Methane (MMcf)			Natural Gas Liquids (Mbbl)			BOE (Mboe)		
Proved Developed Producing [3] [5] [6]	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**
Australia	—	—	—	—	—	—	—	—	—	8,048	8,048	8,048
Canada	906	906	860	629	629	587	17,829	17,787	14,714	103,992	103,738	92,886
France	—	—	—	—	—	—	—	—	—	37,596	37,596	34,128
Germany	—	—	—	—	—	—	—	—	—	9,879	9,879	8,962
Hungary	—	—	—	—	—	—	—	—	—	131	131	105
Ireland	—	—	—	—	—	—	—	—	—	13,093	13,093	13,093
Netherlands	—	—	—	—	—	—	128	128	127	7,629	7,629	7,550
United States	—	—	—	—	—	—	3,065	3,065	2,553	11,705	11,705	9,746
Total Proved Developed Producing	**906**	**906**	**860**	**629**	**629**	**587**	**21,022**	**20,980**	**17,394**	**192,073**	**191,819**	**174,518**

	Light & Medium Crude Oil (Mbbl)			Heavy Oil (Mbbl)			Tight Oil (Mbbl)			Conventional Natural Gas (MMcf)		
Proved Developed Non-Producing [3] [5] [7]	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**
Australia	1,620	1,620	1,620	—	—	—	—	—	—	—	—	—
Canada	5,891	5,890	4,916	—	—	—	—	—	—	14,427	14,427	13,273
France	441	441	381	—	—	—	—	—	—	—	—	—
Germany	689	689	667	—	—	—	—	—	—	8,126	8,126	7,088
Hungary	—	—	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	—	—	—	20,475	20,475	20,475
United States	—	—	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	**8,641**	**8,640**	**7,584**	**—**	**—**	**—**	**—**	**—**	**—**	**43,028**	**43,028**	**40,836**

	Shale Gas (MMcf)			Coal Bed Methane (MMcf)			Natural Gas Liquids (Mbbl)			BOE (Mboe)		
Proved Developed Non-Producing [3] [5] [7]	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**	**Company Interest [2]**	**Gross [2]**	**Net [2]**
Australia	—	—	—	—	—	—	—	—	—	1,620	1,620	1,620
Canada	—	—	—	746	746	703	1,076	1,076	940	9,496	9,495	8,185
France	—	—	—	—	—	—	—	—	—	441	441	381
Germany	—	—	—	—	—	—	—	—	—	2,043	2,043	1,848
Hungary	—	—	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	56	56	56	3,469	3,469	3,469
United States	—	—	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	**—**	**—**	**—**	**746**	**746**	**703**	**1,132**	**1,132**	**996**	**17,069**	**17,068**	**15,503**

Proved Undeveloped [3] [8]	Light & Medium Crude Oil (Mbbl)			Heavy Oil (Mbbl)			Tight Oil (Mbbl)			Conventional Natural Gas (MMcf)		
	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—	—	—	—	—
Canada	35,041	35,029	30,617	78	78	67	—	—	—	111,756	111,752	101,206
France	5,419	5,419	4,861	—	—	—	—	—	—	57	57	57
Germany	648	648	633	—	—	—	—	—	—	2,523	2,523	1,919
Hungary	—	—	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	—	—	—	4,228	4,228	4,228
United States	9,238	9,238	7,633	—	—	—	—	—	—	15,370	15,370	12,766
Total Proved Undeveloped	**50,346**	**50,334**	**43,744**	**78**	**78**	**67**	**—**	**—**	**—**	**133,934**	**133,930**	**120,176**

Proved Undeveloped [3] [8]	Shale Gas (MMcf)			Coal Bed Methane (MMcf)			Natural Gas Liquids (Mbbl)			BOE (Mboe)		
	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—	—	—	—	—
Canada	—	—	—	453	453	362	14,630	14,623	12,797	68,451	68,431	60,409
France	—	—	—	—	—	—	—	—	—	5,429	5,429	4,871
Germany	—	—	—	—	—	—	—	—	—	1,069	1,069	953
Hungary	—	—	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	—	—	—	705	705	705
United States	—	—	—	—	—	—	1,642	1,642	1,363	13,442	13,442	11,124
Total Proved Undeveloped	**—**	**—**	**—**	**453**	**453**	**362**	**16,272**	**16,265**	**14,160**	**89,096**	**89,076**	**78,062**

Proved [3]	Light & Medium Crude Oil (Mbbl)			Heavy Oil (Mbbl)			Tight Oil (Mbbl)			Conventional Natural Gas (MMcf)		
	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]
Australia	9,668	9,668	9,668	—	—	—	—	—	—	—	—	—
Canada	94,723	94,565	83,723	100	100	86	—	—	—	318,750	318,341	292,808
France	42,379	42,379	38,387	—	—	—	—	—	—	6,521	6,521	5,956
Germany	5,738	5,738	5,587	—	—	—	—	—	—	43,519	43,519	37,054
Hungary	—	—	—	—	—	—	—	—	—	788	788	630
Ireland	—	—	—	—	—	—	—	—	—	78,560	78,560	78,560
Netherlands	—	—	—	—	—	—	—	—	—	69,706	69,706	69,239
United States	12,989	12,989	10,753	—	—	—	—	—	—	44,705	44,705	37,204
Total Proved	**165,497**	**165,339**	**148,118**	**100**	**100**	**86**	**—**	**—**	**—**	**562,549**	**562,140**	**521,451**

Proved [3]	Shale Gas (MMcf)			Coal Bed Methane (MMcf)			Natural Gas Liquids (Mbbl)			BOE (Mboe)		
	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]	Company Interest [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—	—	9,668	9,668	9,668
Canada	906	906	860	1,828	1,828	1,652	33,535	33,486	28,451	181,939	181,664	161,480
France	—	—	—	—	—	—	—	—	—	43,466	43,466	39,380
Germany	—	—	—	—	—	—	—	—	—	12,991	12,991	11,763
Hungary	—	—	—	—	—	—	—	—	—	131	131	105
Ireland	—	—	—	—	—	—	—	—	—	13,093	13,093	13,093
Netherlands	—	—	—	—	—	—	184	184	183	11,802	11,802	11,723
United States	—	—	—	—	—	—	4,707	4,707	3,916	25,147	25,147	20,870
Total Proved	**906**	**906**	**860**	**1,828**	**1,828**	**1,652**	**38,426**	**38,377**	**32,550**	**298,237**	**297,962**	**268,082**

Probable [4]	Light & Medium Crude Oil (Mbbl) Company Interest [2]	Gross [2]	Net [2]	Heavy Oil (Mbbl) Company Interest [2]	Gross [2]	Net [2]	Tight Oil (Mbbl) Company Interest [2]	Gross [2]	Net [2]	Conventional Natural Gas (MMcf) Company Interest [2]	Gross [2]	Net [2]
Australia	4,812	4,812	4,812	—	—	—	—	—	—	—	—	—
Canada	46,426	46,379	40,751	83	83	71	—	—	—	212,151	212,020	193,166
France	20,355	20,355	18,389	—	—	—	—	—	—	580	580	549
Germany	3,841	3,841	3,740	—	—	—	—	—	—	53,415	53,415	45,837
Hungary	—	—	—	—	—	—	—	—	—	356	356	285
Ireland	—	—	—	—	—	—	—	—	—	44,890	44,890	44,890
Netherlands	—	—	—	—	—	—	—	—	—	61,527	61,527	58,287
United States	20,223	20,223	16,829	—	—	—	—	—	—	39,681	39,681	33,130
Total Probable	**95,657**	**95,610**	**84,521**	**83**	**83**	**71**	**—**	**—**	**—**	**412,600**	**412,469**	**376,144**

Probable [4]	Shale Gas (MMcf) Company Interest [2]	Gross [2]	Net [2]	Coal Bed Methane (MMcf) Company Interest [2]	Gross [2]	Net [2]	Natural Gas Liquids (Mbbl) Company Interest [2]	Gross [2]	Net [2]	BOE (Mboe) Company Interest [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—	—	4,812	4,812	4,812
Canada	213	213	202	2,856	2,856	2,657	20,518	20,502	17,381	102,897	102,812	90,874
France	—	—	—	—	—	—	—	—	—	20,452	20,452	18,481
Germany	—	—	—	—	—	—	—	—	—	12,744	12,744	11,380
Hungary	—	—	—	—	—	—	—	—	—	59	59	48
Ireland	—	—	—	—	—	—	—	—	—	7,482	7,482	7,482
Netherlands	—	—	—	—	—	—	140	140	134	10,395	10,395	9,849
United States	—	—	—	—	—	—	4,231	4,231	3,532	31,068	31,068	25,883
Total Probable	**213**	**213**	**202**	**2,856**	**2,856**	**2,657**	**24,889**	**24,873**	**21,047**	**189,909**	**189,824**	**168,809**

Proved Plus Probable [3] [4]	Light & Medium Crude Oil (Mbbl) Company Interest [2]	Gross [2]	Net [2]	Heavy Oil (Mbbl) Company Interest [2]	Gross [2]	Net [2]	Tight Oil (Mbbl) Company Interest [2]	Gross [2]	Net [2]	Conventional Natural Gas (MMcf) Company Interest [2]	Gross [2]	Net [2]
Australia	14,480	14,480	14,480	—	—	—	—	—	—	—	—	—
Canada	141,149	140,944	124,474	183	183	157	—	—	—	530,901	530,361	485,974
France	62,734	62,734	56,776	—	—	—	—	—	—	7,101	7,101	6,505
Germany	9,579	9,579	9,327	—	—	—	—	—	—	96,934	96,934	82,891
Hungary	—	—	—	—	—	—	—	—	—	1,144	1,144	915
Ireland	—	—	—	—	—	—	—	—	—	123,450	123,450	123,450
Netherlands	—	—	—	—	—	—	—	—	—	131,233	131,233	127,526
United States	33,212	33,212	27,582	—	—	—	—	—	—	84,386	84,386	70,334
Total Proved Plus Probable	**261,154**	**260,949**	**232,639**	**183**	**183**	**157**	**—**	**—**	**—**	**975,149**	**974,609**	**897,595**

Proved Plus Probable [3] [4]	Shale Gas (MMcf) Company Interest [2]	Gross [2]	Net [2]	Coal Bed Methane (MMcf) Company Interest [2]	Gross [2]	Net [2]	Natural Gas Liquids (Mbbl) Company Interest [2]	Gross [2]	Net [2]	BOE (Mboe) Company Interest [2]	Gross [2]	Net [2]
Australia	—	—	—	—	—	—	—	—	—	14,480	14,480	14,480
Canada	1,119	1,119	1,062	4,684	4,684	4,309	54,053	53,988	45,832	284,836	284,476	252,354
France	—	—	—	—	—	—	—	—	—	63,918	63,918	57,860
Germany	—	—	—	—	—	—	—	—	—	25,735	25,735	23,142
Hungary	—	—	—	—	—	—	—	—	—	191	191	153
Ireland	—	—	—	—	—	—	—	—	—	20,575	20,575	20,575
Netherlands	—	—	—	—	—	—	324	324	317	22,196	22,196	21,571
United States	—	—	—	—	—	—	8,938	8,938	7,448	56,214	56,214	46,752
Total Proved Plus Probable	**1,119**	**1,119**	**1,062**	**4,684**	**4,684**	**4,309**	**63,315**	**63,250**	**53,597**	**488,145**	**487,785**	**436,887**

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) "Company Interest Reserves" are Vermilion's interest (operating, non-operating, or royalty) share before deduction of royalty obligations. "Gross Reserves" are Vermilion's working interest (operating or non-operating) share before deduction of royalty obligations 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	(109,586)	10,861	63,031	85,041	93,335	29,243	83,259	101,656	105,449	103,363
Canada	2,694,735	2,024,162	1,632,778	1,375,039	1,192,465	2,694,735	2,024,162	1,632,778	1,375,039	1,192,465
France	1,977,144	1,421,095	1,106,155	908,870	774,933	1,580,780	1,139,226	886,438	727,288	618,912
Germany	253,903	244,742	212,413	184,815	163,319	253,903	244,742	212,413	184,815	163,319
Hungary	5,139	5,052	4,958	4,861	4,764	5,139	5,052	4,958	4,861	4,764
Ireland	485,088	452,190	415,558	381,680	352,090	485,088	452,190	415,558	381,680	352,090
Netherlands	179,089	184,378	184,810	182,502	178,684	127,769	134,910	137,025	136,254	133,846
United States	231,348	175,747	140,062	116,427	99,999	231,348	175,747	140,062	116,427	99,999
Total Proved Developed Producing	**5,716,860**	**4,518,227**	**3,759,765**	**3,239,235**	**2,859,589**	**5,408,005**	**4,259,288**	**3,530,888**	**3,031,813**	**2,668,758**
Proved Developed Non-Producing (2) (4) (6)										
Australia	126,701	114,643	104,347	95,530	87,940	80,629	73,355	67,136	61,803	57,205
Canada	396,540	232,682	161,723	122,868	98,447	396,540	232,682	161,723	122,868	98,447
France	14,014	10,433	7,696	5,745	4,353	10,251	7,342	5,164	3,630	2,545
Germany	54,365	42,699	31,802	23,711	17,969	31,093	30,003	24,477	19,274	15,166
Hungary	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	126,748	118,915	110,167	101,731	94,034	74,494	70,668	65,369	59,927	54,849
United States	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	**718,368**	**519,372**	**415,735**	**349,585**	**302,743**	**593,007**	**414,050**	**323,869**	**267,502**	**228,212**
Proved Undeveloped (2) (7)										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	1,670,826	1,071,733	731,058	520,018	380,333	1,181,099	794,257	560,418	409,379	305,726
France	249,616	185,758	141,008	109,420	86,532	182,439	130,733	95,339	70,792	53,289
Germany	47,534	35,947	27,549	21,413	16,889	32,298	24,895	19,360	15,225	12,130
Hungary	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	13,015	9,953	7,586	5,780	4,401	8,808	6,168	4,156	2,651	1,532
United States	414,769	245,233	157,651	107,119	75,427	379,311	228,652	149,288	102,635	72,899
Total Proved Undeveloped	**2,395,760**	**1,548,624**	**1,064,852**	**763,750**	**563,582**	**1,783,955**	**1,184,705**	**828,561**	**600,682**	**445,576**
Proved (2)										
Australia	17,115	125,504	167,378	180,571	181,275	109,872	156,614	168,792	167,252	160,568
Canada	4,762,101	3,328,577	2,525,559	2,017,925	1,671,245	4,272,374	3,051,101	2,354,919	1,907,286	1,596,638
France	2,240,774	1,617,286	1,254,859	1,024,035	865,818	1,773,470	1,277,301	986,941	801,710	674,746
Germany	355,802	323,388	271,764	229,939	198,177	317,294	299,640	256,250	219,314	190,615
Hungary	5,139	5,052	4,958	4,861	4,764	5,139	5,052	4,958	4,861	4,764
Ireland	485,088	452,190	415,558	381,680	352,090	485,088	452,190	415,558	381,680	352,090
Netherlands	318,852	313,246	302,563	290,013	277,119	211,071	211,746	206,550	198,832	190,227
United States	646,117	420,980	297,713	223,546	175,426	610,659	404,399	289,350	219,062	172,898
Total Proved	**8,830,988**	**6,586,223**	**5,240,352**	**4,352,570**	**3,725,914**	**7,784,967**	**5,858,043**	**4,683,318**	**3,899,997**	**3,342,546**
Probable (3)										
Australia	177,097	166,788	141,578	117,490	97,745	107,160	97,381	80,581	65,404	53,312
Canada	3,352,766	1,965,403	1,318,031	960,203	739,387	2,439,399	1,428,804	958,923	700,822	542,662
France	1,307,482	733,655	477,702	339,516	255,292	961,077	527,612	334,148	230,483	167,951
Germany	493,459	309,609	201,184	138,746	100,380	336,112	208,631	131,533	88,015	61,870
Hungary	2,034	1,938	1,844	1,757	1,676	2,034	1,938	1,844	1,757	1,676
Ireland	291,025	213,302	158,986	122,050	96,615	291,025	213,302	158,986	122,050	96,615
Netherlands	364,483	292,074	241,201	203,211	174,039	233,493	179,879	143,735	117,500	97,858
United States	1,232,905	671,458	419,216	286,138	207,425	974,062	531,802	333,922	229,769	168,157
Total Probable	**7,221,251**	**4,354,227**	**2,959,742**	**2,169,111**	**1,672,559**	**5,344,362**	**3,189,349**	**2,143,672**	**1,555,800**	**1,190,101**

	Before Deducting Future Income Taxes Discounted At					After Deducting Future Income Taxes Discounted At				
(M$)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved Plus Probable (2) (3)										
Australia	194,212	292,292	308,956	298,061	279,020	217,032	253,995	249,373	232,656	213,880
Canada	8,114,867	5,293,980	3,843,590	2,978,128	2,410,632	6,711,773	4,479,905	3,313,842	2,608,108	2,139,300
France	3,548,256	2,350,941	1,732,561	1,363,551	1,121,110	2,734,547	1,804,913	1,321,089	1,032,193	842,697
Germany	849,261	632,997	472,948	368,685	298,557	653,406	508,271	387,783	307,329	252,485
Hungary	7,173	6,990	6,802	6,618	6,440	7,173	6,990	6,802	6,618	6,440
Ireland	776,113	665,492	574,544	503,730	448,705	776,113	665,492	574,544	503,730	448,705
Netherlands	683,335	605,320	543,764	493,224	451,158	444,564	391,625	350,285	316,332	288,085
United States	1,879,022	1,092,438	716,929	509,684	382,851	1,584,721	936,201	623,272	448,831	341,055
Total Proved Plus Probable	**16,052,239**	**10,940,450**	**8,200,094**	**6,521,681**	**5,398,473**	**13,129,329**	**9,047,392**	**6,826,990**	**5,455,797**	**4,532,647**

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	932,986	—	637,735	45,715	232,422	17,114	(92,757)	109,871
Canada	10,920,607	1,555,228	3,216,466	1,073,070	313,742	4,762,101	489,727	4,272,374
France	4,175,553	390,333	1,174,328	157,216	212,901	2,240,775	467,303	1,773,472
Germany	905,663	68,514	299,677	26,662	155,009	355,801	38,507	317,294
Hungary	8,538	1,708	1,458	—	234	5,138	—	5,138
Ireland	736,043	—	167,945	20,236	62,775	485,087	—	485,087
Netherlands	713,007	4,366	234,628	34,261	120,900	318,852	107,779	211,073
United States	1,697,784	460,566	372,196	196,412	22,494	646,116	35,458	610,658
Total Proved	**20,090,181**	**2,480,715**	**6,104,433**	**1,553,572**	**1,120,477**	**8,830,984**	**1,046,017**	**7,784,967**
Proved Plus Probable (2) (3)								
Australia	1,435,300	—	882,937	109,033	249,118	194,212	(22,820)	217,032
Canada	17,480,753	2,486,902	4,944,114	1,556,839	378,031	8,114,867	1,403,094	6,711,773
France	6,410,853	604,900	1,667,771	329,026	260,901	3,548,255	813,709	2,734,546
Germany	1,821,205	148,845	501,157	115,171	206,772	849,260	195,854	653,406
Hungary	12,223	2,445	2,362	—	244	7,172	—	7,172
Ireland	1,157,656	—	270,779	41,456	69,308	776,113	—	776,113
Netherlands	1,321,585	32,878	386,816	79,502	139,055	683,334	238,769	444,565
United States	4,242,199	1,139,208	748,219	441,298	34,453	1,879,021	294,301	1,584,720
Total Proved Plus Probable	**33,881,774**	**4,415,178**	**9,404,155**	**2,672,325**	**1,337,882**	**16,052,234**	**2,922,907**	**13,129,327**

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) ($M)	Unit Value ($/boe)
Proved Developed Producing		
Light Crude Oil & Medium Crude Oil (3)	2,670,068	24.93
Heavy Oil (3)	534	17.21
Conventional Natural Gas (4)	1,089,855	16.25
Shale Gas	595	3.28
Coal Bed Methane	(1,288)	(13.15)
Total Proved Developed Producing	**3,759,764**	**21.54**
Proved Developed Non-Producing		
Light Crude Oil & Medium Crude Oil (3)	259,974	30.17
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	155,725	23.01
Shale Gas	—	—
Coal Bed Methane	35	0.30
Total Proved Developed Non-Producing	**415,734**	**26.82**
Proved Undeveloped		
Light Crude Oil & Medium Crude Oil (3)	874,455	15.77
Heavy Oil (3)	442	4.14
Conventional Natural Gas (4)	189,956	8.47
Shale Gas	—	—
Coal Bed Methane	—	—
Total Proved Undeveloped	**1,064,853**	**13.64**
Proved		
Light Crude Oil & Medium Crude Oil (3)	3,800,594	22.20
Heavy Oil (3)	965	7.02
Conventional Natural Gas (4)	1,439,468	14.94
Shale Gas	607	3.34
Coal Bed Methane	(1,281)	(4.64)
Total Proved	**5,240,353**	**19.55**
Probable		
Light Crude Oil & Medium Crude Oil (3)	2,114,294	20.44
Heavy Oil (3)	1,618	14.19
Conventional Natural Gas (4)	841,663	13.00
Shale Gas	227	5.25
Coal Bed Methane	1,940	4.37
Total Probable	**2,959,742**	**17.53**
Proved Plus Probable		
Light Crude Oil & Medium Crude Oil (3)	5,916,129	21.54
Heavy Oil (3)	2,542	10.11
Conventional Natural Gas (4)	2,280,029	14.15
Shale Gas	838	3.73
Coal Bed Methane	556	0.77
Total Proved Plus Probable	**8,200,094**	**18.77**

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)(2)

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 ($Cdn/ MMBtu)	UK National Balancing Point ($US/MMBtu)	FOB Field Gate ($Cdn/bbl)	Inflation Rate Percent Per Year	US/CAD Exchange Rate	CAD/EUR Exchange Rate
2018	64.74	70.92	71.25	71.55	1.33	7.87	46.70	2.20%	0.77	1.53
Forecast										
2019	56.25	63.33	58.90	63.25	1.85	8.10	30.04	2.00%	0.75	1.52
2020	63.00	75.32	70.05	68.50	2.29	7.90	39.12	2.00%	0.77	1.49
2021	67.00	79.75	74.16	71.25	2.67	7.75	44.15	2.00%	0.79	1.46
2022	70.00	81.48	75.78	73.00	2.90	7.60	47.73	2.00%	0.81	1.42
2023	72.50	83.54	77.69	75.50	3.14	7.60	49.54	2.00%	0.82	1.40
2024	75.00	86.06	80.04	78.00	3.23	7.60	51.00	2.00%	0.83	1.39
2025	77.50	89.09	82.85	80.50	3.34	7.60	52.76	2.00%	0.83	1.39
2026	80.41	92.62	86.13	83.41	3.41	7.75	54.76	2.00%	0.83	1.39
2027	82.02	94.57	87.95	85.02	3.48	7.90	55.89	2.00%	0.83	1.39
2028	83.66	96.56	89.80	86.66	3.54	7.90	57.04	2.00%	0.83	1.39
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.83	1.39

Note:

(1) The pricing assumptions used in the GLJ Report with respect to net present value of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth above. The pricing assumptions above were provided by GLJ, an independent qualified reserves evaluator appointed pursuant to NI 51-101.

(2) For light oil and medium crude oil, the pricing assumptions used are WTI, Edmonton Par Price, Cromer Medium, and Brent Blend. For conventional natural gas in Canada, the pricing assumptions used are AECO and for conventional natural gas in Europe, the pricing assumptions used are National Balancing Point. The NGL price is an aggregate of the individual natural gas liquids prices used in the Total Proved plus Probable evaluation.

For 2018, average realized prices before hedging were:

Country	Crude oil ($/bbl)	NGLs ($/bbl)	Natural gas ($/mcf)
Australia	95.11	—	—
Canada	69.39	44.65	1.54
France	89.68	—	1.74
Germany	84.14	—	8.70
Hungary	—	—	9.79
Ireland	—	—	10.19
Netherlands	—	74.85	9.71
United States	79.40	28.43	2.67

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, 2018 compared to such reserves as at December 31, 2017 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 (3)

Australia		Total Oil (4)			Light & Medium Crude Oil			Heavy Oil			Tight Oil	
Proved Probable P+P (1) (2)	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2017	10,915	4,650	15,565	10,915	4,650	15,565	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	393	162	555	393	162	555	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(1,640)	—	(1,640)	(1,640)	—	(1,640)	—	—	—	—	—	—
At December 31, 2018	**9,668**	**4,812**	**14,480**	**9,668**	**4,812**	**14,480**	**—**	**—**	**—**	**—**	**—**	**—**

Australia		Total Gas (4)			Conventional Natural Gas			Coal Bed Methane			Shale Gas	
Proved Probable P+P (1) (2)	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2018	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Australia		Natural Gas Liquids			BOE	
Proved Probable P+P (1) (2)	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2017	—	—	—	10,915	4,650	15,565
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	393	162	555
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(1,640)	—	(1,640)
At December 31, 2018	**—**	**—**	**—**	**9,668**	**4,812**	**14,480**

Canada		Total Oil (4)			Light & Medium Crude Oil			Heavy Oil			Tight Oil	
Proved Probable P+P (1) (2) Factors	Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)
At December 31, 2017	19,660	12,885	32,545	19,660	12,885	32,545	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	14,762	3,554	18,316	14,686	3,582	18,268	76	(28)	48	—	—	—
Technical Revisions	954	(3,378)	(2,424)	946	(3,371)	(2,425)	8	(7)	1	—	—	—
Acquisitions	65,976	33,138	99,114	65,946	33,020	98,966	30	118	148	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(337)	263	(74)	(337)	263	(74)	—	—	—	—	—	—
Production	(6,351)	—	(6,351)	(6,337)	—	(6,337)	(14)	—	(14)	—	—	—
At December 31, 2018	**94,664**	**46,462**	**141,126**	**94,564**	**46,379**	**140,943**	**100**	**83**	**183**	**—**	**—**	**—**

Canada		Total Gas (4)			Conventional Natural Gas			Coal Bed Methane			Shale Gas	
Proved Probable P+P (1) (2) Factors	Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Proved (MMcf)	Probable (MMcf)	P+P (MMcf)
At December 31, 2017	248,148	184,322	432,470	240,296	181,055	421,351	6,713	3,053	9,766	1,139	214	1,353
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	56,608	6,215	62,823	56,608	6,215	62,823	—	—	—	—	—	—
Technical Revisions	13,722	(6,387)	7,335	15,559	(5,445)	10,114	(1,626)	(937)	(2,563)	(211)	(5)	(216)
Acquisitions	54,983	29,877	84,860	54,983	29,877	84,860	—	—	—	—	—	—
Dispositions	(799)	(558)	(1,357)	(15)	(37)	(52)	(784)	(521)	(1,305)	—	—	—
Economic Factors	(4,368)	1,620	(2,748)	(1,872)	355	(1,517)	(2,475)	1,261	(1,214)	(21)	4	(17)
Production	(47,218)	—	(47,218)	(47,218)	—	(47,218)	—	—	—	—	—	—
At December 31, 2018	**321,076**	**215,089**	**536,165**	**318,341**	**212,020**	**530,361**	**1,828**	**2,856**	**4,684**	**907**	**213**	**1,120**

Canada		Natural Gas Liquids			BOE	
Proved Probable P+P (1) (2) Factors	Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Proved (Mboe)	Probable (Mboe)	P+P (Mboe)
At December 31, 2017	20,304	14,282	34,586	81,322	57,887	139,209
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	7,092	1,145	8,237	31,289	5,735	37,024
Technical Revisions	4,119	2,655	6,774	7,360	(1,788)	5,572
Acquisitions	5,597	2,409	8,006	80,737	40,527	121,264
Dispositions	—	(1)	(1)	(133)	(94)	(227)
Economic Factors	(96)	13	(83)	(1,161)	546	(615)
Production	(3,529)	—	(3,529)	(17,750)	—	(17,750)
At December 31, 2018	**33,487**	**20,503**	**53,990**	**181,664**	**102,813**	**284,477**

France Proved Probable P+P [1] [2] Factors	Total Oil [4] Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Light & Medium Crude Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Heavy Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Tight Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)
At December 31, 2017	40,647	21,786	62,433	40,647	21,786	62,433	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	2,249	(315)	1,934	2,249	(315)	1,934	—	—	—	—	—	—
Technical Revisions	3,558	(411)	3,147	3,558	(411)	3,147	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	40	(706)	(666)	40	(706)	(666)	—	—	—	—	—	—
Production	(4,114)	—	(4,114)	(4,114)	—	(4,114)	—	—	—	—	—	—
At December 31, 2018	**42,380**	**20,354**	**62,734**	**42,380**	**20,354**	**62,734**	**—**	**—**	**—**	**—**	**—**	**—**

France Proved Probable P+P [1] [2] Factors	Total Gas [4] Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Conventional Natural Gas Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Coal Bed Methane Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Shale Gas Proved (MMcf)	Probable (MMcf)	P+P (MMcf)
At December 31, 2017	8,683	1,854	10,537	8,683	1,854	10,537	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	(1,884)	(719)	(2,603)	(1,884)	(719)	(2,603)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(2)	(554)	(556)	(2)	(554)	(556)	—	—	—	—	—	—
Production	(275)	—	(275)	(275)	—	(275)	—	—	—	—	—	—
At December 31, 2018	**6,522**	**581**	**7,103**	**6,522**	**581**	**7,103**	**—**	**—**	**—**	**—**	**—**	**—**

France Proved Probable P+P [1] [2] Factors	Natural Gas Liquids Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	BOE Proved (Mboe)	Probable (Mboe)	P+P (Mboe)
At December 31, 2017	—	—	—	42,094	22,095	64,189
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	2,249	(315)	1,934
Technical Revisions	—	—	—	3,244	(531)	2,713
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	40	(798)	(758)
Production	—	—	—	(4,160)	—	(4,160)
At December 31, 2018	**—**	**—**	**—**	**43,467**	**20,451**	**63,918**

Germany	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2017	5,788	3,000	8,788	5,788	3,000	8,788	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	520	1,121	1,641	520	1,121	1,641	—	—	—	—	—	—
Technical Revisions	(126)	(277)	(403)	(126)	(277)	(403)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	9	(3)	6	9	(3)	6	—	—	—	—	—	—
Production	(455)	—	(455)	(455)	—	(455)	—	—	—	—	—	—
At December 31, 2018	**5,736**	**3,841**	**9,577**	**5,736**	**3,841**	**9,577**	**—**	**—**	**—**	**—**	**—**	**—**

Germany	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2017	41,110	53,134	94,244	41,110	53,134	94,244	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	918	2,185	3,103	918	2,185	3,103	—	—	—	—	—	—
Technical Revisions	6,628	(1,851)	4,777	6,628	(1,851)	4,777	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	48	(53)	(5)	48	(53)	(5)	—	—	—	—	—	—
Production	(5,185)	—	(5,185)	(5,185)	—	(5,185)	—	—	—	—	—	—
At December 31, 2018	**43,519**	**53,415**	**96,934**	**43,519**	**53,415**	**96,934**	**—**	**—**	**—**	**—**	**—**	**—**

Germany	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2017	—	—	—	12,640	11,856	24,496
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	673	1,485	2,158
Technical Revisions	—	—	—	979	(586)	393
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	17	(12)	5
Production	—	—	—	(1,319)	—	(1,319)
At December 31, 2018	**—**	**—**	**—**	**12,990**	**12,743**	**25,733**

Hungary Proved Probable P+P [1] [2] Factors	Total Oil [4] Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Light & Medium Crude Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Heavy Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Tight Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2018	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Hungary Proved Probable P+P [1] [2] Factors	Total Gas [4] Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Conventional Natural Gas Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Coal Bed Methane Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Shale Gas Proved (MMcf)	Probable (MMcf)	P+P (MMcf)
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	1,158	356	1,514	1,158	356	1,514	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(371)	—	(371)	(371)	—	(371)	—	—	—	—	—	—
At December 31, 2018	**787**	**356**	**1,143**	**787**	**356**	**1,143**	**—**	**—**	**—**	**—**	**—**	**—**

Hungary Proved Probable P+P [1] [2] Factors	Natural Gas Liquids Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	BOE Proved (Mboe)	Probable (Mboe)	P+P (Mboe)
At December 31, 2017	—	—	—	—	—	—
Discoveries	—	—	—	193	59	252
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(62)	—	(62)
At December 31, 2018	**—**	**—**	**—**	**131**	**59**	**190**

Ireland	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2018	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Ireland	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2017	81,803	51,389	133,192	81,803	51,389	133,192	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	9,447	(10,967)	(1,520)	9,447	(10,967)	(1,520)	—	—	—	—	—	—
Acquisitions	7,448	4,468	11,916	7,448	4,468	11,916	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(20,138)	—	(20,138)	(20,138)	—	(20,138)	—	—	—	—	—	—
At December 31, 2018	**78,560**	**44,890**	**123,450**	**78,560**	**44,890**	**123,450**	**—**	**—**	**—**	**—**	**—**	**—**

Ireland	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2017	—	—	—	13,634	8,565	22,199
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—
Technical Revisions	—	—	—	1,575	(1,828)	(253)
Acquisitions	—	—	—	1,241	745	1,986
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—
Production	—	—	—	(3,356)	—	(3,356)
At December 31, 2018	**—**	**—**	**—**	**13,094**	**7,482**	**20,576**

Netherlands		Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil	
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions		—	—		—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2018	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Netherlands		Total Gas [4]			Conventional Natural Gas			Coal Bed Methane			Shale Gas	
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2017	60,926	44,380	105,306	60,926	44,380	105,306	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,533	11,604	13,137	1,533	11,604	13,137	—	—	—	—	—	—
Technical Revisions	1,199	(1,129)	70	1,199	(1,129)	70	—	—	—	—	—	—
Acquisitions	22,781	6,731	29,512	22,781	6,731	29,512	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(26)	(59)	(85)	(26)	(59)	(85)	—	—	—	—	—	—
Production	(16,706)	—	(16,706)	(16,706)	—	(16,706)	—	—	—	—	—	—
At December 31, 2018	**69,707**	**61,527**	**131,234**	**69,707**	**61,527**	**131,234**	**—**	**—**	**—**	**—**	**—**	**—**

Netherlands		Natural Gas Liquids			BOE	
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2017	193	119	312	10,347	7,516	17,863
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	—	11	11	256	1,945	2,201
Technical Revisions	6	(2)	4	206	(190)	16
Acquisitions	41	13	54	3,838	1,135	4,973
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(4)	(10)	(14)
Production	(55)	—	(55)	(2,839)	—	(2,839)
At December 31, 2018	**185**	**141**	**326**	**11,804**	**10,396**	**22,200**

United States	Total Oil [4]			Light & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2017	4,282	7,073	11,355	4,282	7,073	11,355	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,071	3,486	4,557	1,071	3,486	4,557	—	—	—	—	—	—
Technical Revisions	312	1,362	1,674	312	1,362	1,674	—	—	—	—	—	—
Acquisitions	7,713	8,302	16,015	7,713	8,302	16,015	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(390)	—	(390)	(390)	—	(390)	—	—	—	—	—	—
At December 31, 2018	**12,988**	**20,223**	**33,211**	**12,988**	**20,223**	**33,211**	**—**	**—**	**—**	**—**	**—**	**—**

United States	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2017	4,380	7,520	11,900	4,380	7,520	11,900	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,018	5,155	6,173	1,018	5,155	6,173	—	—	—	—	—	—
Technical Revisions	(522)	1,048	526	(522)	1,048	526	—	—	—	—	—	—
Acquisitions	40,842	25,958	66,800	40,842	25,958	66,800	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(1,013)	—	(1,013)	(1,013)	—	(1,013)	—	—	—	—	—	—
At December 31, 2018	**44,705**	**39,681**	**84,386**	**44,705**	**39,681**	**84,386**	**—**	**—**	**—**	**—**	**—**	**—**

United States	Natural Gas Liquids			BOE		
Proved Probable P+P [1] [2]	Proved	Probable	P+P	Proved	Probable	P+P
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2017	601	1,030	1,631	5,613	9,356	14,969
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	118	561	679	1,359	4,906	6,265
Technical Revisions	73	45	118	298	1,582	1,880
Acquisitions	4,084	2,596	6,680	18,604	15,224	33,828
Dispositions	—	—	—	—	—	—
Economic Factors	(1)	(1)	(2)	(1)	(1)	(2)
Production	(168)	—	(168)	(727)	—	(727)
At December 31, 2018	**4,707**	**4,231**	**8,938**	**25,146**	**31,067**	**56,213**

Total Company Proved Probable P+P (1) (2) Factors	Total Oil (4) Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Light Crude Oil & Medium Crude Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Heavy Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Tight Oil Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)
At December 31, 2017	81,292	49,394	130,686	81,292	49,394	130,686	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	18,602	7,846	26,448	18,526	7,874	26,400	76	(28)	48	—	—	—
Technical Revisions	5,091	(2,542)	2,549	5,083	(2,535)	2,548	8	(7)	1	—	—	—
Acquisitions	73,689	41,440	115,129	73,659	41,322	114,981	30	118	148	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(288)	(446)	(734)	(288)	(446)	(734)	—	—	—	—	—	—
Production	(12,950)	—	(12,950)	(12,936)	—	(12,936)	(14)	—	(14)	—	—	—
At December 31, 2018	**165,436**	**95,692**	**261,128**	**165,336**	**95,609**	**260,945**	**100**	**83**	**183**	**—**	**—**	**—**

Total Company Proved Probable P+P (1) (2) Factors	Total Gas (4) Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Conventional Natural Gas Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Coal Bed Methane (5) Proved (MMcf)	Probable (MMcf)	P+P (MMcf)	Shale Gas (5) Proved (MMcf)	Probable (MMcf)	P+P (MMcf)
At December 31, 2017	445,050	342,599	787,649	437,198	339,332	776,530	6,713	3,053	9,766	1,139	214	1,353
Discoveries	1,158	356	1,514	1,158	356	1,514	—	—	—	—	—	—
Extensions & Improved Recovery	60,077	25,159	85,236	60,077	25,159	85,236	—	—	—	—	—	—
Technical Revisions	28,590	(20,005)	8,585	30,427	(19,063)	11,364	(1,626)	(937)	(2,563)	(211)	(5)	(216)
Acquisitions	126,054	67,034	193,088	126,054	67,034	193,088	—	—	—	—	—	—
Dispositions	(799)	(558)	(1,357)	(15)	(37)	(52)	(784)	(521)	(1,305)	—	—	—
Economic Factors	(4,348)	954	(3,394)	(1,852)	(311)	(2,163)	(2,475)	1,261	(1,214)	(21)	4	(17)
Production	(90,906)	—	(90,906)	(90,906)	—	(90,906)	—	—	—	—	—	—
At December 31, 2018	**564,876**	**415,539**	**980,415**	**562,141**	**412,470**	**974,611**	**1,828**	**2,856**	**4,684**	**907**	**213**	**1,120**

Total Company Proved Probable P+P (1) (2) Factors	Natural Gas Liquids Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	BOE Proved (Mboe)	Probable (Mboe)	P+P (Mboe)
At December 31, 2017	21,098	15,431	36,529	176,565	121,925	298,490
Discoveries	—	—	—	193	59	252
Extensions & Improved Recovery	7,210	1,717	8,927	35,826	13,756	49,582
Technical Revisions	4,198	2,698	6,896	14,055	(3,179)	10,876
Acquisitions	9,722	5,018	14,740	104,420	57,631	162,051
Dispositions	—	(1)	(1)	(133)	(94)	(227)
Economic Factors	(97)	12	(85)	(1,109)	(275)	(1,384)
Production	(3,752)	—	(3,752)	(31,853)	—	(31,853)
At December 31, 2018	**38,379**	**24,875**	**63,254**	**297,964**	**189,823**	**487,787**

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 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.

Undeveloped reserves

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

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

Timing of initial undeveloped reserves assignment

Undeveloped Reserves Attributed in Current Year

	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		Total Oil Equivalent	
	First Attributed (1)	Booked (Mbbl)	First Attributed (1)	Booked (MMcf)	First Attributed (1)	Booked (MMcf)	First Attributed (1)	Booked (Mbbl)	First Attributed (1)	Booked (Mboe)
Proved										
Prior to 2015	21,277	52,218	88,529	682,707	13,134	59,347	6,557	15,221	44,778	191,115
2015	4,182	15,989	30,963	78,022	333	3,367	2,500	7,287	11,898	36,841
2016	1,411	16,140	25,023	90,934	—	3,043	1,737	7,546	7,319	39,349
2017	2,221	16,816	36,709	99,458	—	2,023	3,988	9,133	12,327	42,863
2018	12,910	50,334	39,940	133,931	—	453	5,649	16,265	25,255	89,074
Probable										
Prior to 2015	30,431	85,534	142,717	440,052	7,773	35,993	8,486	17,399	63,999	182,274
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	17,551	66,919
2017	4,336	28,646	38,537	197,647	—	1,055	2,802	11,455	13,561	73,218
2018	12,521	57,802	49,186	247,148	—	78	5,556	18,176	26,336	117,254

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

Future development costs

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).

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.

(M$)	Total Proved Estimated Using Forecast Prices and Costs (1)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (1)
Australia		
2019	3,120	3,120
2020	19,883	19,883
2021	3,161	55,839
2022	3,144	3,144
2023	3,168	3,168
Remainder	13,239	23,879
Australia total for all years undiscounted	**45,715**	**109,033**
Canada		
2019	310,695	343,959
2020	274,313	328,022
2021	238,743	375,576
2022	92,072	250,534
2023	37,357	84,672
Remainder	119,890	174,076
Canada total for all years undiscounted	**1,073,070**	**1,556,839**
France		
2019	41,703	67,311
2020	40,105	65,370
2021	19,897	75,939
2022	33,256	50,244
2023	9,179	42,773
Remainder	13,076	27,389
France total for all years undiscounted	**157,216**	**329,026**
Germany		
2019	5,453	5,909
2020	4,416	7,379
2021	10,002	28,247
2022	4,692	24,881
2023	1,035	44,254
Remainder	1,064	4,501
Germany total for all years undiscounted	**26,662**	**115,171**
Hungary		
2019	—	—
2020	—	—
2021	—	—
2022	—	—
2023	—	—
Remainder	—	—
Total for all years undiscounted	**—**	**—**

(M$)	Total Proved Estimated Using Forecast Prices and Costs	Total Proved Plus Probable Estimated Using Forecast Prices and Costs
Ireland		
2019	2,053	2,053
2020	—	21,221
2021	—	—
2022	—	—
2023	—	—
Remainder	18,183	18,182
Ireland total for all years undiscounted	**20,236**	**41,456**
Netherlands		
2019	3,511	3,511
2020	10,277	25,681
2021	13,911	18,775
2022	324	15,506
2023	326	10,118
Remainder	5,912	5,911
Netherlands total for all years undiscounted	**34,261**	**79,502**
United States		
2019	19,813	46,453
2020	67,592	67,592
2021	74,914	78,335
2022	25,757	129,770
2023	8,336	119,148
Remainder	—	—
United States total for all years undiscounted	**196,412**	**441,298**
Total Company		
2019	386,348	472,316
2020	416,586	535,148
2021	360,628	632,711
2022	159,245	474,079
2023	59,401	304,133
Remainder	171,364	253,938
Total for all years undiscounted	**1,553,572**	**2,672,325**

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 detailed in "Forecast Prices used in Estimates".

Oil and gas properties and wells

The following table sets forth the number of wells (based on wellbores) in which Vermilion held a working interest as at December 31, 2018:

	Oil				Gas			
	Producing		Non-Producing (4)		Producing		Non-Producing (4)	
	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)
Canada								
Alberta	489	353	167	103	554	397	362	248
Saskatchewan	4,783	2,994	1,758	1,149	—	—	20	20
Total Canada	5,272	3,346	1,925	1,253	554	397	382	268
Australia (1)	17	17	1	1	—	—	—	—
France	344	337	89	88	1	1	2	2
Germany	133	105	40	34	21	8	4	1
Hungary	—	—	—	—	1	1	—	—
Ireland (1)	—	—	—	—	6	1	—	—
Netherlands	—	—	—	—	114	103	49	41
United States (Wyoming)	127	118	56	53	—	—	—	—
Total Vermilion	**5,893**	**3,923**	**2,111**	**1,429**	**697**	**512**	**437**	**312**

Notes:
(1) Wells for Australia and Ireland are located offshore.
(2) "Gross" refers to the total wells in which Vermilion has an interest, directly or indirectly.
(3) "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.
(4) 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, 2018:

(M$)	Acquisition Costs for Proved Properties	Acquisition Costs for Unproved Properties	Exploration Costs	Development Costs	Total Costs
Australia	—	—	—	75,638	75,638
Canada	1,573,964	—	—	277,857	1,851,821
Croatia	—	—	4,850	—	4,850
France	—	—	307	79,451	79,758
Germany	—	1,665	4,943	10,863	17,471
Hungary	(285)	—	4,752	1,009	5,476
Ireland	(5,572)	—	—	224	(5,348)
Netherlands	(2,087)	—	(480)	17,963	15,396
United States	191,740	—	—	40,837	232,577
Total	**1,757,760**	**1,665**	**14,372**	**503,842**	**2,277,639**

Acreage

The following table summarizes the acreage for the year ended December 31, 2018:

	Developed (1)		Undeveloped		Total	Total
	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)(4)	Net (3)(4)
Australia	20,164	20,164	39,389	39,389	59,552	59,552
Canada	813,605	632,930	518,746	455,584	1,332,352	1,088,514
Croatia	—	—	2,350,000	2,350,000	2,350,000	2,350,000
France	258,125	248,873	274,007	251,779	532,132	500,652
Germany	88,603	32,662	2,815,369	1,149,410	2,903,972	1,182,072
Hungary	160	160	652,657	652,657	652,817	652,817
Ireland	7,200	1,440	—	—	7,200	1,440
Netherlands	172,752	54,538	1,689,755	785,257	1,862,507	839,795
Slovakia	—	—	485,591	242,796	485,591	242,796
United States	48,145	42,852	116,944	105,871	165,089	148,723
Total	**1,408,754**	**1,033,618**	**8,942,458**	**6,032,743**	**10,351,212**	**7,066,360**

Notes:
(1) "Developed" means the acreage assigned to productive wells based on applicable regulations.
(2) "Gross" means the total acreage in which Vermilion has a working interest, directly or indirectly.
(3) "Net" means the total acreage in which Vermilion has a working interest, directly or indirectly, multiplied by the percentage working interest of Vermilion.
(4) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Exploration and development activities

The following table sets forth the number of development and exploration wells which Vermilion completed during its 2018 financial year:

	Exploration Wells Gross (1)	Exploration Wells Net (2)	Development Wells Gross (1)	Development Wells Net (2)
Australia				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Australia	**—**	**—**	**—**	**—**
Canada				
Oil	—	—	150.0	115.3
Gas	—	—	23.0	20.7
Dry Holes	—	—	—	—
Total Canada	**—**	**—**	**173.0**	**135.9**
France				
Oil	—	—	5.0	5.0
Gas	—	—	—	—
Dry Holes	—	—	1.0	1.0
Total France	**—**	**—**	**6.0**	**6.0**
Germany				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Germany	**—**	**—**	**—**	**—**
Hungary				
Oil	—	—	—	—
Gas	1.0	1.0	—	—
Dry Holes	—	—	—	—
Total Hungary	**1.0**	**1.0**	**—**	**—**
Ireland				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Ireland	**—**	**—**	**—**	**—**
Netherlands				
Oil	—	—	—	—
Gas	—	—	—	—
Dry Holes	—	—	—	—
Total Netherlands	**—**	**—**	**—**	**—**
United States				
Oil	—	—	5.0	5.0
Gas	—	—	—	—
Dry Holes	1.0	1.0	—	—
Total United States	**1.0**	**1.0**	**5.0**	**5.0**
Total Company				
Oil	—	—	160.0	125.3
Gas	1.0	1.0	23.0	20.7
Dry Holes	1.0	1.0	1.0	1.0
Total Company	**2.0**	**2.0**	**184.0**	**146.9**

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.

Properties with no attributed reserves

The following table sets out Vermilion's properties with no attributed reserves as at December 31, 2018:

Country	Gross Acres (1)	Net Acres
Australia	39,389	39,389
Canada	110,879	97,379
Croatia	2,350,000	2,350,000
France	146,569	134,679
Germany	2,736,892	1,117,371
Hungary	652,585	652,585
Ireland	—	—
Netherlands	1,586,392	737,223
Slovakia	485,591	242,796
United States	58,466	52,931
Total	**8,166,762**	**5,424,350**

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 82,770 (79,934 net) acres in Canada, 635,333 (635,333 net) acres in Croatia, 129,000 (129,000 net) acres in Hungary, 92,663 (92,663 net) acres in France, and 6,879 (4,564 net) acres in the United States 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, Germany, Ireland, the Netherlands and Slovakia. 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 $29.3 million in the next year.

Vermilion’s properties with no attributed reserves do not have any significant abandonment and reclamation costs. 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.

Production estimates

The following table sets forth the volume of production estimated for the year ended December 31, 2019 as reflected in the estimates of gross proved reserves and gross proved plus probable reserves in the GLJ Report:

	Light Crude Oil & Medium Crude Oil (bbl/d)	Heavy Oil (bbl/d)	Tight Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Shale Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbl/d)	BOE (boe/d)
Australia								
Proved	4,330	—	—	—	—	—	—	4,330
Probable	162	—	—	—	—	—	—	162
Proved Plus Probable	**4,492**	**—**	**—**	**—**	**—**	**—**	**—**	**4,492**
Canada								
Proved	27,592	72	—	127,247	356	1,941	11,920	61,175
Probable	3,023	12	—	17,066	12	87	1,532	7,428
Proved Plus Probable	**30,615**	**84**	**—**	**144,313**	**368**	**2,028**	**13,452**	**68,603**
France								
Proved	11,342	—	—	1,215	—	—	—	11,545
Probable	1,077	—	—	11	—	—	—	1,078
Proved Plus Probable	**12,419**	**—**	**—**	**1,226**	**—**	**—**	**—**	**12,623**
Germany								
Proved	1,086	—	—	15,991	—	—	—	3,751
Probable	44	—	—	499	—	—	—	127
Proved Plus Probable	**1,130**	**—**	**—**	**16,490**	**—**	**—**	**—**	**3,878**
Hungary								
Proved	—	—	—	1,893	—	—	—	316
Probable	—	—	—	368	—	—	—	61
Proved Plus Probable	**—**	**—**	**—**	**2,261**	**—**	**—**	**—**	**377**
Ireland								
Proved	—	—	—	46,055	—	—	—	7,676
Probable	—	—	—	1,781	—	—	—	297
Proved Plus Probable	**—**	**—**	**—**	**47,836**	**—**	**—**	**—**	**7,973**
Netherlands								
Proved	—	—	—	51,481	—	—	169	8,749
Probable	—	—	—	4,419	—	—	15	752
Proved Plus Probable	**—**	**—**	**—**	**55,900**	**—**	**—**	**184**	**9,501**
United States								
Proved	2,064	—	—	7,578	—	—	794	4,121
Probable	1,196	—	—	1,553	—	—	163	1,618
Proved Plus Probable	**3,260**	**—**	**—**	**9,131**	**—**	**—**	**957**	**5,739**
Total								
Total Proved	46,414	72	—	251,460	356	1,941	12,883	101,662
Probable	5,502	12	—	25,697	12	87	1,710	11,523
Total Proved Plus Probable	**51,916**	**84**	**—**	**277,157**	**368**	**2,028**	**14,593**	**113,185**

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.

	Three Months Ended March 31, 2018	Three Months Ended June 31, 2018	Three Months Ended September 31, 2018	Three Months Ended December 31, 2018
Australia				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	4,971	4,132	4,704	4,174
Conventional Natural Gas (MMcf/d)	—	—	—	—
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	86.94	98.61	99.01	97.19
Conventional Natural Gas ($/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 ($/bbl)	29.72	33.81	32.00	38.92
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	57.22	64.80	67.01	58.27
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Canada				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	5,960	13,103	24,602	25,640
Conventional Natural Gas (MMcf/d)	106.21	127.32	136.77	146.65
Natural Gas Liquids (bbl/d)	8,417	9,494	10,001	10,734
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	75.50	78.13	79.73	53.67
Conventional Natural Gas ($/Mcf)	1.95	1.09	1.44	1.73
Natural Gas Liquids ($/bbl)	44.57	49.76	48.30	36.82
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	10.08	11.03	12.22	8.17
Conventional Natural Gas ($/Mcf)	0.04	(0.24)	0.02	0.09
Natural Gas Liquids ($/bbl)	5.40	5.87	6.34	5.19
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.38	1.65	1.04	2.62
Conventional Natural Gas ($/Mcf)	0.15	0.16	0.15	0.17
Natural Gas Liquids ($/bbl)	2.38	1.65	1.04	2.62
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	8.94	11.13	11.76	13.09
Conventional Natural Gas ($/Mcf)	1.31	1.11	1.44	1.35
Natural Gas Liquids ($/bbl)	8.94	11.13	11.76	13.09
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	54.10	54.32	54.71	29.79
Conventional Natural Gas ($/Mcf)	0.45	0.06	(0.17)	0.12
Natural Gas Liquids ($/bbl)	27.85	31.11	29.16	15.92

	Three Months Ended March 31, 2018	Three Months Ended June 31, 2018	Three Months Ended September 31, 2018	Three Months Ended December 31, 2018
France				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	11,037	11,683	11,407	11,317
Conventional Natural Gas (MMcf/d)	—	—	—	0.82
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	81.70	95.13	95.46	84.94
Conventional Natural Gas ($/Mcf)	—	—	—	1.74
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	10.60	11.85	12.08	11.86
Conventional Natural Gas ($/Mcf)	—	—	—	0.03
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.65	2.65	1.91	3.21
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	14.66	13.07	13.00	13.88
Conventional Natural Gas ($/Mcf)	—	—	—	—
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	53.79	67.56	68.47	55.99
Conventional Natural Gas ($/Mcf)	—	—	—	1.71
Natural Gas Liquids ($/bbl)	—	—	—	—
Germany				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	1,078	1,008	1,019	913
Conventional Natural Gas (MMcf/d)	16.19	14.63	14.88	16.94
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	79.04	91.00	92.45	75.53
Conventional Natural Gas ($/Mcf)	7.69	7.68	9.61	9.72
Natural Gas Liquids ($/bbl)	—	—	—	—
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.53	2.22	2.14	3.32
Conventional Natural Gas ($/Mcf)	0.99	0.78	1.66	0.57
Natural Gas Liquids ($/bbl)	—	—	—	—
Transportation				
Light Crude Oil and Medium Crude Oil ($/bbl)	9.80	10.17	8.83	9.14
Conventional Natural Gas ($/Mcf)	0.58	0.60	0.32	0.41
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	22.08	22.36	21.41	24.48
Conventional Natural Gas ($/Mcf)	2.46	2.43	2.22	2.84
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	44.63	56.25	60.07	38.59
Conventional Natural Gas ($/Mcf)	3.66	3.87	5.41	5.90
Natural Gas Liquids ($/bbl)	—	—	—	—

	Three Months Ended March 31, 2018	Three Months Ended June 31, 2018	Three Months Ended September 31, 2018	Three Months Ended December 31, 2018
Hungary				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (MMcf/d)	—	—	1.17	2.86
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	—	—	10.06	9.68
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 ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	—	—	1.87	(0.35)
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	—	—	8.19	10.03
Natural Gas Liquids ($/bbl)	—	—	—	—
Ireland				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (MMcf/d)	60.87	56.56	51.38	52.03
Natural Gas Liquids (bbl/d)	—	—	—	—
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	9.80	9.30	10.63	11.15
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)	0.23	0.25	0.31	0.23
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	0.59	0.84	0.71	0.94
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	8.98	8.21	9.61	9.98
Natural Gas Liquids ($/bbl)	—	—	—	—

	Three Months Ended March 31, 2018	Three Months Ended June 31, 2018	Three Months Ended September 31, 2018	Three Months Ended December 31, 2018
Netherlands				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	—	—	—	—
Conventional Natural Gas (MMcf/d)	44.79	43.49	44.37	51.82
Natural Gas Liquids (bbl/d)	77	87	84	112
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	8.86	8.68	10.08	10.95
Natural Gas Liquids ($/bbl)	68.64	79.40	82.32	69.95
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	0.21	0.19	0.26	0.11
Natural Gas Liquids ($/bbl)	—	—	—	—
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	1.91	1.62	1.42	1.42
Natural Gas Liquids ($/bbl)	—	—	—	—
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	—	—	—	—
Conventional Natural Gas ($/Mcf)	6.74	6.87	8.40	9.42
Natural Gas Liquids ($/bbl)	68.64	79.40	82.32	69.95
United States				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	573	652	1,455	1,582
Conventional Natural Gas (MMcf/d)	0.15	0.40	4.82	5.65
Natural Gas Liquids (bbl/d)	21	65	720	1,022
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	76.59	83.93	87.44	71.15
Conventional Natural Gas ($/Mcf)	3.00	1.59	2.01	3.29
Natural Gas Liquids ($/bbl)	37.05	32.24	29.53	27.24
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	21.04	23.19	20.43	19.46
Conventional Natural Gas ($/Mcf)	1.08	0.57	0.53	0.90
Natural Gas Liquids ($/bbl)	11.86	9.23	7.16	8.01
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)	10.60	5.73	9.95	8.68
Conventional Natural Gas ($/Mcf)	—	—	1.45	1.48
Natural Gas Liquids ($/bbl)	10.60	5.73	9.95	8.68
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	44.95	55.01	57.06	43.01
Conventional Natural Gas ($/Mcf)	1.92	1.02	0.03	0.91
Natural Gas Liquids ($/bbl)	14.59	17.28	12.42	10.55

	Three Months Ended March 31, 2018	Three Months Ended June 31, 2018	Three Months Ended September 31, 2018	Three Months Ended December 31, 2018
Total Company				
Average Daily Production				
Light Crude Oil and Medium Crude Oil (bbl/d)	23,619	30,579	43,186	43,625
Conventional Natural Gas (MMcf/d)	228.20	242.40	253.38	276.77
Natural Gas Liquids (bbl/d)	8,515	9,647	10,805	11,867
Average Net Prices Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	80.91	88.00	86.32	67.07
Conventional Natural Gas ($/Mcf)	5.81	4.77	5.35	5.83
Natural Gas Liquids ($/bbl)	44.77	49.91	47.31	36.31
Royalties				
Light Crude Oil and Medium Crude Oil ($/bbl)	7.98	9.80	11.11	8.58
Conventional Natural Gas ($/Mcf)	0.13	(0.04)	0.18	0.14
Natural Gas Liquids ($/bbl)	5.37	5.84	6.35	5.38
Transportation Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.35	1.96	1.24	2.52
Conventional Natural Gas ($/Mcf)	0.17	0.18	0.16	0.16
Natural Gas Liquids ($/bbl)	2.35	1.96	1.24	2.52
Production Costs				
Light Crude Oil and Medium Crude Oil ($/bbl)	14.57	14.21	13.60	15.26
Conventional Natural Gas ($/Mcf)	1.32	1.22	1.34	1.36
Natural Gas Liquids ($/bbl)	14.57	14.21	13.60	15.26
Netback Received				
Light Crude Oil and Medium Crude Oil ($/bbl)	56.01	62.03	60.37	40.71
Conventional Natural Gas ($/Mcf)	4.19	3.41	3.67	4.17
Natural Gas Liquids ($/bbl)	22.48	27.90	26.12	13.15

Tax information

Vermilion pays current taxes in France, the Netherlands and Australia.

In France, current income taxes are applied to taxable income after eligible deductions. Based on legislation passed in 2017, corporate tax rates in France are 34.4% for 2018, 32% for 2019, 28.9% for 2020, 27.4% for 2021 and 25.8% for 2022 forward.

In the Netherlands, current income taxes are applied to taxable income after eligible deductions at a tax rate of 50%.

In Australia, current taxes include both corporate income taxes and Petroleum Resource Rent Tax ("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 applied at a rate of approximately 40% on sales less eligible expenditures, including operating expenses and capital expenditures.

As a function of the impact of Vermilion's tax pools, the Company does not presently pay current taxes in Canada, Germany, Hungary, Ireland and the United States.

The following table sets forth Vermilion's tax pools as at December 31, 2018:

($M)	Oil & Gas Assets		Tax Losses		Other	Total
Australia	298,054	(1)	10,486	(4)	—	308,540
Canada	2,317,044	(1)	1,052,664	(4)	36,192	3,405,900
France	317,062	(2)	11,086	(5)	—	328,148
Germany	175,756	(3)	98,787	(6)	11,932	286,475
Hungary	—		—		—	—
Ireland	—		1,301,395	(4)	—	1,301,395
Netherlands	66,947	(3)	—		—	66,947
United States	214,965	(1)	101,928	(7)	10,184	327,077
Total	**3,389,828**		**2,576,346**		**58,308**	**6,024,482**

Notes:

(1) Deduction calculated using various declining balance rates

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

(3) Deduction calculated using a unit of production method

(4) Tax losses can be carried forward and applied at 100% against taxable income

(5) Tax losses carried forward are available to offset the first €1 million of taxable income and 50% of taxable profits in excess each taxation year

(6) Tax losses carried forward are available to offset the first €1 million of taxable income and 60% of taxable profits in excess each taxation year

(7) Tax losses created prior to January 1, 2018 are carried forward and applied at 100% against taxable income, tax losses created after January 1, 2018 are carried forward and applied to 80% of taxable income in each taxation year

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, 2018 are summarized in Supplemental Table 2: Hedges, included in the Company's 2018 Management's Discussion and Analysis, dated February 27, 2019, available on SEDAR at www.sedar.com, under Vermilion's SEDAR profile.

Directors and Officers

As at January 31, 2019, the directors and officers of Vermilion beneficially owned, or controlled or directed, directly or indirectly, 3,705,699 common shares representing approximately 2.4% 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.

Board of Directors

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

Name and Municipality of Residence	Committee(s)	Office Held	Year First Elected or Appointed as Director	Principal Occupation During the Past Five Years
Lorenzo Donadeo Calgary, Alberta Canada	(1)	Chairman of the Board	1994	Since March 1, 2016, Chairman of the Board of Vermilion March 2014 – March 1, 2016 Chief Executive Officer of Vermilion 2003 – March 2014, President and Chief Executive Officer of Vermilion Since January 2015, Managing Director of a group of private wealth management companies
Stephen Larke Calgary, Alberta Canada	(3) (4) (7)	Director	2017	2016 to 2018, Operating Partner and Advisory Board Member, Azimuth Capital Management, a private equity fund 2005 to 2015, Managing Director and Principal, Institutional Sales, and Executive Committee Member, Peters & Co., a private investment dealer
Loren M. Leiker McKinney, Texas USA	(6)	Director	2012	Since 2014, Director of Navitas Midstream Partners LLC Since 2012, Director of SM Energy, a public energy company 2012 to 2015, Director of Midstates Petroleum, a public exploration and production company
Larry J. Macdonald Okotoks, Alberta Canada	(2) (3) (4) (5)	Lead Director	2002	Since March 1, 2016, Lead Director of Vermilion 2012 to March 1, 2016, Chairman of the Board of Vermilion Since June 2018, Chairman of the Board of United Way Canada Gives Across Borders, a non-profit organization 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.
Timothy R. Marchant Calgary, Alberta Canada	(5) (6) (7)	Director	2010	Since 2015, Non-Executive 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 of Vermilion March 2014 – March 1, 2016, President and Chief Operating Officer of Vermilion June 2012 – March 2014, Executive Vice President and Chief Operating Officer of Vermilion

Robert Michaleski Calgary, Alberta Canada	(3) (4)	Director	2016	2013 to 2018, 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 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
Carin S. Knickel Golden, Colorado USA	(2) (3) (7)	Director	2018	Since 2015, Director of Hudbay Minerals, Inc., a public mining company Since 2015, Director of Whiting Petroleum Corporation, a public oil and gas company Since 2014, Director of National MS Society (Colorado/Wyoming Chapter), a non-profit organization 2012 to 2015, Director of Rosetta Resources Inc., a private oil and gas company 2013 to 2014, Director of University of Colorado Denver, a public research university
William Roby Calgary, Alberta Canada	(5) (6) (7)	Director	2017	Since 2015, Chief Executive Officer, Shepherd Energy, LLC., a private energy efficiency services company 2013 to 2014, Chief Operating Officer, Sheridan Production Company, LLC., a private oil and gas company 2000 to 2013, Senior Vice President and other management positions, Occidental Petroleum Corporation, a public oil and gas company
Catherine L. Williams Calgary, Alberta Canada	(3) (4)	Director	2015	Since 2010, Chair of Human Resources and Compensation Committee, Enbridge Inc., a public energy transportation company Since 2007, Director of Enbridge Inc., a public energy transportation company Since 2007, Owner and Managing Director, Options Canada Ltd., a private investment company 2016 to 2017, Director of Enbridge Income Fund, an energy infrastructure asset investment vehicle 2015 to 2017, Director of Enbridge Pipelines Inc. and Enbridge Income Partners GP Inc., subsidiaries of Enbridge Inc., a public energy transportation company 2015 to 2017, Trustee of Enbridge Commercial Trust, a subsidiary of Enbridge Inc., a public energy transportation company 2009 to 2014, Director, Alberta Investment Management Corporation, an institutional investment fund manager

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
(7) Member of the Sustainability Committee

Officers

Name and Municipality of Residence	Office Held	Principal Occupation During the Past Five Years
Anthony W. Marino Calgary, Alberta Canada	President & Chief Executive Officer	Since March 1, 2016, President and Chief Executive Officer of Vermilion March 2014 – March 1, 2016, President and Chief Operating Officer of Vermilion June 2012 – March 2014, Executive Vice President and Chief Operating Officer of Vermilion
Lars Glemser Calgary, Alberta Canada	Vice President & Chief Financial Officer	Since April 2018, Vice President and Chief Financial Officer of Vermilion December 2017 – April 2018, Director, Finance of Vermilion June 2015 – December 2017, Finance Professional of Vermilion January 2013 – June 2015, Treasurer Lightstream Resources Ltd, a public oil and gas company
Mona Jasinski Calgary, Alberta Canada	Executive Vice President People & Culture	Since February 2015, Executive Vice President, People and Culture of Vermilion 2011 to 2015, Executive Vice President People of Vermilion
Michael Kaluza Calgary, Alberta Canada	Executive Vice President & Chief Operating Officer	Since March 1, 2016, Executive Vice President and Chief Operating Officer of Vermilion May 2014 – March 1, 2016, Vice President, Canada Business Unit of Vermilion 2013 to 2014, Director Canada Business Unit of Vermilion 2012 to 2013, Vice President, Corporate Development and Planning, Baytex Energy Corporation, a public oil and gas company
Anthony (Dion) Hatcher Calgary, Alberta Canada	Vice President Canada Business Unit	Since March 1, 2016, Vice President Canada Business Unit of Vermilion May 1, 2014 to March 1, 2016, Director Alberta Foothills – Canada Business Unit of Vermilion February 2013 to May 2014, Cardium / LRG Development Manager of Vermilion January 2010 to February 2013 – Cardium Development Manager of Vermilion
Terry Hergott Calgary, Alberta Canada	Vice President Marketing	Since April 2012, Vice President, Marketing of Vermilion
Gerard Schut Den Haag The Netherlands	Vice President European Operations	Since July 2012, Vice President European Operations of Vermilion
Jenson Tan Calgary, Alberta Canada	Vice President Business Development	Since October 2017, Vice President, Business Development of Vermilion July 2016 to October 2017, Director, Business Development of Vermilion July 2013 to July 2016, Director, New Ventures of Vermilion November 2010 to July 2013, Business Development Professional of Vermilion
Robert J. Engbloom, Q.C. Calgary, Alberta Canada	Corporate Secretary	Since January 2015, senior partner with Norton Rose Fulbright Canada LLP, a law firm 2012 to 2014, partner with and Deputy Chair of Norton Rose Fulbright Canada LLP, a law firm

Description of Capital Structure

Credit ratings

Credit ratings affect the Company's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in certain collateralized business activities on a cost effective basis depends on the Company's credit ratings. A reduction in the credit rating of the Company or the Company's debt or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company's ability to enter into ordinary course hedging arrangements or contracts with customers and suppliers.

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

As at February 27, 2019, Vermilion had the following credit ratings from Standard & Poors Ratings Services ("S&P") and Moody's Investors Service ("Moody's):

Rating Agency	Company Rating	Outlook	Senior Unsecured Notes
S&P (1)	BB- (1)	Stable	BB- (3)
Moody's (2)	Ba3 (2)	Stable	B2 (4)

Notes:

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

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

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

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

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 pursuant to which a holder may receive Common Shares have been issued under certain Vermilion compensation arrangements. See Vermilion's annual financial statements as at and for the year ended December 31, 2018 (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.

Dividend history

The Company currently pays dividends on a monthly basis. Solvency tests imposed by the ABCA on corporations for the declaration and payment of dividends must be satisfied prior to the declaration of a dividend. In addition, decisions with respect to the declaration of dividends on the common shares will be made by the Board of Directors on the basis of the Company's net earnings, financial requirements, and other conditions. Dividends are generally paid on the 15th day of the month following the month of declaration.

The following table sets forth the history of Vermilion's monthly dividend per share (pre-September 2010 distribution per unit)

Date	Monthly dividend per unit or share
January 2003 to December 2007	$0.170
January 2008 to December 2012	$0.190
January 2013 to December 2013	$0.200
January 2014 to March 2018	$0.215
April 2018 to current	$0.230

The following table outlines dividends declared per share for each of the three most recently completed financial years:

Date	Dividends per common share
January 2016 to December 2016	$2.58
January 2017 to December 2017	$2.58
January 2018 to December 2018	$2.72

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 the Average Market Price (with no broker commissions or trading costs).

From February 2015 to July 2017, Vermilion used the Premium Dividend™ Component of the Dividend Reinvestment Plan to provide access to low cost source of equity capital. Vermilion discontinued the Premium Dividend™ Component in July 2017.

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

™ denotes trademark of Canaccord Genuity Capital Corporation.

Shareholder Rights Plan

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

2018	High	Low	Close	Volume
January	$50.46	$45.74	$46.50	8,487,719
February	$47.11	$40.25	$42.27	9,315,117
March	$42.49	$39.41	$41.54	9,884,429
April	$46.80	$40.01	$43.40	14,079,966
May	$48.36	$42.22	$45.45	19,037,878
June	$47.88	$44.19	$47.41	18,430,700
July	$49.67	$42.98	$44.78	10,415,550
August	$44.72	$39.50	$41.44	12,017,503
September	$43.91	$39.78	$42.56	12,630,581
October	$43.55	$33.94	$34.91	19,874,284
November	$36.09	$30.55	$33.06	22,579,329
December	$34.81	$26.67	$28.76	24,160,048

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 32 years of oil and gas industry experience, with an extensive background in finance, mergers and acquisitions, and business management. Ms. Williams is currently the Owner and Managing Director of Options Canada Ltd. (since 2007) and serves as a Board member of Enbridge Inc. (since 2010) and Chairs its Human Resources and Compensation Committee. She was a Board member of Alberta Investment Management Corporation from 2009 to 2014 and Tim Hortons Inc. from 2009 to 2012. From 2003 to 2007, Ms. Williams held the role of Chief Financial Officer for Shell Canada Ltd., prior to which she held various positions with Shell Canada Limited, Shell Europe Oil Products, Shell Canada Oil Products and Shell International (1984 to 2003).
Stephen Larke	Yes	Yes	Mr. Larke holds a Bachelor of Commerce (Distinction) degree from the University of Calgary and is a Chartered Financial Analyst. He brings over 20 years of experience in energy capital markets, including research, sales, trading and equity finance. From 2017 to 2018, he was Operating Partner and Advisory Board member with Azimuth Capital Management, an energy-focused private equity fund based in Calgary, Alberta. From 2005 to 2015, Mr. Larke was Managing Director and Executive Committee member with Peters & Co., an independent energy investment firm based in Calgary. From 1997 to 2005, he was Vice-President and Director with TD Newcrest, serving in the role of energy equity analyst.
Larry J. Macdonald	Yes	Yes	Mr. Macdonald holds a Bachelor of Science degree from the University of Alberta. He has more than 47 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, 2018 and 2017, Deloitte LLP, the auditors of the Company, received the following fees from the Company:

Item		2018		2017
Audit fees (1)	$	1,934,531	$	1,658,920
Audit-related fees (2)	$	81,500	$	123,000
Tax fees (3)	$	800	$	34,828

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, 2018 and 2017.
(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, 2018, 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 27, 2019.

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 AIF. 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.

Market risks

Volatility of oil and gas prices

The Company's reserves, financial performance, financial position, and cash flows 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. Supply factors can include availability (or lack thereof) of transportation capacity and production curtailments by independent producers or by OPEC members. Demand factors can be impacted by general economic conditions, supply chain requirements, environmental and other factors. Environmental and other factors include changes in weather, weather patterns, fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and gas, and technology advances in fuel economy and energy generation devices.

Volatility of foreign exchange rates

The Company's reserves, financial performance, financial position, and cash flows are affected by prevailing foreign exchange rates. An increase in the exchange rate for the Canadian dollar versus the U.S. dollar and Euro would reduce the Canadian equivalent cash receipts for Vermilion's production. Conversely, a decrease in the exchange rate for the Canadian dollar versus the U.S. dollar and Euro would increase the Canadian equivalent cash outflows for Vermilion's operating and capital expenditures.

Volatility of market price of Common Shares

The market price of Vermilion's Common Shares may be volatile and this volatility may affect the ability of Shareholders to sell Common Shares at an advantageous price. Market price fluctuations in the common shares may be due to: the Company's operating results or financial performance 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 AIF. In addition, the market price for securities in stock markets including Common Shares may experience significant price and trading fluctuations. These fluctuations may result in volatility in the market prices of securities that may be unrelated or disproportionate to changes in the Company's operating and financial performance.

Hedging arrangements

Vermilion may enter into agreements to fix commodity prices, interest rates, and foreign exchange rates to offset the risks affecting the business. To the extent that Vermilion engages in price risk management activities to protect the Company from unfavourable fluctuations in prices and rates, the Company may also be prevented from realizing the full benefits of favourable fluctuations in prices and rates.

To the extent that risk management activities and hedging strategies are employed to address these risks, the Company would also be exposed to risks associated with such activities and strategies, including: counterparty risk, settlement risk, basis risk, liquidity risk and market risk. These risks could impact or negate any benefits of risk management activities and hedging strategies.

In addition, commodity hedging arrangements could expose the Company to the risk of financial loss if: production falls short of the hedged volumes; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangements; or a sudden unexpected event materially impacts oil and natural gas prices.

Operational risks

Increase in operating costs or a decline in production level

The Company's financial performance, financial position, and cash flows are affected by the Company's operating costs and production levels. Operating costs may increase and production levels may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond Vermilion's control.

Production levels may decline due to an inability for Vermilion to market oil and natural gas production. This could result from the availability, proximity and capacity of gathering systems, pipelines and processing facilities that Vermilion depends on in the jurisdictions in which it operates.

Operating costs could increase as a result of blowouts, environmental damage, and other unexpected and dangerous conditions which could result from a number of operating and natural hazards associated with Vermilion's operations. In addition to higher costs, Vermilion may have a potential liability to regulators and third parties as a result. 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.

Operator performance and payment delays

Continuing production from a property are dependent upon the ability of the operator of the property, and the operator may fail to perform these functions properly. 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.

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.

Weather conditions

Vermilion's operations may be impacted by changing weather conditions, which may include: changes in temperature extremes, changes in precipitation patterns (including drought and flooding), rising sea levels, and increased severity of extreme weather events such as cyclones or floods. These events can impact Vermilion's operations, causing shutdowns and increased costs. In the Netherlands, rising water levels could impact facilities below sea level and in Australia a severe cyclonic event could cause damage to the Company's Wandoo platform.

Cost of new technology

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and natural gas companies may have greater financial, technical and personnel resources that provide them with technological advantages and may in the future allow them to implement new technologies before Vermilion does. There can be no assurance that Vermilion will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Company or implemented in the future may become obsolete.

Regulatory and political risks

Tax, royalty and other government legislation

Income tax laws, royalty and other government legislation relating to the oil and gas industry in the jurisdictions in which the Company operates may change in a manner that adversely affects Vermilion.

Government regulations

Vermilion's operations are governed by many levels of governments in which jurisdiction the Company operates. Vermilion is subject to laws and regulations regarding environment, health and safety issues, lease interests, taxes and royalties, among others. Failure to comply with the applicable laws can result in significant increases in costs, penalties and even losses of operating licenses. The regulatory process involved in each of the countries in which Vermilion operates is not uniform and regulatory regimes vary as to complexity, timeliness of access to, and response from, regulatory bodies and other matters specific to each jurisdiction. If regulatory approvals or permits are delayed, not obtained, or revoked, 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 reduced production and increased capital, operating and compliance costs.

Political events and terrorist attacks

Political events throughout the world that cause disruptions in the supply of oil affect the marketability and price of oil and natural gas acquired or discovered by Vermilion. Political developments arising in the countries in which Vermilion operates have a significant impact on the price of oil and natural gas.

Vermilion's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of Vermilion's properties, wells or facilities or any infrastructure on which the Company relies are the subject of a terrorist attack, such attack may have a material adverse effect on Vermilion's financial performance, financial position, and cash flows.

Financing risks

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, including the satisfaction of the liquidity and solvency tests under the ABCA for the declaration and payment of dividends and the amount of the Company's cash flows. The Company's cash flows may be impacted by risks affecting the Company's business including: fluctuations in commodity prices, foreign exchange and interest rates; production and sales volume levels; production costs; capital expenditure requirements; royalty and tax burdens; external financing availability, and debt service requirements.

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, 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.

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.

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 oil and natural gas reserves may 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.

Debt service

Vermilion may 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.

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.

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. A decrease in the exchange rate of the Canadian dollar versus the U.S. dollar would result in higher interest and ultimate principle payment on the Company's U.S. dollar denominated Senior Unsecured Notes.

Environmental risks

Environmental legislation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial, state and federal legislation. A breach of such legislation may result in the imposition of fines, the issuance of clean up orders in respect of Vermilion or its assets, or the loss or suspension of regulatory approvals. Such legislation may include carbon taxes, enhanced emissions reporting obligations, mandates on the equipment specifications, and emissions regulations. Such legislation may be changed to impose higher standards and potentially more costly obligations on Vermilion. In addition, such legislation may inhibit Vermilion's ability to operate the Company's assets and may make it more difficult for Vermilion to compete in the acquisition of new property rights. Presently, the Company does not believe the financial impact of these regulations on capital expenditures and earnings will be material. However, the Company actively monitors and assesses its exposure to this legislation.

Vermilion expects to incur abandonment and reclamation costs in the ordinary course of business as existing oil and gas properties are abandoned and reclaimed. These costs may materially differ from the Company's estimates due to changes in environmental regulations.

Vermilion's exploration and production facilities and other operations and activities emit some amount of greenhouse gases, which may be subject to legislation regulating emissions of greenhouse gases. This may result in a requirement to reduce emissions or emissions intensity from Vermilion's operations and facilities. It is possible that future regulations may require further reductions of emissions or emissions intensity.

Hydraulic fracturing regulations

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

With activist groups expressing concern about the impact of hydraulic fracturing on the environment and water supplies, Vermilion's corporate reputation may be negatively affected by the negative public perception and public protests against hydraulic fracturing. In addition, concerns regarding hydraulic fracturing may result in changes in regulations that delay the development of oil and natural gas resources and adversely affect Vermilion's costs of compliance and reputation. Changes in government may result in new or enhanced regulatory burdens in respect of hydraulic fracturing which could affect Vermilion's business.

Climate change

Climate change may impact the volatility of oil and gas prices and weather conditions affecting Vermilion's operations. These are discussed under "Market risks" and "Operational risks" above. In addition, practices and disclosures relating to environmental matters, including climate change, are attracting increasing scrutiny by stakeholders. Vermilion’s response to addressing environmental matters can impact the Company’s reputation and affect the Company's ability to hire and retain employees; to compete for reserve acquisitions, exploration leases, licenses and concessions; and to receive regulatory approvals required to execute operating programs.

Acquisition and expansion risks

Competition

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

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

International operations and future geographical/industry expansion

The operations and expertise of Vermilion's management are currently focused primarily on oil and natural gas production, exploration and development in three geographical regions, North America, Europe and Australia. In the future Vermilion may: acquire or move into new industry related activities, enter into new geographical areas; or acquire different energy related assets. These actions may result in unexpected risks or alternatively, significantly increase the Company's exposure to one or more existing risk factors.

Acquisition assumptions

When making acquisitions, Vermilion estimates the future performance of the assets to be acquired. These estimates are subject to inherent risks associated with predicting the future performance of those assets. These estimates may not be realized over time. As such, assets acquired may not possess the value Vermilion attributed to them.

Failure to realize anticipated benefits of prior acquisitions

Vermilion may 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. 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.

Reserves and resource estimates

Reserve estimates

Reserves and estimated future net revenue to be derived from reserves are estimates and have been independently evaluated by GLJ. The estimation of reserves is a complex process and requires significant judgment. Actual production and ultimate reserves will vary from those estimates and these variations may be material.

Assumptions incorporated into the estimation of reserves are based on information available when the estimate was prepared. These assumptions are subject to change and many are beyond the Company's control. These assumptions include: 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 costs; royalties, taxes, and other government levies that may be imposed over the producing life of the reserves.

In addition, estimates of reserves that may be developed and produced in the future are often based on methods other than actual production history, including: volumetric calculations, probabilistic methods, and upon analogy to similar types of reserves. Estimates based on these methods are generally 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. As such, reserve estimates may require revision based on actual production experience.

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.

Contingent and prospective resource estimates

Information regarding quantities of contingent and prospective resources included in Appendix A to this Annual Information Form are estimates only. References to “contingent resources” and "prospective 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 may be material.

Other risks

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 damage to the Company's reputation. Vermilion relies upon a variety of advanced controls as protection from such attacks including:

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.

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 and such adjustments may be viewed unfavourably by the market and may result in an inability to borrow funds or a decline in price of Common Shares.

Ineffective internal controls

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

Reliance on key personnel, management and labour

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

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 compete with Vermilion. No assurances can be given that opportunities identified by such persons will be provided to Vermilion.

Brexit

On June 23, 2016, British voters voted to leave the European Union ("Brexit"). This is scheduled to occur on March 29, 2019. As of the date of this AIF, there is significant uncertainty regarding the form of Brexit. Brexit may result in interruptions to Vermilion's business and expose Vermilion to financial volatility, with risks including: disruption in the delivery of supplies to the Company's operations in Ireland, administrative delays to day-to-day banking activities, and foreign exchange volatility.

Vermilion's operations in Ireland are supported by contractors and suppliers, some of whom operate in the United Kingdom. Vermilion currently believes that the ability to mobilize contractor personnel from the United Kingdom to Ireland will not be significantly impacted by Brexit. Vermilion has reviewed all of its UK based suppliers and has identified certain products (predominantly production chemicals and odorant) that are presently sourced from the United Kingdom that may be impacted by Brexit related delays. In the event of a supply disruption, Vermilion has developed contingency plans that include ensuring that the Company has maintained adequate inventory and has alternate sourcing plans from European Union ("EU") based suppliers.

The Company's day-to-day banking activities may also be impacted by Brexit for accounts based out of the United Kingdom, primarily relating to electronic payments through the EU based payment systems. Vermilion has reviewed its banking structure and has established alternate EU based bank accounts to minimize disruption.

Brexit has resulted in uncertainty and volatility for the Euro and GBP as compared to each other and other currencies. This volatility is expected to continue as negotiations continue. Vermilion's natural gas produced in Ireland is priced based on the NBP index, which is denominated in GBP. Thus, a weakening of the GBP against the Canadian dollar could result in Vermilion receiving fewer Canadian equivalent dollars for its production. However, due to the interconnected nature of United Kingdom and European natural gas markets, changes in the exchange ratio for the Euro and GBP are expected to result in offsetting changes to related commodity prices.

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, 2018.

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, 2018. 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 155.9 million boe (low estimate) to 334.1 million boe (high estimate), with a best estimate of 239.6 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 11.1 million boe (low estimate) to 52.9 million boe (high estimate), with a best estimate of 36.8 million boe.

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

Summary of risked oil and gas contingent resources as at December 31, 2018 (1) (2) - Forecast prices and costs (3) (4)

	Light & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE			Unrisked BOE	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Chance of Dev.	Gross	Net
Development Pending (10)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	% (9)	(Mboe)	(Mboe)
Contingent (1C) - Low Estimate													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	45,165	34,647	255,488	236,840	—	—	23,606	21,050	111,352	95,170	80%	138,951	117,839
CEE	—	—	2,992	2,843	—	—	—	—	499	474	90%	554	526
France	13,842	12,709	853	853	—	—	—	—	13,984	12,851	87%	16,127	14,819
Germany	—	—	21,171	18,324	—	—	—	—	3,529	3,054	78%	4,547	3,936
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	61	61	8,999	8,999	—	—	6	6	1,567	1,567	75%	2,080	2,080
USA	18,338	15,350	22,107	18,537	—	—	2,949	2,471	24,972	20,911	90%	27,746	23,234
Total	**77,406**	**62,767**	**311,610**	**286,396**	**—**	**—**	**26,561**	**23,527**	**155,903**	**134,027**	**82%**	**190,005**	**162,434**
Contingent (2C) - Best Estimate													
Australia (11)	2,440	2,440	—	—	—	—	—	—	2,440	2,440	80%	3,050	3,050
Canada (12)	63,010	48,949	398,080	366,947	—	—	34,531	30,156	163,898	140,263	80%	205,888	175,194
CEE	—	—	6,754	6,417	—	—	—	—	1,126	1,070	90%	1,251	1,188
France (13)	27,538	25,230	1,117	1,117	—	—	—	—	27,724	25,416	85%	32,636	29,912
Germany (14)	—	—	36,736	31,786	—	—	—	—	6,123	5,298	78%	7,890	6,827
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands (15)	121	121	19,681	19,681	—	—	14	14	3,416	3,415	75%	4,532	4,532
USA (16)	25,530	21,367	30,991	25,980	—	—	4,179	3,501	34,874	29,198	90%	38,749	32,442
Total	**118,639**	**98,107**	**493,359**	**451,928**	**—**	**—**	**38,724**	**33,671**	**239,600**	**207,100**	**81%**	**293,996**	**253,145**
Contingent (3C) - High Estimate													
Australia	3,280	3,280	—	—	—	—	—	—	3,280	3,280	80%	4,100	4,100
Canada	81,417	62,429	547,603	502,792	—	—	47,106	40,328	219,790	186,556	79%	277,233	234,018
CEE	—	—	12,825	12,184	—	—	—	—	2,138	2,031	90%	2,375	2,256
France	42,811	39,225	1,463	1,463	—	—	—	—	43,055	39,469	84%	51,122	46,853
Germany	—	—	67,865	58,710	—	—	—	—	11,311	9,785	78%	14,576	12,609
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	242	242	36,683	36,683	—	—	26	26	6,382	6,382	76%	8,362	8,362
USA	35,238	29,484	42,607	35,703	—	—	5,840	4,891	48,179	40,326	90%	53,532	44,806
Total	**162,988**	**134,660**	**709,046**	**647,535**	**—**	**—**	**52,972**	**45,245**	**334,135**	**287,829**	**81%**	**411,300**	**353,004**

Development Unclarified [17]	Light & Medium Crude Oil Gross (Mbbl)	Light & Medium Crude Oil Net (Mbbl)	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)	Coal Bed Methane Gross (MMcf)	Coal Bed Methane Net (MMcf)	Natural Gas Liquids Gross (Mbbl)	Natural Gas Liquids Net (Mbbl)	BOE Gross (Mboe)	BOE Net (Mboe)	Chance of Dev. % [9]	Unrisked BOE Gross (Mbbl)	Unrisked BOE Net (Mbbl)
Contingent (1C) - Low Estimate													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	3,375	3,111	27,384	24,893	—	—	521	437	8,460	7,697	59%	14,292	13,024
CEE	—	—	—	—	—	—	—	—	—	—	—%	—	—
France	1,511	1,411	—	—	—	—	—	—	1,511	1,411	42%	3,560	3,327
Germany	—	—	—	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	6,560	6,384	—	—	10	5	1,103	1,069	50%	2,201	2,115
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**4,886**	**4,522**	**33,944**	**31,277**	**—**	**—**	**531**	**442**	**11,074**	**10,177**	**55%**	**20,053**	**18,466**
Contingent (2C) - Best Estimate													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada [18]	4,176	3,840	57,594	52,009	60,886	57,602	6,682	5,987	30,604	28,096	47%	65,022	59,932
CEE	—	—	—	—	—	—	—	—	—	—	—%		—
France [19]	2,539	2,370	—	—	—	—	—	—	2,539	2,370	45%	5,690	5,315
Germany	—	—	1,496	1,190	—	—	—	—	249	198	35%	712	566
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands [20]	—	—	20,129	19,556	—	—	32	16	3,386	3,275	50%	6,738	6,460
USA	—	—	—	—	—	—	—	—	—	—	—		—
Total	**6,715**	**6,210**	**79,219**	**72,755**	**60,886**	**57,602**	**6,714**	**6,003**	**36,779**	**33,939**	**47%**	**78,162**	**72,273**
Contingent (3C) - High Estimate													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	5,103	4,685	84,733	75,937	77,410	72,422	10,419	8,910	42,546	38,322	47%	90,427	81,628
CEE	—	—	—	—	—	—	—	—	—	—	—%		—
France	3,825	3,570	—	—	—	—	—	—	3,825	3,570	46%	8,250	7,704
Germany	—	—	2,328	1,850	—	—	—	—	388	308	35%	1,108	881
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	36,811	35,933	—	—	48	24	6,183	6,013	53%	11,630	11,203
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**8,928**	**8,255**	**123,872**	**113,720**	**77,410**	**72,422**	**10,467**	**8,934**	**52,942**	**48,213**	**48%**	**111,415**	**101,416**

Summary of risked net present value of future net revenues as at December 31, 2018 - Forecast prices and costs [3]

(M$)	Before Income Taxes, Discounted at [5]					After Income Taxes, Discounted at [5]				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Contingent (1C) - Low Estimate [6]										
Development Pending [10]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	2,609,278	1,329,391	727,858	419,031	249,407	1,889,261	930,802	485,761	261,440	141,221
CEE	11,548	8,353	5,980	4,181	2,790	6,592	4,122	2,305	941	—
France	672,376	387,652	234,513	146,564	93,613	499,437	274,227	156,343	90,469	51,990
Germany	24,358	13,719	4,826	—	—	12,922	4,465	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	58,838	38,313	25,746	17,798	12,585	31,190	19,358	11,998	7,367	4,383
USA	920,819	458,308	248,019	142,874	86,219	724,812	361,077	195,012	111,932	67,208
Total	**4,297,217**	**2,235,736**	**1,246,942**	**730,448**	**444,614**	**3,164,214**	**1,594,051**	**851,419**	**472,149**	**264,802**
Contingent (2C) - Best Estimate [7]										
Development Pending [10]										
Australia [11]	102,296	67,433	44,873	30,129	20,378	27,895	15,145	7,471	2,911	246
Canada [12]	4,106,431	2,085,834	1,160,177	687,653	426,099	2,982,926	1,476,369	791,281	446,434	259,217
CEE	42,376	33,043	26,441	21,593	17,916	24,494	18,378	14,066	10,917	8,545
France [13]	1,470,151	825,326	497,201	315,174	207,677	1,091,706	588,240	338,641	203,847	126,472
Germany [14]	131,556	100,380	76,561	58,585	44,954	86,257	64,124	46,789	33,615	23,640
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [15]	138,133	88,893	60,069	42,235	30,642	74,271	45,380	28,539	18,310	11,839
USA [16]	1,532,938	736,149	397,407	232,493	143,967	1,208,132	580,891	313,407	183,125	113,213
Total	**7,523,881**	**3,937,058**	**2,262,729**	**1,387,862**	**891,633**	**5,495,681**	**2,788,527**	**1,540,194**	**899,159**	**543,172**
Contingent (3C) - High Estimate [8]										
Development Pending [10]										
Australia	187,273	126,252	86,715	60,646	43,136	66,431	41,477	25,990	16,287	10,141
Canada	6,054,223	2,903,319	1,594,930	954,303	604,510	4,396,438	2,071,436	1,106,933	639,072	387,326
CEE	93,627	74,963	61,818	52,153	44,792	54,219	42,710	34,614	28,677	24,170
France	2,525,265	1,413,668	860,710	555,006	373,209	1,872,950	1,015,326	596,708	369,872	237,717
Germany	345,559	267,546	211,244	170,044	139,249	232,114	178,327	138,804	109,729	88,005
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	305,666	198,187	137,102	99,590	75,071	164,990	104,196	69,689	48,718	35,214
USA	2,422,296	1,096,196	581,036	339,724	211,959	1,910,130	865,435	458,660	268,044	167,134
Total	**11,933,909**	**6,080,131**	**3,533,555**	**2,231,466**	**1,491,926**	**8,697,272**	**4,318,907**	**2,431,398**	**1,480,399**	**949,707**
Contingent (1C) - Low Estimate [6]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	142,700	71,708	38,903	22,444	13,592	111,676	54,413	28,227	15,458	8,769
CEE	—	—	—	—	—	—	—	—	—	—
France	100,902	56,931	33,664	20,695	13,135	72,213	39,750	22,824	13,567	8,287
Germany	—	—	—	—	—	—	—	—	—	—
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	25,648	16,266	10,200	6,270	3,685	14,668	8,523	4,526	1,978	352
USA	—	—	—	—	—	—	—	—	—	—
Total	**269,250**	**144,905**	**82,767**	**49,409**	**30,412**	**198,557**	**102,686**	**55,577**	**31,003**	**17,408**
Contingent (2C) - Best Estimate [7]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada [18]	507,086	244,914	121,056	57,853	23,630	363,555	166,983	74,360	27,672	2,958
CEE	—	—	—	—	—	—	—	—	—	—
France [19]	183,229	96,765	54,848	32,822	20,476	131,935	68,328	37,771	21,955	13,253
Germany [20]	1,688	1,852	1,765	1,585	1,382	401	707	738	658	540
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [21]	112,844	70,393	45,535	30,356	20,676	64,337	38,270	22,966	13,743	7,983
USA	—	—	—	—	—	—	—	—	—	—
Total	**804,847**	**413,924**	**223,204**	**122,616**	**66,164**	**560,228**	**274,288**	**135,835**	**64,028**	**24,734**
Contingent (3C) - High Estimate [8]										
Development Unclarified [17]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	881,032	436,173	238,574	139,227	84,305	627,843	302,743	157,838	85,474	46,062
CEE	—	—	—	—	—	—	—	—	—	—
France	296,806	146,180	80,023	47,088	29,162	214,960	104,225	55,864	32,089	19,352
Germany	6,219	5,668	4,974	4,305	3,714	3,569	3,396	2,998	2,567	2,169
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	263,515	151,869	96,052	64,867	45,934	153,076	84,985	51,307	32,805	21,792
USA	—	—	—	—	—	—	—	—	—	—
Total	**1,447,572**	**739,890**	**419,623**	**255,487**	**163,115**	**999,448**	**495,349**	**268,007**	**152,935**	**89,375**

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 uncertainty 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 2018 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See ”Forecast Prices Used in Estimates” in this AIF.

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

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

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

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

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

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

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

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

(11) Risked development pending best estimate contingent resources for Australia have been estimated based on the continued drilling in our active core asset (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $133 MM and the expected timeline is between 6 and 8 years. The specific contingencies for these resources are corporate commitment and development timing.

(12) Risked development pending best estimate contingent resources for Canada have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $1,927 MM and the expected timeline is between 3 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(13) Risked development pending best estimate contingent resources for France have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $605 MM and the expected timeline is between 3 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(14) Risked development pending best estimate contingent resources for Germany have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $100 MM and the expected timeline is between 2 and 4 years. The specific contingencies for these resources are corporate commitment and development timing.

(15) Risked development pending best estimate contingent resources for Netherlands have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $51 MM and the expected timeline is between 2 and 4 years. The specific contingencies for these resources are corporate commitment and development timing.

(16) Risked development pending best estimate contingent resources for USA have been estimated based on the continued drilling in our active core asset (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $391 MM and the expected timeline is between 1 and 11 years. The specific contingencies for these resources are corporate commitment and development timing.

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

(18) In Canada, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 31 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 $401 MM with an expected timeline of 4 to 10 years.

Edson Duvernay	Based on contingencies related to corporate commitment and development timing, economic risks associated with lower liquid yields, and capital and operating cost uncertainty, GLJ has estimated risked unclarified best estimate contingent resources at 15.5 mmboe and the risked estimated cost to bring these resources on commercial production is $238 MM. The expected timeline is 3 to 7 years.
Ferrier Notikewin	Based on contingencies related to corporate commitment and development timing that is greater than 10 years, GLJ has estimated risked unclarified best estimate contingent resources at 4.2 mmboe and the risked estimated cost to bring these resources on commercial production is $29 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 2.7 mmboe and the risked estimated cost to bring these resources on commercial production is $21 MM. The expected timeline is 11 to 15 years.
West Pembina Glauconite	Based on contingencies related to corporate commitment and development timing as well as economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands, GLJ has estimated risked unclarified best estimate contingent resources at 3.7 mmboe and the risked estimated cost to bring these resources on commercial production is $28 MM. The expected timeline is 4 to 6 years.
Saskatchewan	Based on contingencies related to corporate commitment and development timing, GLJ has estimated risked unclarified best estimate contingent resources at 4.4 mmboe and the risked estimated cost to bring these resources on commercial production is $86 MM. The expected timeline is 4 to 6 years.

(19) In France, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 2.5 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $39 MM with an expected timeline of 7 to 8 years.

Charmottes	Based on contingencies related to corporate commitment and development timing, along with the project still being in the pre-development study/sourcing stage related to waterflood development, GLJ has estimated risked unclarified best estimate contingent resources at 1.3 mmboe and the risked estimated cost to bring these resources on commercial production is $32 MM. The expected timeline is 7 to 9 years.
Chaunoy	Based on contingencies related to corporate commitment and development timing, along with a CO2 pilot project still being in the conceptual study stage, GLJ has estimated risked unclarified best estimate contingent resources at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM. The expected timeline is 8 to 10 years.

(20) In Germany, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of .25 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 $4.5 MM with an expected timeline of 8 to 10 years.

Germany	Based on contingencies related to corporate commitment and development timing, along with project being near residences and may not be permitted, GLJ has estimated risked unclarified best estimate contingent resources at 0.25 mmboe and the risked estimated cost to bring these resources on commercial production is $4.5 MM. The expected timeline is 8 to 10 years.

(21) In the Netherlands, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 3.4 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 $55 MM with an expected timeline of 8 to 10 years.

Netherlands East	Based on contingencies related to corporate commitment and development timing along with proof-of-concept utilizing directional drilling and unknown deliverability from Zechstein carbonates, GLJ has estimated risked unclarified best estimate contingent resources at 1.8 mmboe and the risked estimated cost to bring these resources on commercial production is $29 MM. The expected timeline is 3 to 7 years.
Netherlands West	Based on contingencies related to corporate commitment and development timing along with further study required regarding the deliverability of the Bunter sands, GLJ has estimated risked unclarified best estimate contingent resources at 1.6 mmboe and the risked estimated cost to bring these resources on commercial production is $26 MM. The expected timeline is 3 to 5 years.

Prospective resources

Summary information regarding prospective resources and net present value of future net revenues from prospective resources are set forth below and are derived, in each case, from the GLJ Resources Assessment. The GLJ Resources Assessment was prepared in accordance with COGEH and NI 51-101 by GLJ, an independent qualified reserve evaluator. All prospective resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2018. 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 55.0 million boe (low estimate) to 283.9 million boe (high estimate), with a best estimate of 161.1 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, 2018 (1) (2) - Forecast prices and costs (3) (4)

	Light & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE			Unrisked BOE	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Chance of Commerciality	Gross	Net
Prospect [10]	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	% [9]	(Mboe)	(Mboe)
Prospective (Pr1) - Low Estimate													
Australia	—	—	—	—	—	—	—	—	—	—	—	—	—
Canada	496	475	72,910	67,539	—	—	5,023	4,358	17,671	16,090	33%	52,918	48,096
CEE	287	235	6,318	5,574	—	—	—	—	1,340	1,164	44%	3,026	2,563
France	2,928	2,766	—	—	—	—	—	—	2,928	2,766	41%	7,117	6,703
Germany	—	—	146,328	125,748	—	—	—	—	24,388	20,958	30%	81,205	69,784
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	—	—	51,770	47,096	—	—	56	51	8,684	7,900	11%	81,927	74,418
USA	—	—	—	—	—	—	—	—	—	—	—		—
Total	**3,711**	**3,476**	**277,326**	**245,957**	**—**	**—**	**5,079**	**4,409**	**55,011**	**48,878**	**24%**	**226,193**	**201,564**
Prospective (Pr2) - Best Estimate													
Australia [11]	545	545	—	—	—	—	—	—	545	545	48%	1,136	1,136
Canada [12]	2,382	2,144	166,384	151,529	112,623	106,141	25,149	21,983	74,033	67,072	24%	313,803	286,142
CEE [13]	1,011	825	15,377	13,673	21,228	20,804	—	—	7,112	6,571	32%	22,306	20,802
France [14]	11,647	10,610	—	—	—	—	—	—	11,647	10,610	32%	35,973	32,316
Germany [15]	—	—	312,945	270,106	—	—	—	—	52,157	45,018	30%	173,668	149,895
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands [16]	58	58	92,826	85,132	—	—	100	92	15,629	14,339	11%	146,919	134,560
USA	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**15,643**	**14,182**	**587,532**	**520,440**	**133,851**	**126,945**	**25,249**	**22,075**	**161,124**	**144,155**	**23%**	**693,805**	**624,851**
Prospective (Pr3) - High Estimate													
Australia	1,225	1,225	—	—	—	—	—	—	1,225	1,225	48%	2,553	2,553
Canada	3,064	2,735	251,301	227,508	147,282	136,627	38,887	32,570	108,382	95,994	24%	450,545	399,428
CEE	3,023	2,467	35,169	31,135	50,732	49,718	—	—	17,340	15,943	32%	54,235	50,411
France	27,563	25,288	—	—	—	—	—	—	27,563	25,288	33%	83,427	75,303
Germany	—	—	605,388	524,609	—	—	—	—	100,898	87,435	30%	335,959	291,131
Ireland	—	—	—	—	—	—	—	—	—	—	—	—	—
Netherlands	278	278	168,019	156,101	—	—	178	166	28,459	26,461	11%	266,958	247,814
USA	—	—	—	—	—	—	—	—	—	—	—		—
Total	**35,153**	**31,993**	**1,059,877**	**939,353**	**198,014**	**186,345**	**39,065**	**32,736**	**283,867**	**252,346**	**24%**	**1,193,677**	**1,066,640**

Summary of risked net present value of future net revenues as at December 31, 2018 - Forecast prices and costs (3)

	Before Income Taxes, Discounted at (5)					After Income Taxes, Discounted at (5)				
(M$)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Prospective (Pr1) - Low Estimate (6)										
Prospect (10)										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	266,350	109,607	45,302	17,618	5,360	208,881	81,819	30,554	9,199	271
CEE	42,928	33,783	27,043	21,948	18,009	24,793	18,954	14,635	11,370	8,851
France	107,921	54,794	27,922	14,100	6,881	79,812	37,619	16,996	6,895	1,974
Germany	355,903	185,873	92,506	42,979	16,609	220,108	114,530	52,197	18,816	1,394
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	310,998	127,168	62,458	34,684	20,944	162,720	59,286	23,302	8,932	2,597
USA	—	—	—	—	—	—	—	—	—	—
Total	**1,084,100**	**511,225**	**255,231**	**131,329**	**67,803**	**696,314**	**312,208**	**137,684**	**55,212**	**15,087**
Prospective (Pr2) - Best Estimate (7)										
Prospect (10)										
Australia (11)	39,910	25,906	17,231	11,718	8,131	15,344	9,598	6,138	4,006	2,663
Canada (12)	1,618,734	672,710	299,611	139,132	65,388	1,105,564	441,118	181,974	73,767	26,504
CEE (13)	233,540	151,268	105,931	78,540	60,711	143,407	90,221	60,645	42,916	31,549
France (14)	505,977	276,333	160,707	98,813	63,810	359,498	187,590	104,119	61,133	37,774
Germany (15)	1,291,453	614,294	310,803	164,315	88,808	866,639	408,025	199,822	99,748	48,870
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands (16)	720,421	324,255	178,670	111,198	74,904	388,672	167,340	86,719	50,496	31,777
USA	—	—	—	—	—	—	—	—	—	—
Total	**4,410,035**	**2,064,766**	**1,072,953**	**603,716**	**361,752**	**2,879,124**	**1,303,892**	**639,417**	**332,066**	**179,137**
Prospective (Pr3) - High Estimate (8)										
Prospect (10)										
Australia	110,781	72,433	48,635	33,437	23,477	45,111	29,139	19,328	13,128	9,108
Canada	2,875,591	1,183,067	552,413	281,299	152,052	1,939,285	773,728	344,712	164,634	81,701
CEE	783,873	443,197	294,099	213,886	164,981	470,411	261,951	170,555	121,700	92,202
France	1,618,006	851,442	485,029	294,910	189,263	1,206,296	619,597	345,071	205,561	129,546
Germany	2,971,036	1,397,355	712,919	385,710	217,200	2,014,938	938,404	468,873	245,546	131,720
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	1,501,384	707,929	407,060	262,522	182,166	817,973	377,967	211,981	133,414	90,501
USA	—	—	—	—	—	—	—	—	—	—
Total	**9,860,671**	**4,655,423**	**2,500,155**	**1,471,764**	**929,139**	**6,494,014**	**3,000,786**	**1,560,520**	**883,983**	**534,778**

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 2018 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See "GLJ December 31, 2018 Forecast Prices" in this AIF.

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

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

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

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

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

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

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

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

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

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

- Reservoir - For a significant accumulation of potentially recoverable petroleum, a reservoir rock must be present and have sufficient porosity and permeability and be of a sufficient thickness to produce quantities of mobile hydrocarbon. Under this approach, encountering wet, commercial quality and quantity sandstones would not be a failure in the reservoir category, but rather in one of the other factors. It is the reservoir along with the trap which determine the volumetrics of the accumulation.
- Serial multiplication of these five decimal fractions representing the five geologic chance factors can be done as they are considered independent of each other.

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

(11) Prospective resources for Australia have been estimated based on development timing and reservoir risk, GLJ has estimated the CoDev at 80% and the CoDis at 60%. The corresponding chance of commerciality is 48%. Risked best estimate prospective resources have been estimated at 0.5 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is $16 MM. The expected development timeline is 7 years.

(12) Prospective resources for Canada have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 27% and the aggregate CoDis at 88%. The corresponding chance of commerciality is 23%. Risked best estimate prospective resources have been estimated at an aggregate of 74.0 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $1061 MM. The expected development timeline is 2 to 20 years.

Edson Duvernay	Based on reservoir risk, development timing and economic risk related to capital and operating cost uncertainty, GLJ has estimated the CoDev at 19% and the CoDis at 90%. The corresponding chance of commerciality is 17%. Risked best estimate prospective resources have been estimated at 33.6 mmboe and the risked estimated cost to bring these resources on commercial production is $625 MM with an expected timeline of 7 to 14 years.
Wilrich Prospect:	Based on reservoir risk, development timing and limited Wilrich development on the land base, GLJ has estimated the CoDev at 35% and the CoDis at 85%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 23.0 mmboe and the risked estimated cost to bring these resources on commercial production is $246 MM with an expected timeline of 6 to 13 years.
West Pembina Glauconite Prospect:	Based on chance of discovery risk due to uncertainty regarding threshold for reservoir quality to support commercial development of resources with horizontal drilling, along with economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands and chance of development risk related to corporate commitment and development timing. GLJ has estimated the CoDev at 34% and the CoDis at 90%. The corresponding chance of commerciality is 31%. Risked best estimate prospective resources have been estimated at 6.5 mmboe and the risked estimated cost to bring these resources on commercial production is $53 MM with an expected timeline of 6 to 12 years.
Drayton Valley Notikewin Prospect:	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 85%. The corresponding chance of commerciality is 60%. Risked best estimate prospective resources have been estimated at 4.6 mmboe and the risked estimated cost to bring these resources on commercial production is $66 MM. The expected development timeline is 9 to 11 years.
Saskatchewan Prospects	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 90% and the CoDis at 80%. The corresponding chance of commerciality is 72%. Risked best estimate prospective resources have been estimated at 3.5 mmboe and the risked estimated cost to bring these resources on commercial production is $69 MM with an expected timeline of 2 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 2.7 mmboe and the risked estimated cost to bring these resources on commercial production is $24 MM with an expected timeline of 14 to 20 years.
Utikuma Gilwood Prospect	Based on reservoir risk, development timing and limited Gilwood development in the area, GLJ has estimated the CoDev at 60% and the CoDis at 50%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $3 MM with an expected timeline of 4 to 10 years.

(13) Prospective resources for CEE have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 85% and the aggregate CoDis at 56%. The corresponding chance of commerciality is 48%. Risked best estimate prospective resources have been estimated at an aggregate of 7 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $101 MM. The expected development timeline is 1 to 2 years.

Croatia Prospect	Based on risks associated with development timing and discover risk, GLJ has estimated the CoDev at 90% and the CoDis at 56%. The corresponding chance of commerciality is 50%. Risked best estimate prospective resources have been estimated at 1.3 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM with an expected timeline of 2 years.
Hungary Prospect	Based on risks associated with development timing and discover risk, GLJ has estimated the CoDev at 75% and the CoDis at 33%. The corresponding chance of commerciality is 25%. Risked best estimate prospective resources have been estimated at 4.4 mmboe and the risked estimated cost to bring these resources on commercial production is $88 MM with an expected timeline of 2 years.
Slovakia Prospect	Based on risks associated with development timing and discover risk, GLJ has estimated the CoDev at 90% and the CoDis at 78%. The corresponding chance of commerciality is 70%. Risked best estimate prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $6 MM with an expected timeline of 1 year.

(14) Prospective resources for France have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 68% and the aggregate CoDis at 48%. The corresponding chance of commerciality is 33%. Risked best estimate prospective resources have been estimated at an aggregate of 11.6. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $378 MM. The expected development timeline is 1 to 13 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 $229 MM with an expected timeline of 8 to 12 years.
Seebach Prospect	Based on risks associated with seal, trap, reservoir and charge along with development timing, GLJ has estimated the CoDev at 65% and the CoDis at 32%. The corresponding chance of commerciality is 21%. Risked best estimate prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $17 MM with an expected timeline of 8 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 1.3 mmboe and the risked estimated cost to bring these resources on commercial production is $34 MM with an expected timeline of 8 to 14 years.
West Lavergne Prospect	Based on structure risk and development timing GLJ has estimated the CoDev at 80% and the CoDis at 70%. The corresponding chance of commerciality is 56%. Risked best estimate prospective resources have been estimated at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM with an expected timeline of 3 years.
Champotran Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 80% and the CoDis at 64%. The corresponding chance of commerciality is 54%. 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 $20 MM with an expected timeline of 8 to 12 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 0.5 mmboe and the risked estimated cost to bring these resources on commercial production is $14 MM with an expected timeline of 6 to 8 years.
Phobos Prospect	Based on reservoir and closure risk along with 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 $24 MM with an expected timeline of 7 to 8 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 $20 MM with an expected timeline of 9 to 11 years.
Bernet Prospect	Based on risks associated with reservoir, seal and trap along with economic factors, and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 65%. The corresponding chance of commerciality is 33%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM with an expected timeline of 3 to 4 years.
Vert Le Grand Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 28%. The corresponding chance of commerciality is 20%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $4 MM with an expected timeline of 4 to 5 years.
Les Genets Prospect	Based on reservoir, seal and closure risk, along with economic factors and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 16%. The corresponding chance of commerciality is 10%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $1 MM with an expected timeline of 7 years.
North Acacias Prospect	Based on reservoir, seal and trap risk, along with economic factors and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 39%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 0.07 mmboe and the risked estimated cost to bring these resources on commercial production is $1 MM with an expected timeline of 3 to 4 years.

(15) Prospective resources for Germany have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 69% and the aggregate CoDis at 43%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at an aggregate of 52.2 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of 339.5 MM. The expected development timeline is 1 to 12 years.

Wisselshorst A Prospect	Based on seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 58%. The corresponding chance of commerciality is 52%.Risked Best Estimate Prospective resources have been estimated at 14.4 mmboe and the risked estimated cost to bring these resources on commercial production is $92.2MM with an expected timeline of 2 to 9 years.
Ihlow Prospect	Based on reservoir, seal and trap risk along with development timing,, GLJ has estimated the CoDev at 71%, and the CoDisc at 51%. The corresponding chance of commerciality is 36%.Risked Best Estimate Prospective resources have been estimated at 7.9 mmboe and the risked estimated cost to bring these resources on commercial production is $55.3MM with an expected timeline of 4 to 6 years.
Wisselshorst B Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 50%. The corresponding chance of commerciality is 45%.Risked Best Estimate Prospective resources have been estimated at 5.9 mmboe and the risked estimated cost to bring these resources on commercial production is $45.2MM with an expected timeline of 4 to 11 years.
Weissenmoor South	Based on reservoir and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 64%. The corresponding chance of commerciality is 57%.Risked Best Estimate Prospective resources have been estimated at 3 mmboe and the risked estimated cost to bring these resources on commercial production is $19.3MM with an expected timeline of 2 to 4 years.
Simonswolde South Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 71%, and the CoDisc at 48%. The corresponding chance of commerciality is 34%.Risked Best Estimate Prospective resources have been estimated at 4.9 mmboe and the risked estimated cost to bring these resources on commercial production is $19MM with an expected timeline of 7 to 8 years.
Fallingbostel	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 29%. The corresponding chance of commerciality is 26%.Risked Best Estimate Prospective resources have been estimated at 3.4 mmboe and the risked estimated cost to bring these resources on commercial production is $29.7MM with an expected timeline of 3 to 9 years.
Hellwege	Based on reservoir and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 40%. The corresponding chance of commerciality is 36%.Risked Best Estimate Prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $16.2MM with an expected timeline of 3 to 8 years.
Jeddeloh Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 38%, and the CoDisc at 32%. The corresponding chance of commerciality is 12%.Risked Best Estimate Prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $23.3MM with an expected timeline of 3 to 12 years.
Ohlendorf Prospect	Based on source and trap risk along with development timing, GLJ has estimated the CoDev at 58%, and the CoDisc at 30%. The corresponding chance of commerciality is 17%.Risked Best Estimate Prospective resources have been estimated at 2.4 mmboe and the risked estimated cost to bring these resources on commercial production is $11MM with an expected timeline of 8 to 12 years.
Uphuser Meer Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 47%, and the CoDisc at 51%. The corresponding chance of commerciality is 24%.Risked Best Estimate Prospective resources have been estimated at 2 mmboe and the risked estimated cost to bring these resources on commercial production is $9.9MM with an expected timeline of 5 to 6 years.
Simonswolde North Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 62%, and the CoDisc at 45%. The corresponding chance of commerciality is 28%.Risked Best Estimate Prospective resources have been estimated at 1.7 mmboe and the risked estimated cost to bring these resources on commercial production is $7.3MM with an expected timeline of 5 to 6 years.
Burgmoor Z5 Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 63%, and the CoDisc at 52%. The corresponding chance of commerciality is 33%.Risked Best Estimate Prospective resources have been estimated at 1.3 mmboe and the risked estimated cost to bring these resources on commercial production is $2.8MM with an expected timeline of 1 year.
Ostenholz West Prospect	Based on reservoir, seal and trap risk along with development timing,, GLJ has estimated the CoDev at 90%, and the CoDisc at 22%. The corresponding chance of commerciality is 20%.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 $3.2MM with an expected timeline of 5 to 6 years.
Widdernhausen East Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDisc at 44%. The corresponding chance of commerciality is 14%.Risked Best Estimate Prospective resources have been estimated at 0.4 mmboe and the risked estimated cost to bring these resources on commercial production is $2.6MM with an expected timeline of 7 to 11 years.
Wellie Prospect	Based on reservoir, seal and source risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDisc at 20%. The corresponding chance of commerciality is 6%.Risked Best Estimate Prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3.4MM with an expected timeline of 9 years.

Otterstedt Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 46%, and the CoDisc at 34%. The corresponding chance of commerciality is 16%.Risked Best Estimate Prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3.4MM with an expected timeline of 8 to 12 years.
Ostervesede Prospect	Based on reservoir and seal risk along with development timing, GLJ has estimated the CoDev at 23%, and the CoDisc at 25%. The corresponding chance of commerciality is 6%.Risked Best Estimate Prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $0.7MM with an expected timeline of 7 to 9 years.

(16) Prospective resources for Netherlands have been estimated based on the factors outlined below. GLJ has estimated the aggregate CoDev at 28% and the aggregate CoDis at 39%. The corresponding chance of commerciality is 11%. Risked best estimate prospective resources have been estimated at an aggregate of 15.6 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of 145 MM with an expected timeline of 2 to 15 years.

Prospective resources for Netherlands East have been estimated based on the individual areas outlined below. GLJ has estimated the aggregate CoDev at 27% and the aggregate CoDis at 41%. The corresponding chance of commerciality is 11%. Risked best estimate prospective resources have been estimated at an aggregate of 12.6 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of 99 MM with an expected timeline of 2 to 14 years.

- Chance of discovery provided for 117 prospective reservoir targets across 95 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.
- 70 prospects summed probabilistically across 14 development groups to appropriately allocate required infrastructure capital across multiple prospective targets within reasonable proximity. As probabilistic summation of the groups resulted in strong economic indicators, no further minimum economic field size calculations were applied as they were considered to have nominal impact.

Prospective resources for Netherlands West have been estimated based on the factors outlined below. GLJ has estimated the aggregate CoDev at 41% and the aggregate CoDis at 28%. The corresponding chance of commerciality is 12%. Risked best estimate prospective resources have been estimated at an aggregate of 3.0 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of$ 46 MM with an expected timeline of 2 to 12 years.

- Chance of discovery provided for 35 prospective reservoir targets across 29 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.
- 25 prospects summed probabilistically across 8 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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, 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 2018, 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, 2018	Australia	—	308,956	—	308,956
GLJ Petroleum Consultants	December 31, 2018	Canada	—	3,843,590	—	3,843,590
GLJ Petroleum Consultants	December 31, 2018	France	—	1,732,561	—	1,732,561
GLJ Petroleum Consultants	December 31, 2018	Germany	—	472,948	—	472,948
GLJ Petroleum Consultants	December 31, 2018	Hungary	—	6,802	—	6,802
GLJ Petroleum Consultants	December 31, 2018	Ireland	—	574,544	—	574,544
GLJ Petroleum Consultants	December 31, 2018	Netherlands	—	543,764	—	543,764
GLJ Petroleum Consultants	December 31, 2018	USA	—	716,929	—	716,929
Total			**—**	**8,200,094**	**—**	**8,200,094**

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 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 7, 2019

"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, 2018. 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, 2018, 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

			Location of Resources Other than Reserves		Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$)		
Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	(Country or Foreign Geographic Area)	Risked Volume (Mboe)	Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	Australia	2,440	—	44,873	44,873
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	Canada	163,898	—	1,160,177	1,160,177
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	CEE	1,126	—	26,441	26,441
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	France	27,724	—	497,201	497,201
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	Germany	6,123	—	76,561	76,561
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	Netherlands	3,416	—	60,069	60,069
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	USA	34,874	—	397,407	397,407
Total				**239,600**	**—**	**2,262,729**	**2,262,729**

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	(Country or Foreign Geographic Area)	Risked Volume (Mboe)
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	Canada	30,604
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	France	2,539
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	Germany	249
Development Unclarified Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 2018	Netherlands	3,386
Total				**36,779**

Prospective Resources

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	(Country or Foreign Geographic Area)	Risked Volume (Mboe)
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2018	Australia	545
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2018	Canada	74,033
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2018	CEE	7,112
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2018	France	11,647
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2018	Germany	52,157
Prospect Prospective Resources	GLJ Petroleum Consultants	December 31, 2018	Netherlands	15,629
Total				**161,124**

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 7, 2019

"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, 2018, 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 Appendix A to the Annual Information Form of the Company for the year ended December 31, 2018.

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 judgments regarding future events, actual results will vary and the variations may be material.

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

"Lars Glemser"
Lars Glemser, Vice President and Chief Financial Officer

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

"William Roby"
William Roby, Director

February 27, 2019

Appendix D

Terms of reference for the Audit Committee

I. PURPOSE

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

A. the integrity of the Company's financial statements;
B. the Company's compliance with legal and regulatory requirements;
C. the independent auditors' qualifications and independence;
D. the financial information that will be provided to the Shareholders and others;
E. the Company's systems of disclosure controls and internal controls regarding finance, accounting, legal compliance and ethics, which management and the Board have established;
F. the performance of the Company's audit processes; and
G. such other matters required by applicable laws and rules of any stock exchange on which the Company's shares are listed for trading.

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

II. COMPOSITION AND OPERATIONS

A. The Committee shall be composed of not fewer than three directors and not more than five directors, all of whom are "independent"[1] under the requirements or guidelines for audit committee service under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading.
B. All Committee members shall be "financially literate,"[2] and at least one member shall have "accounting or related financial expertise" as such terms are interpreted by the Board in its business judgment in light of, and in accordance with, the requirements or guidelines for audit committee service under applicable securities laws and rules of any stock exchange on which the Company's shares are listed for trading. The Committee may include a member who is not financially literate, provided he or she attains this status within a reasonable period of time following his or her appointment and providing the Board has determined that including such member will not materially adversely affect the ability of the Committee to act independently.
C. No Committee member shall serve on the audit committees of more than two other public issuers without prior determination by the Board that such simultaneous service would not impair the ability of such member to serve effectively on the Committee.
D. The Committee shall operate in a manner that is consistent with the Committee Guidelines outlined in Tab 8 of the Board Manual.
E. The Company's auditors shall be advised of the names of the Committee members and will receive notice of and be invited to attend meetings of the Committee, and to be heard at those meetings on matters relating to the auditor's duties.
F. The Committee may request any officer or employee of the Company, or the Company's legal counsel, or any external or internal auditors to attend a meeting of the Committee to provide such pertinent information as the Committee requests or to meet with any members of, or consultants to the Committee. The Committee has the authority to communicate directly with the internal and external auditors as it deems appropriate to consider any matter that the Committee or auditors determine should be brought to the attention of the Board or Shareholders.
G. The Committee shall have the authority to select, retain, terminate and approve the fees and other retention terms of special independent legal counsel and other consultants or advisers to advise the Committee, as it deems necessary or appropriate, at the Company's expense.

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

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

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.

B. Risk Management, Internal Control and Information Systems

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

i) review the Company's risk management controls and policies with specific responsibility for Credit & Counterparty, Market & Financial, Political and Strategic & Repatriation risks;
ii) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through separate and periodic discussions with and reports from management, the internal auditor and external auditor; and
iii) review management steps to implement and maintain appropriate internal control procedures including a review of policies.

C. External Audit

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

i) review and recommend to the Board, for Shareholder approval, the appointment of the external auditor;
ii) review and approve the annual external audit plan, including but not limited to the following:
  a) engagement letter between the external auditor and financial management of the Company;
  b) objectives and scope of the external audit work;
  c) procedures for quarterly review of financial statements;
  d) materiality limit;
  e) areas of audit risk;
  f) staffing;
  g) timetable; and
  h) compensation and fees to be paid by the Company to the external auditor.
iii) meet with the external auditor to discuss the Company's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;
iv) maintain oversight of the external auditor's work and advise the Board, including but not limited to:
  a) the resolution of any disagreements between management and the external auditor regarding financial reporting;
  b) any significant accounting or financial reporting issue;
  c) the auditors' evaluation of the Company's system of internal controls, procedures and documentation;
  the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weaknesses;
  d) any other matters the external auditor brings to the Committee's attention; and
  e) evaluate and assess the qualifications and performance of the external auditors for recommendation to the Board as to the appointment or reappointment of the external auditor to be proposed for approval by the Shareholders, and ensuring that such auditors are participants in good standing pursuant to applicable regulatory laws.
v) review the auditor's report on all material subsidiaries;
vi) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Company and its affiliates in order to determine the external auditors' independence, including, without limitation:
  a) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors, including a list of all relationships between the external auditor and the Company that may reasonably be thought to bear on the independence of the external auditors with respect to the Company;
  b) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors; and
  c) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.
vii) annually request and review a report from the external auditor regarding (a) the external auditor's quality-control procedures, (b) any material issues raised by the most recent quality-control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental or professional authorities within the preceding five years respecting one or more independent audits carried out by the firm, and (c) any steps taken to deal with any such issues;
viii) review and pre-approve any non-audit services to be provided to the Company or any affiliates by the external auditor's firm or its affiliates (including estimated fees), and consider the impact on the independence of the external audit;
ix) review the disclosure with respect to its pre-approval of audit and non-audit services provided by the external auditors; and
x) meet periodically, and at least annually, with the external auditor without management present.

D. Compliance

The Committee shall:

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

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

iii) Assist the Governance and Human Resources Committee with preparing the Company's governance disclosure by ensuring it has current and accurate information on:

   a) the independence of each Committee member relative to regulatory requirements for audit committees;

   b) the state of financial literacy of each Committee member, including the name of any member(s) currently in the process of acquiring financial literacy and when they are expected to attain this status; and

   c) the education and experience of each Committee member relevant to his or her responsibilities as Committee member.

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

E. Other

The Committee shall:

i) establish and periodically review procedures for:

   a) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and

   b) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other matters that could negatively affect the Company, such as violations of the Code of Business Conduct and Ethics.

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

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

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

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

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

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

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

IV. ACCOUNTABILITY

A. 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.

B. 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.

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