FORM 40-F

Annual reports filed by certain Canadian issuers pursuant to Section 15(d) and Rule 15d-4

Filing Date: **2019-02-28** | Period of Report: **2018-12-31**
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FILER

VERMILION ENERGY INC.

CIK:**1293135**| IRS No.: **000000000** | State of Incorp.:**A0** | Fiscal Year End: **1231**
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SIC: **1311** Crude petroleum & natural gas

Mailing Address
3500, 520 - 3RD AVENUE S.W.
CALGARY A0 T2P 0R3

Business Address
3500, 520 - 3RD AVENUE S.W.
CALGARY A0 T2P 0R3
403-269-4884

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

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

For the fiscal year ended: December 31, 2018
Commission file number: No. 0-50832

Vermilion Energy Inc.

(Exact name of registrant as specified in its charter)
Alberta

(Province or other jurisdiction of incorporation or organization)
1311

(Primary standard industrial classification code number)
N/A

(I.R.S. employer identification number)
3500, 520 - 3rd Avenue S.W.
Calgary, Alberta T2P 0R3 Canada
(403) 269-4884

(Address and telephone number of registrant's principal executive office)
National Corporate Research, Ltd.
225 West 34th Street, Suite 910
New York, New York 10122 U.S.A.
(212) 947-7200

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

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

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

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

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

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

☑ **Annual Information Form** ☑ **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: **152,703,959 shares**

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

Yes	☑	No	☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes	☑	No	☐

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

Emerging growth company ☐

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

DOCUMENTS FILED PURSUANT TO GENERAL INSTRUCTIONS

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

Exhibit 99.1 - Annual Information Form for the fiscal year ended December 31, 2018
Exhibit 99.2 - Management's Discussion and Analysis for the fiscal year ended December 31, 2018; and
Exhibit 99.3 - Audited Annual Financial Statements for the fiscal year ended December 31, 2018

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

DISCLOSURE CONTROLS AND PROCEDURES

A. Evaluation of Disclosure Controls and Procedures

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

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

See page 3 of the 2018 Audited Consolidated Financial Statements included as Exhibit 99.3 to this report.

C. Auditor Attestation

See page 5 of the 2018 Audited Consolidated Financial Statements included as Exhibit 99.3 to this report.

D. Changes in Internal Control Over Financial Reporting

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

NOTICES REQUIRED BY RULE 104 OF REGULATION BTR

None

AUDIT COMMITTEE FINANCIAL EXPERT

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

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

CODE OF ETHICS

The Registrant has adopted a written “code of ethics” (as that term is defined in Form 40-F) that applies to its directors, officers and employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions. A copy of such code of ethics is available upon request or on the Registrant’s website at www.vermilionenergy.com. In 2018, there were no amendments to the code of ethics or waivers, including implicit waivers, from any provision of the code of ethics.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

See page 54 of the Annual Information Form for the year ended December 31, 2018 included as Exhibit 99.1 to this report.

The Audit Committee pre-approves all audit related fees. The auditors present the estimate for the annual audit related services to the Audit Committee for approval prior to undertaking the annual audit of the financial statements.

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

OFF-BALANCE SHEET ARRANGEMENTS

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

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

Payments due by period as at December 31, 2018 (Cdn $000's)

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt (1)	78,604	157,208	1,435,616	443,791	2,115,219
Lease obligations	30,798	49,743	34,313	42,739	157,593
Processing and transportation agreements	25,844	24,835	10,902	34,371	95,952
Purchase obligations	33,223	16,223	1,379	—	50,825
Drilling and service agreements	26,667	28,933	41,976	5,301	102,877
Total contractual obligations and commitments	195,136	276,942	1,524,186	526,202	2,522,466

IDENTIFICATION OF THE AUDIT COMMITTEE

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

NYSE STATEMENT OF GOVERNANCE DIFFERENCES

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

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

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

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

B. Consent to Service of Process

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

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

SIGNATURES

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

VERMILION ENERGY INC (the Registrant)

Date: February 27, 2019

By: */s/ ("Lars Glemser")*
Lars Glemser
Vice President and Chief Financial Officer

EXHIBIT INDEX

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

Exhibits	Description
99.1	Annual Information Form for the Year Ended December 31, 2018
99.2	Management's Discussion and Analysis from the 2018 Annual Report to Shareholders
99.3	Audited Annual Financial Statements for the Year Ended December 31, 2018
99.4	Consent of Independent Registered Public Accounting Firm
99.5	Consent of Independent Petroleum Consultants
99.6	Officers' Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
99.7	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(b) or Rule 15d-14(b) of the Securities Exchange Act of 1934 and Section 1350 of Chapter 63 of Title 18 of the United States Code
101	Interactive data files

EXHIBIT 99.1

2018 ANNUAL INFORMATION FORM

For the year ended December 31, 2018

Dated February 27, 2019

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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]

Proved Developed Producing [3] [5] [6]	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	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**

Proved Developed Producing [3] [5] [6]	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	—	—	—	—	—	—	—	—	—	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**

Proved Developed Non-Producing [3] [5] [7]	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	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**

Proved Developed Non-Producing [3] [5] [7]	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	—	—	—	—	—	—	—	—	—	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) 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	—	—	—	—	—	—	—	—	—	—	—	—
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) 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	—	—	—	—	—	—	—	—	—	—	—	—
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) 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	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) 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	—	—	—	—	—	—	—	—	—	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)			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	4,812	4,812	4,812	—	—	—	—	—	—	—	—	–
Canada	46,426	46,379	40,751	83	83	71	—	—	—	212,151	212,020	193,16
France	20,355	20,355	18,389	—	—	—	—	—	—	580	580	54
Germany	3,841	3,841	3,740	—	—	—	—	—	—	53,415	53,415	45,83
Hungary	—	—	—	—	—	—	—	—	—	356	356	28
Ireland	—	—	—	—	—	—	—	—	—	44,890	44,890	44,89
Netherlands	—	—	—	—	—	—	—	—	—	61,527	61,527	58,28
United States	20,223	20,223	16,829	—	—	—	—	—	—	39,681	39,681	33,13
Total Probable	**95,657**	**95,610**	**84,521**	**83**	**83**	**71**	**—**	**—**	**—**	**412,600**	**412,469**	**376,14**

Probable [4]	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	—	—	—	—	—	—	—	—	—	4,812	4,812	4,81
Canada	213	213	202	2,856	2,856	2,657	20,518	20,502	17,381	102,897	102,812	90,87
France	—	—	—	—	—	—	—	—	—	20,452	20,452	18,48
Germany	—	—	—	—	—	—	—	—	—	12,744	12,744	11,38
Hungary	—	—	—	—	—	—	—	—	—	59	59	4
Ireland	—	—	—	—	—	—	—	—	—	7,482	7,482	7,48
Netherlands	—	—	—	—	—	—	140	140	134	10,395	10,395	9,84
United States	—	—	—	—	—	—	4,231	4,231	3,532	31,068	31,068	25,88
Total Probable	**213**	**213**	**202**	**2,856**	**2,856**	**2,657**	**24,889**	**24,873**	**21,047**	**189,909**	**189,824**	**168,80**

Proved Plus Probable [3] [4]	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	14,480	14,480	14,480	—	—	—	—	—	—	—	—	–
Canada	141,149	140,944	124,474	183	183	157	—	—	—	530,901	530,361	485,97
France	62,734	62,734	56,776	—	—	—	—	—	—	7,101	7,101	6,50
Germany	9,579	9,579	9,327	—	—	—	—	—	—	96,934	96,934	82,89
Hungary	—	—	—	—	—	—	—	—	—	1,144	1,144	91
Ireland	—	—	—	—	—	—	—	—	—	123,450	123,450	123,45
Netherlands	—	—	—	—	—	—	—	—	—	131,233	131,233	127,52
United States	33,212	33,212	27,582	—	—	—	—	—	—	84,386	84,386	70,33
Total Proved Plus Probable	**261,154**	**260,949**	**232,639**	**183**	**183**	**157**	**—**	**—**	**—**	**975,149**	**974,609**	**897,59**

Proved Plus Probable [3] [4]	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	—	—	—	—	—	—	—	—	—	14,480	14,480	14,48
Canada	1,119	1,119	1,062	4,684	4,684	4,309	54,053	53,988	45,832	284,836	284,476	252,35
France	—	—	—	—	—	—	—	—	—	63,918	63,918	57,86
Germany	—	—	—	—	—	—	—	—	—	25,735	25,735	23,14
Hungary	—	—	—	—	—	—	—	—	—	191	191	15
Ireland	—	—	—	—	—	—	—	—	—	20,575	20,575	20,57
Netherlands	—	—	—	—	—	—	324	324	317	22,196	22,196	21,57
United States	—	—	—	—	—	—	8,938	8,938	7,448	56,214	56,214	46,75
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**	**436,88**

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]

(M$)	Before Deducting Future Income Taxes Discounted At					After Deducting Future Income Taxes Discounted At				
	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**

(M$)	Before Deducting Future Income Taxes Discounted At 0%	5%	10%	15%	20%	After Deducting Future Income Taxes Discounted At 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) 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	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) 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	—	—	—	—	—	—	—	—	—	—	—	—
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) Factors	Proved (Mbbl)	Probable (Mbbl)	P+P (Mbbl)	Proved (Mboe)	Probable (Mboe)	P+P (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 Proved Probable P+P (1) (2) Factors	Total Oil (4) Proved (Mbbl)	Total Oil Probable (Mbbl)	Total Oil P+P (Mbbl)	Light & Medium Crude Oil Proved (Mbbl)	Light & Medium Crude Oil Probable (Mbbl)	Light & Medium Crude Oil P+P (Mbbl)	Heavy Oil Proved (Mbbl)	Heavy Oil Probable (Mbbl)	Heavy Oil P+P (Mbbl)	Tight Oil Proved (Mbbl)	Tight Oil Probable (Mbbl)	Tight Oil 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 Proved Probable P+P (1) (2) Factors	Total Gas (4) Proved (MMcf)	Total Gas Probable (MMcf)	Total Gas P+P (MMcf)	Conventional Natural Gas Proved (MMcf)	Conventional Natural Gas Probable (MMcf)	Conventional Natural Gas P+P (MMcf)	Coal Bed Methane Proved (MMcf)	Coal Bed Methane Probable (MMcf)	Coal Bed Methane P+P (MMcf)	Shale Gas Proved (MMcf)	Shale Gas Probable (MMcf)	Shale Gas 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 Proved Probable P+P (1) (2) Factors	Natural Gas Liquids Proved (Mbbl)	Natural Gas Liquids Probable (Mbbl)	Natural Gas Liquids P+P (Mbbl)	BOE Proved (Mboe)	BOE Probable (Mboe)	BOE 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 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	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 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	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 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	—	—	—	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 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	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Ireland 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	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 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	—	—	—	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 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	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 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	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 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	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 (
Canada								
Alberta	489	353	167	103	554	397	362	24
Saskatchewan	4,783	2,994	1,758	1,149	—	—	20	2
Total Canada	5,272	3,346	1,925	1,253	554	397	382	26
Australia (1)	17	17	1	1	—	—	—	–
France	344	337	89	88	1	1	2	
Germany	133	105	40	34	21	8	4	
Hungary	—	—	—	—	1	1	—	–
Ireland (1)	—	—	—	—	6	1	—	–
Netherlands	—	—	—	—	114	103	49	4
United States (Wyoming)	127	118	56	53	—	—	—	–
Total Vermilion	**5,893**	**3,923**	**2,111**	**1,429**	**697**	**512**	**437**	**31**

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	Vice President	Since October 2017, Vice President, Business Development of Vermilion

Calgary, Alberta Canada	Business Development	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)

	Before Income Taxes, Discounted at (5)					After Income Taxes, Discounted at (5)				
(M$)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Contingent (1C) - Low Estimate (6)										
Development Pending (10)										
Australia	—	—	—	—	—	—	—	—	—	—
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 CO_2 pilot project still being in the conceptual study stage, GLJ has estimated risked unclarified best estimate contingent resources at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM. The expected timeline is 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	
Prospect (10)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)	Chance of Commerciality % (9)	Gross (Mboe)	Net (Mboe)
Prospective (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	Effective Date of	Location of Reserves (Country or Foreign	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$)			
Evaluator	Evaluation Report	Geographic Area)	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

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves (Country or Foreign Geographic Area)	Risked Volume (Mboe)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$)		
					Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants	December 31, 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.

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

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

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

III. DUTIES AND RESPONSIBILITIES

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

A. Financial Statements and Other Financial Information

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

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

Review, and where appropriate, discuss:

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

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

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

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

D. Compliance

The Committee shall:

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

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

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

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

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

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

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

E. Other

The Committee shall:

i) establish and periodically review procedures for:

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

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

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

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

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

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

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

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

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

IV. ACCOUNTABILITY

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

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

Disclaimer

Certain statements included or incorporated by reference in this document may constitute forward looking statements or financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this document may include, but are not limited to: capital expenditures and Vermilion's ability to fund such expenditures; Vermilion's additional debt capacity providing it with additional working capital; the flexibility of Vermilion's capital program and operations; business strategies and objectives; operational and financial performance; estimated volumes of reserves and resources; petroleum and natural gas sales; future production levels and the timing thereof, including Vermilion's 2019 guidance, and rates of average annual production growth; the effect of changes in crude oil and natural gas prices, changes in exchange rates and significant declines in production or sales volumes due to unforeseen circumstances; the effect of possible changes in critical accounting estimates; statements regarding the growth and size of Vermilion's future project inventory, and the wells expected to be drilled in 2019; exploration and development plans and the timing thereof; Vermilion's ability to reduce its debt, including its ability to redeem senior unsecured notes prior to maturity; statements regarding Vermilion's hedging program, its plans to add to its hedging positions, and the anticipated impact of Vermilion's hedging program on project economics and free cash flows; the potential financial impact of climate-related risks; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates and Vermilion's expectations regarding future taxes and taxability; and the timing of regulatory proceedings and approvals.

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

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

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

All crude oil and natural gas reserve and resource information contained in this document has been prepared and presented in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook. Reserves estimates have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for such development. The actual crude oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document.

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

Financial data contained within this document are reported in Canadian dollars, unless otherwise stated.

Abbreviations

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO ‘C’ hub in Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
tCO2e	tonnes of carbon dioxide equivalent
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Management's Discussion and Analysis

The following is Management's Discussion and Analysis ("MD&A"), dated February 27, 2019, of Vermilion Energy Inc.'s ("Vermilion", "we", "our", "us" or the "Company") operating and financial results as at and for the three months and year ended December 31, 2018 compared with the corresponding periods in the prior year.

This discussion should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2018 and 2017, together with the accompanying notes. Additional information relating to Vermilion, including its Annual Information Form, is available on SEDAR at www.sedar.com or on Vermilion's website at www.vermilionenergy.com.

The audited consolidated financial statements for the year ended December 31, 2018 and comparative information have been prepared in Canadian dollars and in accordance with International Financial Reporting Standards ("IFRS" or, alternatively, "GAAP") as issued by the International Accounting Standards Board ("IASB").

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

- Fund flows from operations: Fund flows from operations is a measure of profit or loss in accordance with IFRS 8 "Operating Segments". Please see "Segmented Information" in the "Notes to the Consolidated Financial Statements" for a reconciliation of fund flows from operations to net earnings. We analyze fund flows from operations both on a consolidated basis and on a business unit basis in order to assess the contribution of each business unit to our ability to generate income necessary to pay dividends, repay debt, fund asset retirement obligations and make capital investments.
- Net debt: Net debt is a capital management measure in accordance with IAS 1 "Presentation of Financial Statements". Net debt is comprised of long-term debt plus current liabilities less current assets and represents Vermilion's net financing obligations after adjusting for the timing of working capital fluctuations. Net debt excludes lease obligations which are secured by a corresponding right-of-use asset. Please see "Capital disclosures" in the "Notes to the Consolidated Financial Statements" for additional information.
- Netbacks: Netbacks are per boe and per mcf performance measures used in the analysis of operational activities. We assess netbacks both on a consolidated basis and on a business unit basis in order to compare and assess the operational and financial performance of each business unit versus other business units and also versus third party crude oil and natural gas producers.

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

Condensate Presentation

We report our condensate production in Canada and the Netherlands business units within the crude oil and condensate production line. We believe that this presentation better reflects the historical and forecasted pricing for condensate, which is more closely correlated with crude oil pricing than with pricing for propane, butane and ethane (collectively "NGLs" for the purposes of this report).

Guidance

On October 30, 2017, we released our 2018 capital expenditure guidance of $315 million and associated production guidance of between 74,500 to 76,500 boe/d. On January 15, 2018, we increased our capital expenditure guidance to $325 million and production guidance to between 75,000 to 77,500 boe/d to reflect the post-closing impact of the acquisition of a private southeast Saskatchewan and southwest Manitoba light oil producer. On April 16, 2018, we increased our capital expenditure guidance to $430 million and production guidance to between 86,000 to 90,000 boe/d to reflect the post-closing impact of the acquisition of Spartan Energy Corp. On July 30, 2018, we increased our capital expenditure guidance to $500 million to reflect the acceleration of our Australia drilling campaign into Q4 2018, and to a lesser extent to account for the impact of foreign exchange fluctuations on our Canadian dollar capital levels. On October 25, 2018, we increased our capital expenditure guidance to $510 million to reflect additional capital activity associated with the assets acquired in the Powder River Basin in August of 2018. Actual 2018 capital spending of $518 million was within 2% of our guidance and 2018 average production of 87,270 boe/d was within 1% of the mid-point of our guidance range.

On October 25, 2018, we released our 2019 capital budget and related guidance. The 2019 total budget and production guidance remain unchanged, although we have deferred some activity to later in the year and reallocated capital between business units, the breakdown of which can be found in our corporate presentation located on our website.

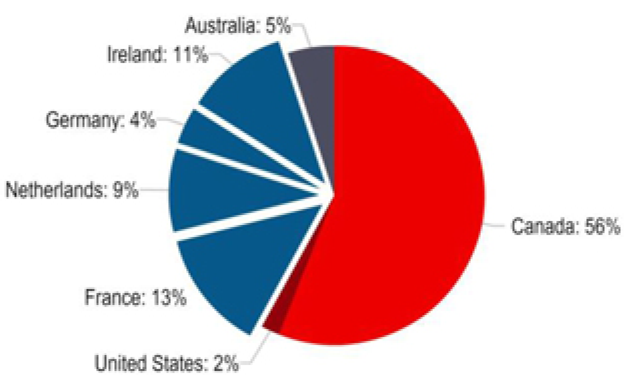
The following table summarizes our guidance:

	Date	Capital Expenditures ($MM)	Production (boe/d)
2018 Guidance			
2018 Guidance	October 30, 2017	315	74,500 to 76,500
2018 Guidance	January 15, 2018	325	75,000 to 77,500
2018 Guidance	April 16, 2018	430	86,000 to 90,000
2018 Guidance	July 30, 2018	500	86,000 to 90,000
2018 Guidance	October 25, 2018	510	86,000 to 90,000
2018 Actual Results		518	87,270
2019 Guidance			
2019 Guidance	October 25, 2018	530	101,000 to 106,000

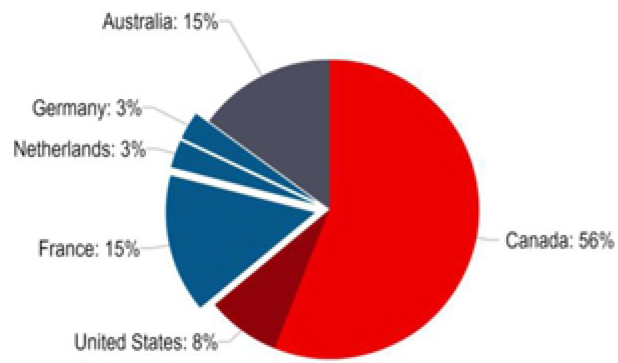
Vermilion's Business

Vermilion is a Calgary, Alberta based international oil and gas producer focused on the acquisition, exploration, development, and optimization of producing properties in North America, Europe, and Australia. We manage our business through our Calgary head office and our international business unit offices. This MD&A separately discusses each of our business units in addition to our corporate segment.

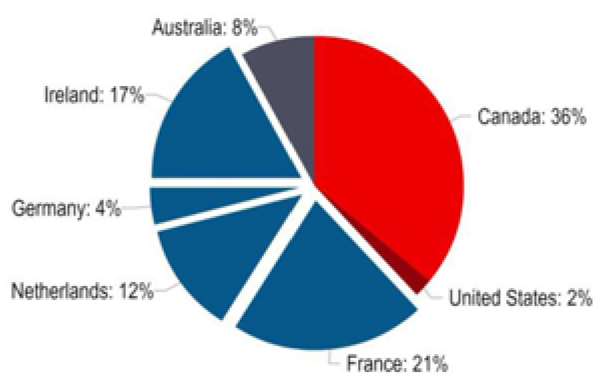
2018 production of 87,270 boe/d by business unit



2018 capital expenditures of $518MM by business unit



2018 fund flows from operations of $839MM by business unit

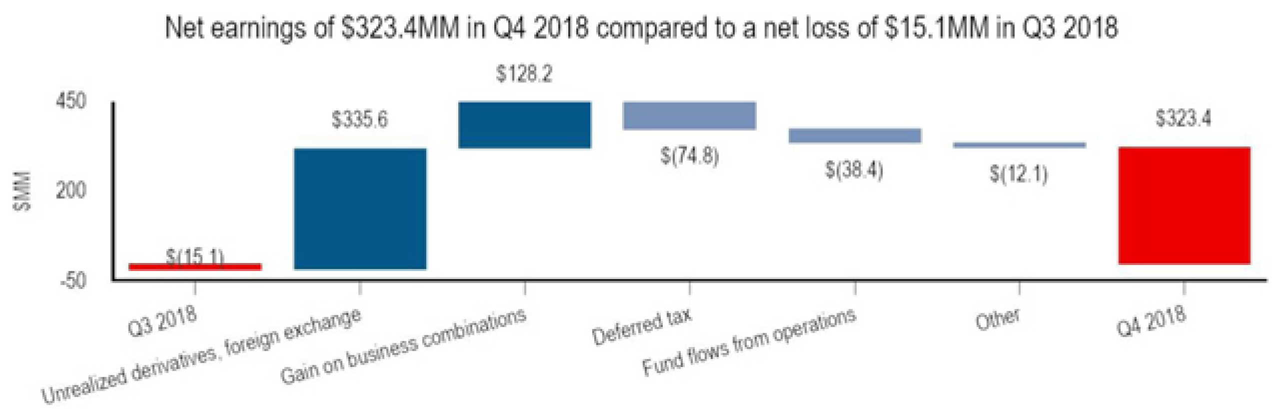


Consolidated Results Overview

	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Production								
Crude oil and condensate (bbls/d)	**47,678**	47,152	27,830	1%	71%	**39,182**	27,721	41%
NGLs (bbls/d)	**7,815**	6,839	5,279	14%	48%	**6,366**	4,194	52%
Natural gas (mmcf/d)	**276.77**	253.38	238.27	9%	16%	**250.33**	216.64	16%
Total (boe/d)	**101,621**	96,222	72,821	6%	40%	**87,270**	68,021	28%
Sales								
Crude oil and condensate (bbls/d)	**47,620**	46,368	27,638	3%	72%	**38,741**	27,483	41%
NGLs (bbls/d)	**7,815**	6,839	5,279	14%	48%	**6,366**	4,194	52%
Natural gas (mmcf/d)	**276.77**	253.38	238.27	9%	16%	**250.33**	216.64	16%
Total (boe/d)	**101,563**	95,437	72,628	6%	40%	**86,829**	67,784	28%
Build in inventory (mbbls)	**5**	73	18			**160**	87	
Financial metrics								
Fund flows from operations ($M)	**222,342**	260,705	181,253	(15)%	23%	**838,652**	602,565	39%
Per share ($/basic share)	**1.46**	1.71	1.49	(15)%	(2)%	**5.96**	5.00	19%
Net earnings	**323,373**	(15,099)	8,645	N/A	3,641%	**271,650**	62,258	336%
Per share ($/basic share)	**2.12**	(0.10)	0.07	N/A	2,929%	**1.93**	0.52	271%
Net debt ($M)	**1,929,529**	2,034,086	1,371,790	(5)%	41%	**1,929,529**	1,371,790	41%
Cash dividends ($/share)	**0.690**	0.690	0.645	—%	7%	**2.715**	2.580	5%
Activity								
Capital expenditures ($M)	**163,580**	146,185	74,303	12%	120%	**518,214**	320,449	62%
Acquisitions ($M)	**2,689**	198,173	3,048			**1,759,425**	27,637	
Gross wells drilled	**73.00**	65.00	8.00			**185.00**	56.00	
Net wells drilled	**45.08**	58.97	6.00			**147.93**	46.58	

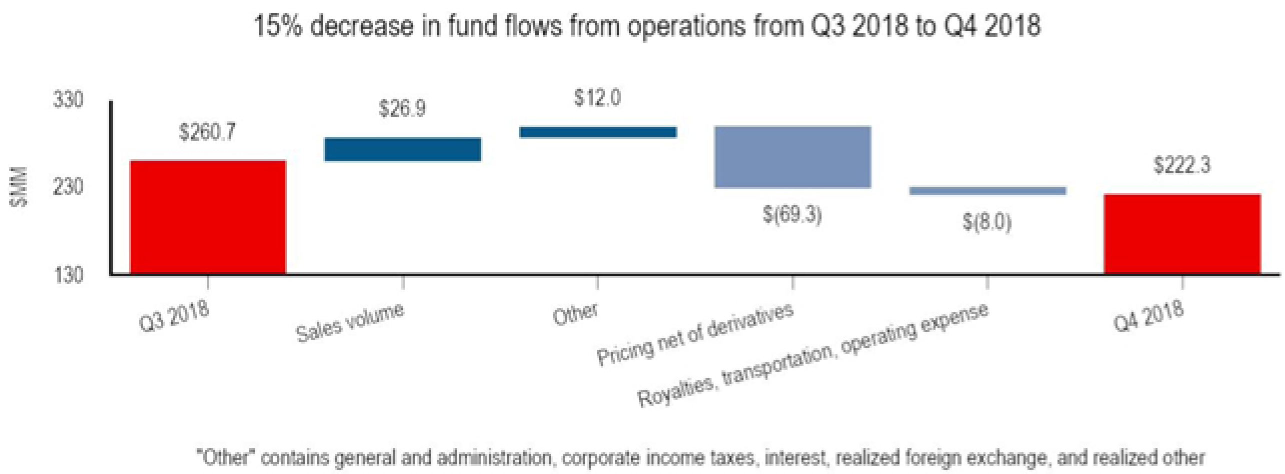
Financial performance review

Q4 2018 vs. Q3 2018



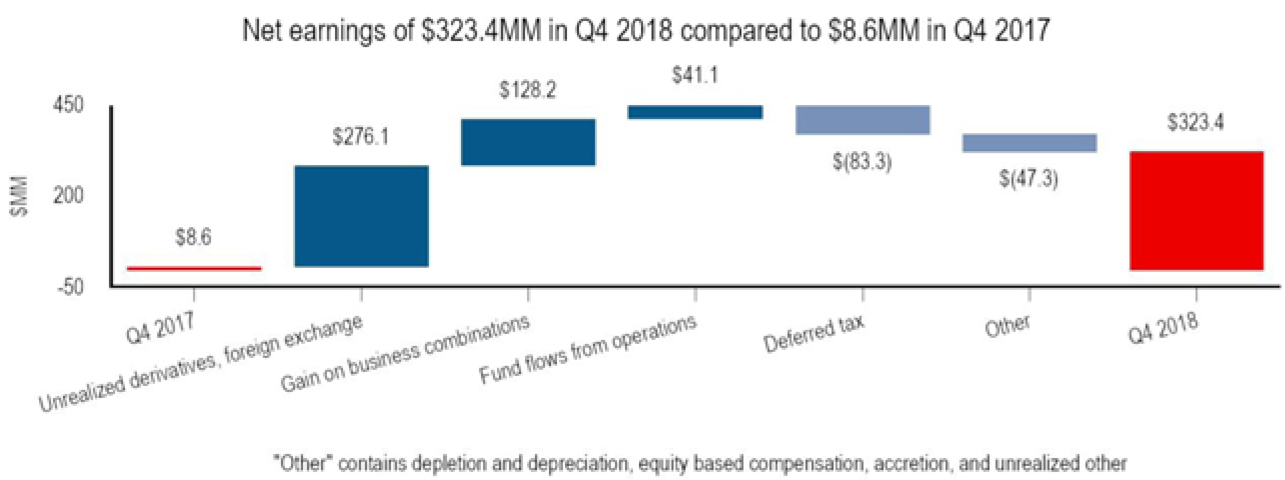
"Other" contains depletion and depreciation, equity based compensation, accretion, and unrealized other

- We recorded net earnings for Q4 2018 of $323.4 million ($2.12/basic share) compared to a net loss of $15.1 million ($0.10/basic share) in Q3 2018. This net earnings growth was primarily attributable to a $348.9 million increase in unrealized gains on derivative instruments and a $128.2 million gain recorded on business combinations. These increases were partially offset by a $38.4 million decrease in fund flows from operations.

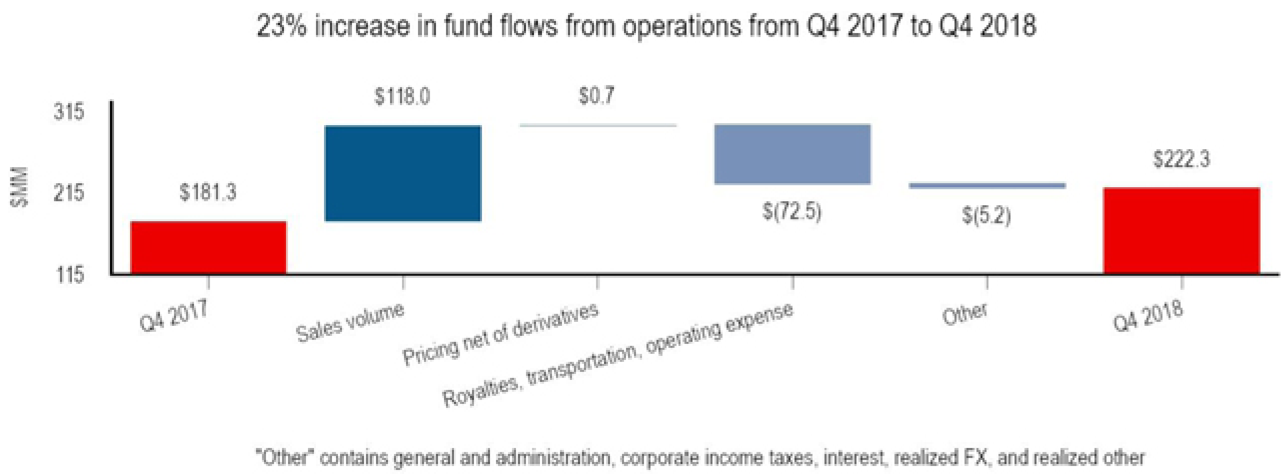


- We generated fund flows from operations of $222.3 million during Q4 2018, a decrease of 15% from Q3 2018. This quarter-over-quarter decrease was primarily due to weaker crude oil prices during the current period, including a 48% decrease in in the Edmonton sweet index. The diversified nature of our production somewhat mitigated this 48% decrease in the Edmonton sweet index as illustrated by an attenuated 23% decrease in our crude oil and condensate realized price and a 16% decrease in our consolidated realized price.

Q4 2018 vs. Q4 2017

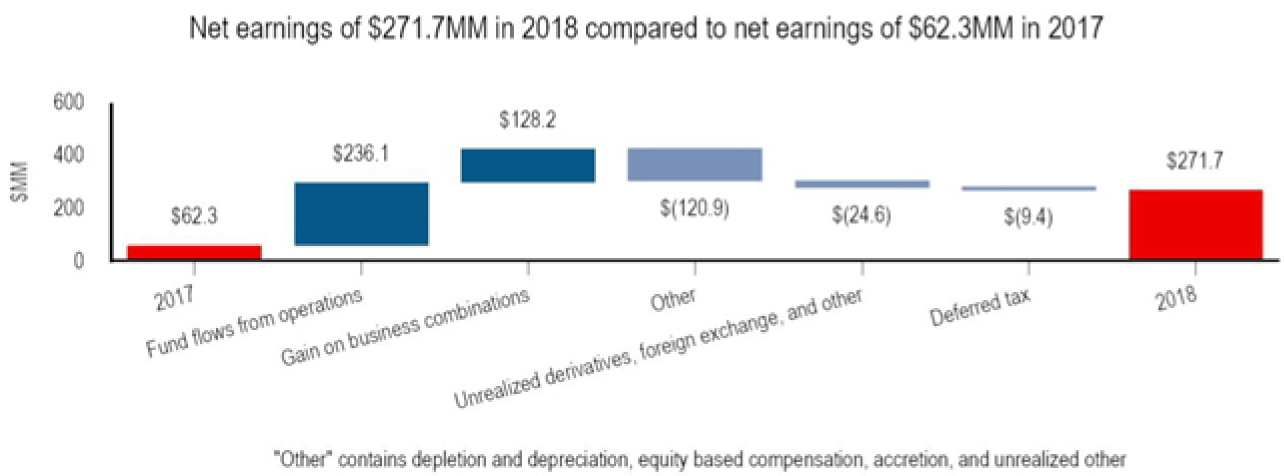


- We recorded net earnings for Q4 2018 of $323.4 million ($2.12/basic share) compared to net earnings of $8.6 million ($0.07/basic share) in Q4 2017. The net earnings growth was the result of a 23% increase in fund flows from operations driven by increased sales volumes in Q4 2018 as compared to Q4 2017, an increase in unrealized gain on derivative instruments ($193.1 million), and a $128.2 million gain on business combinations.

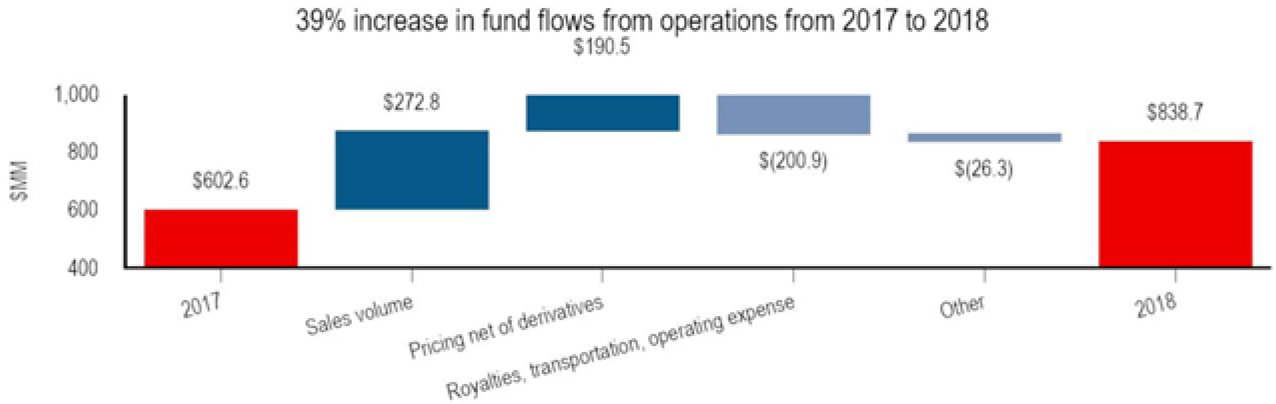


- Fund flows from operations increased 23% in Q4 2018 versus Q4 2017. This increase occurred due to higher sales volumes in Q4 2018 partially offset by increased royalties, transportation, and operating expense associated with these higher volumes.

2018 vs. 2017



- For the year ended December 31, 2018, net earnings of $271.7 million compared to net earnings of $62.3 million in 2017. The increase in net earnings primarily resulted from a year-over-year increase in fund flows from operations of $236.1 million and a gain on business combinations of $128.2 million. These increases were partially offset by increased depletion and depreciation expense resulting from higher production volumes.



"Other" contains general and administration, current income taxes, interest, realized foreign exchange, and realized other

- Fund flows from operations increased 39% for the year ended December 31, 2018 versus 2017 due to increased sales volumes and higher realized pricing offset by an increase in royalties, transportation and operating expense. Our consolidated realized price increased by 19% from $44.41/boe to $52.95/boe due to an increase in our relative crude oil production and stronger crude oil and European gas pricing. Our sales volumes increased by 28% due to production increases in Canada, the Netherlands, and the United States.
- On a per unit basis, fund flows from operations increased by 9% from $24.34/boe for the year ended December 31, 2017 to $26.47/boe in 2018. This increase reflects the improvement in our realized price per boe and includes a 25% decrease in per boe general and administration expenses as our overall expense decreased by 4% despite production growth. These decreases were partially offset by higher per unit costs for royalties (resulting from the stronger commodity price environment and higher royalty rates) and operating expenses. Per boe operating expenses increased by $1.47/boe from $9.79/boe in 2017 to $11.26/boe in 2018 due in part to a stronger Euro relative to the Canadian dollar in 2018 and increased expenses associated with higher value crude oil production in Canada.

Production review

Q4 2018 vs. Q3 2018

- Consolidated average production of 101,621 boe/d during Q4 2018 increased 6% versus Q3 2018. The increase in production was primarily attributable to new wells brought on production in Canada, growth in the United States through an acquisition closed in Q3 2018, and a full quarter of production from wells brought on production in Q3 2018 in the Netherlands and Hungary. These production increases were partially offset by an 11% decrease in Australia resulting from a planned shutdown of the Wandoo field for maintenance and downtime associated with drilling.

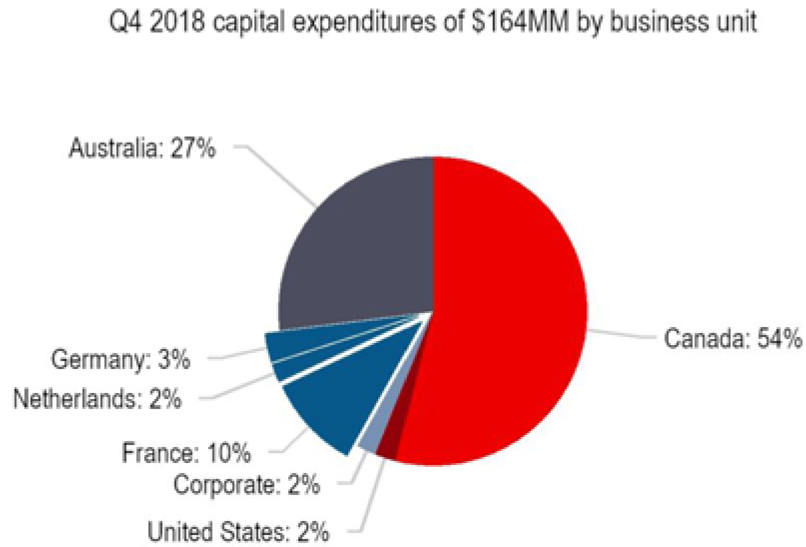
Q4 2018 vs. Q4 2017

- Consolidated average production of 101,621 boe/d in Q4 2018 represented an increase of 40% from Q4 2017 due to growth in Canada and the United States. In Canada, year-over-year growth was the result of both acquisitions and continued development of our Mannville condensate-rich resource play and southeast Saskatchewan light oil development. In the United States, production growth resulted from an acquisition in Q3 2018 and organic drilling activity.

2018 vs. 2017

- For the year ended December 31, 2018, consolidated average production of 87,270 boe/d represented an increase of 28% from 2017 due to production growth in Canada, the United States, and the Netherlands. In Canada, production increased by 19,120 boe/d due to contributions from acquisitions and continued development of our Mannville condensate-rich resource play and southeast Saskatchewan light oil development. In the United States, production growth resulted from an acquisition in Q3 2018 and organic drilling activity. In the Netherlands, year-over-year production growth occurred following the receipt of production permits (the absence of which restricted production from certain wells in the comparable period in 2017).

Activity review



- For the three months ended December 31, 2018, capital expenditures of $163.6 million primarily related to activity in Canada and Australia. In Canada, capital expenditures of $90.2 million included the drilling of 72.0 (44.1 net) wells, primarily in southeast Saskatchewan. In Australia, capital expenditures of $43.8 million related to the two (2.0 net) well drilling program.

Sustainability review

Dividends

- Declared dividends of $0.23 per common share per month for Q4 2018, resulting in total dividends declared of $2.715 per common share for the year ended December 31, 2018.
- In Q2 2018, we increased our monthly dividend by 7% resulting in a year-over-year increase in cash dividends. The Q2 2018 increase was our fourth dividend increase (previously Vermilion's distribution in the income trust era) since we began paying a distribution in 2003.

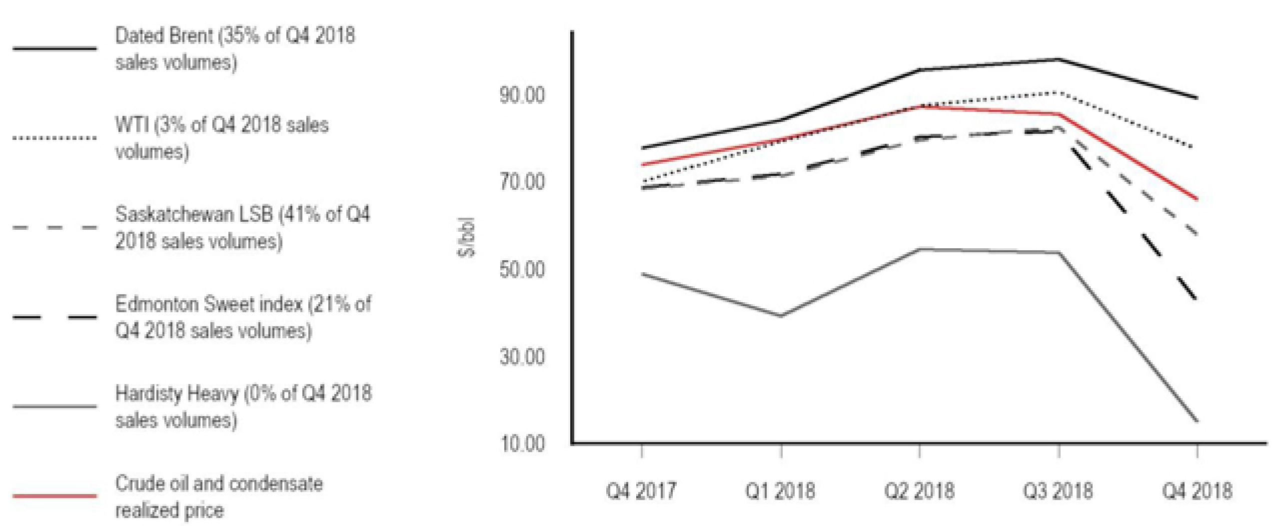
Long-term debt and net debt

- Long-term debt increased from $1.3 billion as at December 31, 2017 to $1.8 billion as at December 31, 2018. This increase was primarily a result of increased borrowings on the revolving credit facility to fund acquisitions in 2018. These increases were coupled with the impact of the stronger US dollar on our US denominated Sr. Unsecured Notes.
- Net debt increased to $1.9 billion as at December 31, 2018 from $1.4 billion at December 31, 2017, primarily due to acquisition activity in 2018, partially offset by a $115.6 million decrease in net current derivative liability at December 31, 2018 (from a net liability position of $60.9 million as at December 31, 2017 to a net asset position of $54.7 million).
- The ratio of net debt to fund flows from operations remained consistent at 2.30 (2017 - 2.28) as the increase in net debt was offset by a partial year of contribution from the acquisitions that closed in 2018.

Commodity Prices

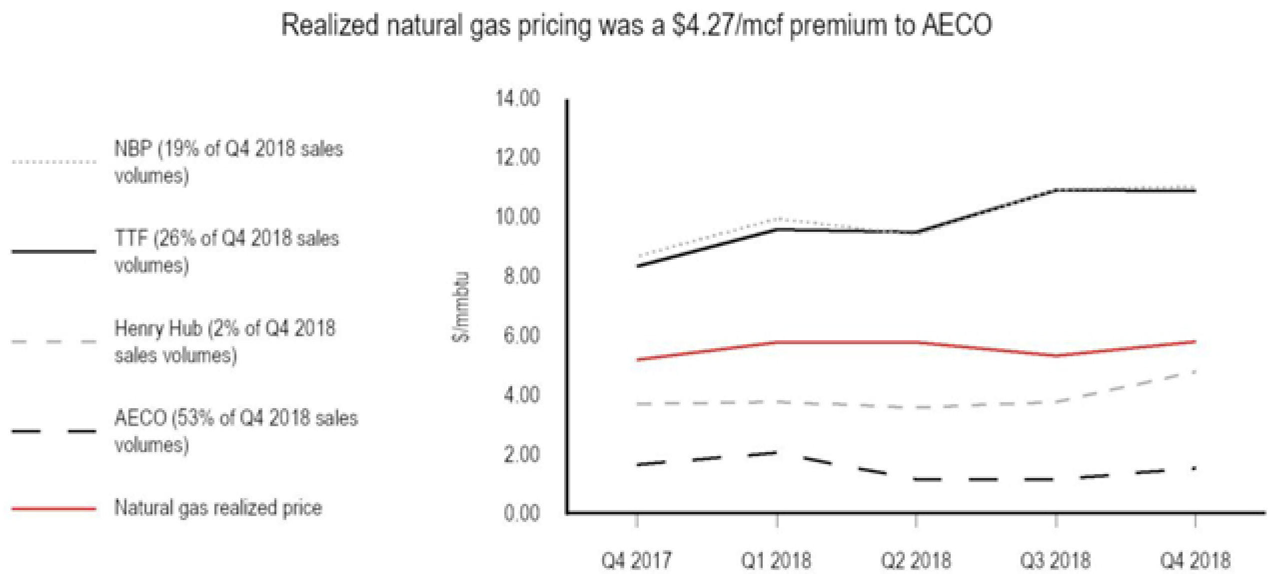
	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Crude oil								
WTI ($/bbl)	**77.71**	90.83	70.43	(14)%	10%	**83.94**	66.13	27%
WTI (US $/bbl)	**58.81**	69.50	55.40	(15)%	6%	**64.77**	50.95	27%
Edmonton Sweet index ($/bbl)	**42.96**	81.92	68.98	(48)%	(38)%	**69.53**	62.94	10%
Edmonton Sweet index (US $/bbl)	**32.51**	62.68	54.26	(48)%	(40)%	**53.65**	48.49	11%
Saskatchewan LSB index ($/bbl)	**58.18**	82.79	68.70	(30)%	(15)%	**73.17**	62.10	18%
Saskatchewan LSB index (US $/bbl)	**44.03**	63.35	54.04	(30)%	(19)%	**56.46**	47.85	18%
Dated Brent ($/bbl)	**89.54**	98.37	78.05	(9)%	15%	**92.07**	70.44	31%
Dated Brent (US $/bbl)	**67.76**	75.27	61.39	(10)%	10%	**71.04**	54.27	31%
Hardisty Heavy ($/bbl)	**15.28**	54.11	49.19	(72)%	(69)%	**41.07**	45.67	(10)%
Hardisty Heavy (US $/bbl)	**11.56**	41.40	38.69	(72)%	(70)%	**31.69**	35.19	(10)%
Natural gas								
AECO ($/mcf)	**1.56**	1.19	1.69	31%	(8)%	**1.50**	2.16	(31)%
NBP ($/mcf)	**11.03**	10.95	8.70	1%	27%	**10.35**	7.49	38%
NBP (€/mcf)	**7.31**	7.20	5.81	2%	26%	**6.76**	5.12	32%
TTF ($/mcf)	**10.91**	10.92	8.36	—%	31%	**10.23**	7.43	38%
TTF (€/mcf)	**7.23**	7.18	5.58	1%	30%	**6.69**	5.07	32%
Henry Hub ($/mcf)	**4.82**	3.80	3.73	27%	29%	**4.01**	4.04	(1)%
Henry Hub (US $/mcf)	**3.65**	2.90	2.93	26%	25%	**3.09**	3.11	(1)%
Average exchange rates								
CDN $/US $	**1.32**	1.31	1.27	1%	4%	**1.30**	1.30	—%
CDN $/Euro	**1.51**	1.52	1.50	(1)%	1%	**1.53**	1.46	5%
Realized Prices								
Crude oil and condensate ($/bbl)	**66.19**	85.84	74.12	(23)%	(11)%	**79.16**	67.00	18%
NGLs ($/bbl)	**25.69**	27.97	29.28	(8)%	(12)%	**26.33**	25.00	5%
Natural gas ($/mcf)	**5.83**	5.35	5.23	9%	11%	**5.45**	4.91	11%
Total ($/boe)	**48.90**	57.90	47.49	(16)%	3%	**52.95**	44.41	19%

Realized crude oil and condensate price was a 54% premium to the Edmonton Sweet Index

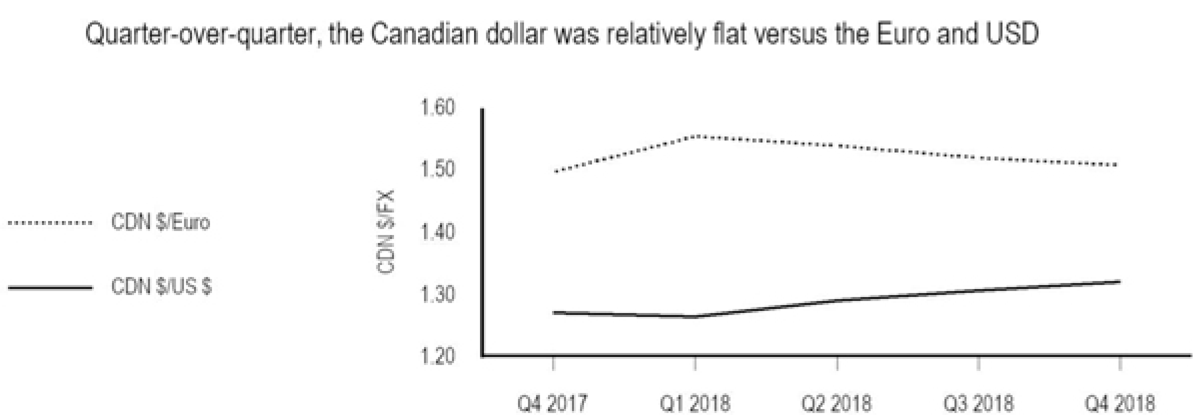


- Crude oil prices decreased throughout Q4 2018, driven by record global production levels and macroeconomic concerns. Quarter-over-quarter, WTI and Brent decreased by 14% and 9%, respectively, in Canadian dollar terms. Despite the end-of-year weakness in 2018, for the three months and year ended December 31, 2018, WTI increased 10% and 27%, respectively, in Canadian dollar terms versus the comparable periods in the prior year. Similarly, Brent increased 15% and 31%, respectively, in Canadian dollar terms for the three months and year ended December 31, 2018 versus the comparable periods in 2017.

- Western Canadian takeaway capacity constraints negatively impacted differentials in Q4 2018 versus Q3 2018; the Edmonton Sweet differential widened by $19.48/bbl, the Saskatchewan LSB differential widened by $14.78/bbl, and the Hardisty WCS differential widened by $19.15/bbl.
- Vermilion's crude oil production benefits from light oil pricing and no exposure to significantly discounted heavy crude oil. Approximately 35% of our Q4 2018 crude oil and condensate production was priced at the Dated Brent index (which averaged a premium to WTI of US$8.95/bbl) while the remainder of our crude oil and condensate production was priced at the Saskatchewan LSB, Edmonton Sweet, and WTI indices. As a result, our Q4 2018 crude oil and condensate realized price of $66.19/bbl represented a 54% premium to the Edmonton Sweet index and a 333% premium to Hardisty Heavy.



- European natural gas prices were relatively unchanged in Q4 2018 compared to Q3 2018. For the year ended December 31, 2018, TTF and NBP prices in Canadian dollar terms increased 38% compared to 2017. Competition from Asia for liquefied natural gas ("LNG") supply, strong demand from both the power sector and for storage injections, and surging carbon prices in the European Union, all played a role in 2018 price strength.
- Natural gas prices at AECO increased by 31% in Q4 2018 as compared to Q3 2018. While the AECO gas market continues to face egress challenges, the seasonal shift from a summer quarter to a winter quarter drove stronger domestic gas demand.
- For Q4 2018, average European natural gas prices represented a $9.41/mcf premium to AECO and a $6.15/mcf premium to Henry Hub pricing. Approximately 45% of our natural gas production in Q4 2018 benefited from this premium European pricing. As a result, our consolidated natural gas realized price was a $4.27/mcf premium to AECO and a $1.01/mcf premium to Henry Hub pricing.



- For the three months ended December 31, 2018, the Canadian dollar weakened by 1% against the US dollar quarter-over-quarter. The annual average in 2018 was nearly unchanged versus 2017.
- For the three months ended December 31, 2018, the Canadian dollar strengthened by 1% against the Euro quarter-over-quarter. The annual average in 2018 was 5% weaker versus 2017.

Canada Business Unit

Overview

Production and assets focused in West Pembina near Drayton Valley, Alberta and in southeast Saskatchewan and Manitoba.

- Potential for three significant resource plays sharing the same surface infrastructure in the West Pembina region in Alberta:
  - Mannville condensate-rich gas (2,400 - 2,700m depth) - in development phase
  - Cardium light oil (1,800m depth) - in development phase
  - Duvernay condensate-rich gas (3,200 - 3,400m depth) - no investment at present
- Southeast Saskatchewan light oil development:
  - Targeting the Mississippian Midale (1,400 - 1,700m depth), Frobisher/Alida (1,200 - 1,400m depth) and Ratcliffe (1,800 - 1,900m) formations

Operational and financial review

Canada business unit ($M except as indicated)	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Production and sales								
Crude oil and condensate (bbls/d)	**29,557**	28,477	9,703	4%	205%	**21,154**	9,051	134%
NGLs (bbls/d)	**6,816**	6,126	5,235	11%	30%	**5,914**	4,144	43%
Natural gas (mmcf/d)	**146.65**	136.77	107.91	7%	36%	**129.37**	97.89	32%
Total (boe/d)	**60,814**	57,397	32,923	6%	85%	**48,630**	29,510	65%
Production mix (% of total)								
Crude oil and condensate	**49%**	50%	29%			**43%**	31%	
NGLs	**11%**	10%	16%			**13%**	14%	
Natural gas	**40%**	40%	55%			**44%**	55%	
Activity								
Capital expenditures	**90,211**	89,837	26,865	—%	236%	**277,857**	148,667	87%
Acquisitions	**12,233**	6,146	788			**1,573,964**	22,011	
Gross wells drilled	**72.00**	65.00	6.00			**173.00**	44.00	
Net wells drilled	**44.08**	58.97	4.00			**135.93**	35.56	
Financial results								
Sales	**186,308**	243,016	94,522	(23)%	97%	**671,172**	330,903	103%
Royalties	**(25,584)**	(33,801)	(9,301)	(24)%	175%	**(84,696)**	(33,258)	155%
Transportation	**(11,129)**	(9,057)	(4,836)	23%	130%	**(29,912)**	(17,368)	72%
Operating	**(62,064)**	(55,577)	(22,356)	12%	178%	**(177,499)**	(80,444)	121%
General and administration	**(2,150)**	(1,316)	(2,540)	63%	(15)%	**(6,057)**	(9,604)	(37)%
Fund flows from operations	**85,381**	143,265	55,489	(40)%	54%	**373,008**	190,229	96%
Netbacks ($/boe)								
Sales	**33.30**	46.02	31.21	(28)%	7%	**37.81**	30.72	23%
Royalties	**(4.57)**	(6.40)	(3.07)	(29)%	49%	**(4.77)**	(3.09)	54%
Transportation	**(1.99)**	(1.72)	(1.60)	16%	24%	**(1.69)**	(1.61)	5%
Operating	**(11.09)**	(10.52)	(7.38)	5%	50%	**(10.00)**	(7.47)	34%
General and administration	**(0.38)**	(0.25)	(0.84)	52%	(55)%	**(0.34)**	(0.89)	(62)%
Fund flows from operations netback	**15.27**	27.13	18.32	(44)%	(17)%	**21.01**	17.66	19%
Realized prices								
Crude oil and condensate ($/bbl)	**54.04**	79.86	69.20	(32)%	(22)%	**70.16**	63.41	11%
NGLs ($/bbl)	**25.53**	27.82	29.18	(8)%	(13)%	**26.20**	25.00	5%
Natural gas ($/mcf)	**1.73**	1.44	1.88	20%	(8)%	**1.54**	2.34	(34)%
Total ($/boe)	**33.30**	46.02	31.21	(28)%	7%	**37.81**	30.72	23%
Reference prices								
WTI (US $/bbl)	**58.81**	69.50	55.40	(15)%	6%	**64.77**	50.95	27%
Edmonton Sweet index ($/bbl)	**42.96**	81.92	68.98	(48)%	(38)%	**69.53**	62.94	10%

Saskatchewan LSB index ($/bbl)	**58.18**	82.79	68.70	(30)%	(15)%	**73.17**	62.10	18%
AECO ($/mcf)	**1.56**	1.19	1.69	31%	(8)%	**1.50**	2.16	(31)%

Production

- Q4 2018 production increased 6% from the prior quarter due to strong operating performance and new well completions from our Saskatchewan and Alberta assets. Quarterly production increased 82% year-over-year primarily due to our acquisition of Spartan Energy Corp. in May 2018.
- Production in Alberta averaged approximately 34,000 boe/d in Q4 2018, an increase of 4% quarter-over-quarter.
- Production in Saskatchewan averaged approximately 26,800 boe/d in Q4 2018, an increase of 9% quarter-over-quarter.

Activity review

- Vermilion drilled 43 (41.1 net) operated wells and participated in the drilling of 29 (2.9 net) non-operated wells in Canada during Q4 2018.

  Alberta
  - In Q4 2018, we drilled or participated in nine (8.9 net) operated and two (0.4 net) non-operated wells, completed four (3.9 net) operated and three (0.8 net) non-operated wells, and brought on production four (4.0 net) operated and four (1.1 net) non-operated wells in Alberta.
  - In 2018, we drilled or participated in 27 (23.4 net) wells in Alberta, which included the drilling of 23 (20.7 net) Mannville wells.

  Saskatchewan
  - In Q4 2018, we drilled or participated in 34 (32.3 net) operated wells and 27 (2.5 net) non-operated wells, completed 40 (37.3 net) operated and 26 (2.8 net) non-operated wells, and brought 51 (48.3 net) operated and 27 (3.2 net) non-operated wells on production.
  - In 2018, we drilled or participated in 146 (112.6 net) wells in Saskatchewan.

- On May 28, 2018, Vermilion acquired 100% of the issued and outstanding common shares of Spartan, a publicly traded southeast Saskatchewan oil and gas producer. 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.

Sales

- The realized price for our crude oil and condensate production in Canada is linked to WTI subject to market conditions in western Canada (as reflected by the Saskatchewan LSB index price in Saskatchewan and the Edmonton Sweet index price in Alberta). The realized price of our natural gas in Canada is based on the AECO index.
- Q4 2018 sales per boe decreased 28% compared to Q3 2018 consistent with the decrease in crude oil and condensate pricing. Quarter-over-quarter, our crude oil and condensate production mix remained stable at approximately 50% of production.
- For the year ended December 31, 2018, sales per boe increased versus 2017 due to increased Saskatchewan LSB and Edmonton Sweet index pricing coupled with an increased weighting towards higher-priced crude oil and condensate production.

Royalties

- Royalties as a percentage of sales for the three months and year ended December 31, 2018 of 13.7% and 12.6%, respectively, increased from the comparable periods in 2017 due to the impact of the Spartan assets, which have higher associated royalty rates.

Transportation

- Transportation expense for the three months and year ended December 31, 2018 increased on a per unit basis versus all comparable periods due to an increase in production that incurs higher transportation expense.

Operating

- Operating expense increased in Q4 2018 versus Q3 2018 on both a dollar and per unit basis. On a dollar basis, this increase was due to higher production volumes and the per unit increase was caused by a favourable adjustment recorded in the prior quarter.

- For the three months and year ended December 31, 2018, operating expense increased on both a dollar and per unit basis versus the comparable periods in 2017. On a dollar basis, the increase in operating expense was driven by higher production volumes during Q4 2018. On a per unit basis, the increase in operating expense was primarily attributable to the impact of production from the Spartan assets, which have higher associated per unit operating expense.

France Business Unit

Overview

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

Operational and financial review

France business unit ($M except as indicated)	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	**11,317**	11,407	11,215	(1)%	1%	**11,362**	11,084	3%
Natural gas (mmcf/d)	**0.82**	—	—	100%	100%	**0.21**	—	100%
Total (boe/d)	**11,454**	11,407	11,215	—%	2%	**11,396**	11,085	3%
Sales								
Crude oil (bbls/d)	**10,975**	11,482	11,397	(4)%	(4)%	**11,012**	10,950	1%
Natural gas (mmcf/d)	**0.82**	—	—	100%	100%	**0.21**	—	100%
Total (boe/d)	**11,111**	11,482	11,397	(3)%	(3)%	**11,047**	10,950	1%
Inventory (mbbls)								
Opening crude oil inventory	**293**	300	214			**197**	148	
Crude oil production	**1,041**	1,049	1,032			**4,147**	4,046	
Crude oil sales	**(1,009)**	(1,056)	(1,049)			**(4,019)**	(3,997)	
Closing crude oil inventory	**325**	293	197			**325**	197	
Activity								
Capital expenditures	**17,008**	15,779	20,027	8%	(15)%	**79,758**	73,381	9%
Gross wells drilled	**—**	—	2.00			**5.00**	7.00	
Net wells drilled	**—**	—	2.00			**5.00**	7.00	
Financial results								
Sales	**85,889**	100,840	78,778	(15)%	9%	**360,602**	268,103	35%
Royalties	**(11,976)**	(12,765)	(10,599)	(6)%	13%	**(46,781)**	(28,565)	64%
Transportation	**(3,242)**	(2,013)	(4,475)	61%	(28)%	**(10,426)**	(14,627)	(29)%
Operating	**(14,015)**	(13,733)	(14,332)	2%	(2)%	**(54,690)**	(51,002)	7%
General and administration	**(3,792)**	(3,365)	(4,259)	13%	(11)%	**(14,170)**	(13,585)	4%
Current income taxes	**(884)**	(6,913)	(2,348)	(87)%	(62)%	**(15,084)**	(10,556)	43%
Fund flows from operations	**51,980**	62,051	42,765	(16)%	22%	**219,451**	149,768	47%
Netbacks ($/boe)								
Sales	**84.02**	95.46	75.13	(12)%	12%	**89.44**	67.08	33%
Royalties	**(11.72)**	(12.08)	(10.11)	(3)%	16%	**(11.60)**	(7.15)	62%
Transportation	**(3.17)**	(1.91)	(4.27)	66%	(26)%	**(2.59)**	(3.66)	(29)%
Operating	**(13.71)**	(13.00)	(13.67)	5%	—%	**(13.56)**	(12.76)	6%
General and administration	**(3.71)**	(3.19)	(4.06)	16%	(9)%	**(3.51)**	(3.40)	3%
Current income taxes	**(0.86)**	(6.54)	(2.24)	(87)%	(62)%	**(3.74)**	(2.64)	42%
Fund flows from operations netback	**50.85**	58.74	40.78	(13)%	25%	**54.44**	37.47	45%
Reference prices								
Dated Brent (US $/bbl)	**67.76**	75.27	61.39	(10)%	10%	**71.04**	54.27	31%
Dated Brent ($/bbl)	**89.54**	98.37	78.05	(9)%	15%	**92.07**	70.44	31%

Production

- Q4 2018 production increased slightly from the prior quarter due continued strong performance from the 2018 Champotran wells and continued workover success in the Aquitaine Basin. Production increased 2% year-over-year primarily due to production additions from our 2018 drilling program.

Activity review

- Our 2018 capital program included the drilling and completion of two (2.0 net) Neocomian wells and three (3.0 net) Champotran wells in the first quarter of 2018. In addition to the drilling and completion activity, we continued our workover and optimization programs in the Aquitaine and Paris Basins throughout 2018.

Sales

- Crude oil in France is priced with reference to Dated Brent.
- Q4 2018 sales per boe decreased versus Q3 2018, consistent with the weakening in the Dated Brent reference price.
- For the three months and year ended December 31, 2018 versus the comparable periods in the prior year, the increase in sales per boe was consistent with increases in the Dated Brent benchmark price.

Royalties

- Royalties in France relate to two components: RCDM (levied on units of production and not subject to changes in commodity prices) and R31 (based on a percentage of sales).
- Royalties as a percentage of sales was 13.9% in Q4 2018 compared to 12.7% in Q3 2018. This increase was due the impact of fixed per-unit RCDM royalties relative to lower revenues resulting from weaker commodity prices.
- For the three months and year ended December 31, 2018, royalties as a percentage of sales of 13.9% and 13.0% increased from 13.5% and 10.7%, respectively, in the comparable periods in the prior year. These increases were due to the impact of a royalty rate increase enacted in 2017.

Transportation

- Transportation expense increased in Q4 2018 compared to Q3 2018 due to higher pipeline and terminal maintenance work performed in Q4 2018.
- Transportation expense for the three months and year ended December 31, 2018 decreased versus the comparable periods in the prior year, primarily due to the impact of IFRS 16 adoption in 2018. Please refer to "Recently Adopted Accounting Pronouncements" for additional information.

Operating

- Operating expense in Q4 2018 was relatively consistent with Q3 2018 and Q4 2017 on a dollar basis. On a per unit basis, operating expense increased in Q4 2018 versus Q3 2018 due to the impact of fixed costs on lower sales volumes, which was a result of shipment timing.
- For the year ended December 31, 2018, operating expense increased versus 2017 on both a dollar and per unit basis. These increases were primarily due to the impact of a stronger Euro versus the Canadian dollar, increased cost and usage of electricity, and higher maintenance activity in 2018.

General and administration

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

Current income taxes

- In France, current income taxes are applied to taxable income, after eligible deductions, at a statutory rate of 34.4%.
- Current income taxes for the year ended December 31, 2018 versus the comparative period were higher mainly due to higher Dated Brent prices resulting in increased sales.
- Current income taxes for Q4 2018 versus Q3 2018 and Q4 2017 were lower due to increased tax deductions for depletion.
- On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French corporate income tax rate from 34.4% to 25.8% by 2022, with the first reduction planned for 2019 to 32.0%.

Netherlands Business Unit

Overview

- Entered the Netherlands in 2004.
- Second largest onshore operator.
- Interests include 26 onshore licenses (all operated) and 17 offshore licenses (all non-operated).
- Licenses include more than 930,000 net acres of land, 90% of which is undeveloped.

Operational and financial review

Netherlands business unit ($M except as indicated)	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Production and sales								
Condensate (bbls/d)	**112**	84	105	33%	7%	**90**	90	—%
Natural gas (mmcf/d)	**51.82**	44.37	55.66	17%	(7)%	**46.13**	40.54	14%
Total (boe/d)	**8,749**	7,479	9,381	17%	(7)%	**7,779**	6,847	14%
Activity								
Capital expenditures	**2,454**	5,056	12,300	(51)%	(80)%	**17,483**	31,575	(45)%
Acquisitions	**(7,860)**	2,874	(38)			**(2,087)**	(24)	
Gross wells drilled	**—**	—	—			**—**	2.00	
Net wells drilled	**—**	—	—			**—**	1.02	
Financial results								
Sales	**52,937**	41,793	40,914	27%	29%	**165,916**	108,060	54%
Royalties	**(537)**	(1,049)	(647)	(49)%	(17)%	**(3,181)**	(1,722)	85%
Operating	**(6,765)**	(5,812)	(6,981)	16%	(3)%	**(26,681)**	(21,212)	26%
General and administration	**(709)**	(320)	(546)	122%	30%	**(1,947)**	(2,212)	(12)%
Current income taxes	**(7,492)**	1,729	6,975	N/A	N/A	**(16,561)**	3,331	N/A
Fund flows from operations	**37,434**	36,341	39,715	3%	(6)%	**117,546**	86,245	36%
Netbacks ($/boe)								
Sales	**65.77**	60.74	47.41	8%	39%	**58.44**	43.24	35%
Royalties	**(0.67)**	(1.52)	(0.75)	(56)%	(11)%	**(1.12)**	(0.69)	62%
Operating	**(8.40)**	(8.45)	(8.09)	(1)%	4%	**(9.40)**	(8.49)	11%
General and administration	**(0.88)**	(0.47)	(0.63)	87%	40%	**(0.69)**	(0.89)	(22)%
Current income taxes	**(9.31)**	2.51	8.08	N/A	N/A	**(5.83)**	1.33	N/A
Fund flows from operations netback	**46.51**	52.81	46.02	(12)%	1%	**41.40**	34.50	20%
Realized prices								
Condensate ($/bbl)	**69.95**	82.32	66.38	(15)%	5%	**74.85**	56.90	32%
Natural gas ($/mcf)	**10.95**	10.08	7.87	9%	39%	**9.71**	7.18	35%
Total ($/boe)	**65.77**	60.74	47.41	8%	39%	**58.44**	43.24	35%
Reference prices								
TTF ($/mcf)	**10.91**	10.92	8.36	—%	31%	**10.23**	7.43	38%
TTF (€/mcf)	**7.23**	7.18	5.58	1%	30%	**6.69**	5.07	32%

Production

- Q4 2018 production increased 17% from the prior quarter due to the contribution of a full quarter of production from the Eesveen-02 well (60% working interest), which we brought on production at a restricted rate of 10 mmcf/d net late in the third quarter of 2018. Production decreased 7% year-over-year primarily due to natural declines and permitting delays of certain drilling and workover activities, which impacted 2018 full-year volumes.

Activity review

- Our 2018 capital activity was primarily focused on planned workovers, facilities maintenance, and advancing our drilling permits ahead of our 2019 drilling campaign.
- In September 2018 we brought the Eesveen-02 well on production at a restricted rate of 10 mmcf/d net.
- In Q4 2018 we consolidated working interests on some of our existing assets and added minor working interest ownerships in several non-operated offshore licenses. The acquisition contributed approximately 200 boe/d to our Q4 2018 production results. Consideration for the acquisition required no cash payment but included the assumption of the full ARO associated with the incremental working interest. The ARO is estimated at a PV10 of €20 million. At closing we received a cash payment and positive working capital totaling €5.8 million due to the transaction having an effective date of January 1, 2018.

Sales

- The price of our natural gas in the Netherlands is based on the TTF index.
- Q4 2018 sales increased on a dollar basis versus Q3 2018 due to higher sales volumes coupled with increased TTF commodity pricing. Sales for the year ended December 31, 2018 increased versus the same period in the prior year due to the stronger TTF reference price in 2018, as well as an increase in sold volumes in 2018.
- For the three months and year ended December 31, 2018, sales per boe increased versus all comparable periods, consistent with increases in the TTF reference price.

Royalties

- In the Netherlands, certain wells are subject to overriding royalties while some wells are subject to royalties that take effect only when specified production levels are exceeded. As such, royalty expense may fluctuate from period to period depending on the amount of production from those wells. Royalties in the three months and year ended December 31, 2018 represented 1.0% and 1.9% of sales, respectively.

Transportation

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

Operating

- Q4 2018 operating expense increased on a dollar basis versus Q3 2018 due to a prior period adjustment booked in Q4 2018 relating to power usage, as well as increased permitting costs. On a per boe basis, operating expense was relatively consistent with the prior quarter as higher costs were offset by an increase in sales volumes. Operating expense on a per unit basis increased Q4 2018 versus Q4 2017 due to the impact of fixed costs over lower sales volumes.
- For the year ended December 31, 2018, operating expense increased on a dollar basis versus the comparable period in 2017 primarily due to increased maintenance activity coupled with an unfavourable foreign exchange impact. On a per unit basis, operating expense increased due to the strengthening of the Euro versus the Canadian Dollar.

General and administration

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

Current income taxes

- In the Netherlands, current income taxes are applied to taxable income, after eligible deductions and a 10% uplift deduction applied to operating expenses, eligible general and administration and tax deductions for depletion and asset retirement obligations, at a tax rate of 50%.
- Current income taxes in Q4 2018 and for the year ended December 31, 2018 versus the comparative periods were higher mainly due to higher TTF prices and volumes resulting in increased sales and an increased tax deduction taken in Q4 2017 for future asset retirement obligations resulting from a reduction in the applicable discount rate assumption.

- On December 18, 2018, the Dutch government approved the 2019 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% to 20.5% by 2021, with the first reduction planned for 2020 to 22.55%. Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not expected to have a material impact to Vermilion taxes in the Netherlands.

Germany Business Unit

Overview

- Entered Germany in 2014 through the acquisition of a non-operated natural gas producing property.
- Executed a significant exploration license farm-in agreement in 2015 and acquired operated producing properties in 2016.
- Producing assets consist of seven gas and eight oil producing fields with extensive infrastructure in place.
- Significant land position of approximately 1.2 million net acres (97% undeveloped).

Operational and financial review

Germany business unit ($M except as indicated)	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	**913**	1,019	1,148	(10)%	(20)%	**1,004**	1,060	(5)%
Natural gas (mmcf/d)	**16.94**	14.88	18.19	14%	(7)%	**15.66**	19.39	(19)%
Total (boe/d)	**3,736**	3,498	4,180	7%	(11)%	**3,614**	4,291	(16)%
Sales								
Crude oil (bbls/d)	**970**	929	1,067	4%	(9)%	**1,065**	993	7%
Natural gas (mmcf/d)	**16.94**	14.88	20.12	14%	(16)%	**15.66**	19.79	(21)%
Total (boe/d)	**3,794**	3,408	4,420	11%	(14)%	**3,675**	4,292	(14)%
Production mix (% of total)								
Crude oil	**24%**	29%	27%			**28%**	25%	
Natural gas	**76%**	71%	73%			**72%**	75%	
Activity								
Capital expenditures	**4,580**	6,497	5,279	(30)%	(13)%	**15,806**	9,531	66%
Acquisitions	**706**	959	—			**1,665**	—	
Financial results								
Sales	**21,897**	21,052	18,898	4%	16%	**82,449**	68,696	20%
Royalties	**(1,190)**	(2,448)	(1,798)	(51)%	(34)%	**(6,626)**	(6,655)	—%
Transportation	**(1,452)**	(1,191)	(1,164)	22%	25%	**(6,420)**	(6,207)	3%
Operating	**(6,615)**	(4,863)	(6,025)	36%	10%	**(23,048)**	(20,176)	14%
General and administration	**(2,308)**	(2,073)	(2,080)	11%	11%	**(7,401)**	(7,767)	(5)%
Fund flows from operations	**10,332**	10,477	7,831	(1)%	32%	**38,954**	27,891	40%
Netbacks ($/boe)								
Sales	**62.74**	67.15	50.22	(7)%	25%	**61.47**	44.37	39%
Royalties	**(3.41)**	(7.81)	(4.78)	(56)%	(29)%	**(4.94)**	(4.30)	15%
Transportation	**(4.16)**	(3.80)	(3.09)	9%	35%	**(4.79)**	(4.01)	19%
Operating	**(18.95)**	(15.51)	(16.01)	22%	18%	**(17.18)**	(13.03)	32%
General and administration	**(6.61)**	(6.61)	(5.53)	—%	20%	**(5.52)**	(5.02)	10%
Fund flows from operations netback	**29.61**	33.42	20.81	(11)%	42%	**29.04**	18.01	61%
Realized prices								
Crude oil ($/bbl)	**75.53**	92.45	72.58	(18)%	4%	**84.14**	63.91	32%
Natural gas ($/mcf)	**9.72**	9.61	7.07	1%	37%	**8.70**	6.38	36%
Total ($/boe)	**62.74**	67.15	50.22	(7)%	25%	**61.47**	44.37	39%
Reference prices								
Dated Brent (US $/bbl)	**67.76**	75.27	61.39	(10)%	10%	**71.04**	54.27	31%
Dated Brent ($/bbl)	**89.54**	98.37	78.05	(9)%	15%	**92.07**	70.44	31%
TTF ($/mcf)	**10.91**	10.92	8.36	—%	31%	**10.23**	7.43	38%
TTF (€/mcf)	**7.23**	7.18	5.58	1%	30%	**6.69**	5.07	32%

Production

- Q4 2018 production increased 7% from the prior quarter due to the restoration of a non-operated gas processing facility in the prior quarter, partially offset by other minor unplanned downtime events on our non-operated oil assets. Production decreased 11% year-over-year due to downtime at a non-operated gas processing plant that began in the middle of Q2 2018 and continued through the middle of Q3 2018.

Activity review

- Our 2018 capital program 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, which we expect to drill in 2019, in addition to performing workovers opportunities on our operated asset base.

Sales

- The price of our natural gas in Germany is based on the NCG and GPL indexes, which are both highly correlated to the TTF benchmark. Crude oil in Germany is priced with reference to Dated Brent.
- Sales per boe for Q4 2018 decreased versus Q3 2018, and increased versus the comparable periods in 2017, consistent with fluctuations in crude oil and natural gas benchmark prices.
- Sales per boe for 2018 increased versus 2017 due to the increase in crude oil and natural gas benchmark prices.

Royalties

- Our production in Germany is subject to state and private royalties on sales after certain eligible deductions.
- Royalties as a percentage of sales were lower in Q4 2018 versus Q3 2018 and Q4 2017 due to an annual rate adjustment recorded in Q4 2018. Royalties as a percentage of sales for the year ended December 31, 2018 were lower than the comparable period in the prior year due to increased production of crude oil with lower associated royalty rates.

Transportation

- Transportation expense in Germany relates to costs incurred to deliver natural gas from the processing facility to the customer and deliver crude oil to the refinery.
- Transportation expense in Q4 2018 was higher than Q3 2018 due to the impact of a favourable prior period adjustment recorded in Q3 2018. Transportation expense increased versus Q4 2017 due to higher volumes of crude oil transported in Q4 2018.
- Transportation expense for the year ended December 31, 2018 increased slightly versus the comparable period in the prior year due to higher tariffs on crude oil transport in 2018.

Operating

- Operating expense on a per unit basis in Q4 2018 was higher versus Q3 2018 due to higher activity levels at non-operated properties and increased gas processing fees.
- Operating expense on a per unit basis increased for the three months and year ended December 31, 2018, versus the comparable periods in the prior year. The increase was primarily due to increased gas processing tariffs, the impact of fixed costs on lower volumes and the impact of a stronger Euro versus the Canadian dollar.

General and administration

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

Current income taxes

- As a result of our tax pools in Germany, we do not expect to incur current income taxes for 2019 in the German Business Unit. This is subject to change in response to production variations, commodity price fluctuations, the timing of capital expenditures, and other eligible in-country adjustments.

Ireland Business Unit

Overview

- Entered Ireland in 2009 with an investment in the offshore Corrib gas field.
- The Corrib gas field is located offshore northwest Ireland and comprises six offshore wells, offshore and onshore sales and transportation pipeline segments, as well as a natural gas processing facility.
- In Q4 2018, Vermilion assumed operatorship of the Corrib Natural Gas Project (the "Corrib Project") and increased its ownership stake by 1.5% to 20% following the completion of a strategic partnership with Canada Pension Plan Investment Board ("CPPIB").

Operational and financial review

Ireland business unit ($M except as indicated)	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Production and sales								
Natural gas (mmcf/d)	**52.03**	51.38	56.23	1%	(7)%	**55.17**	58.43	(6)%
Total (boe/d)	**8,672**	8,563	9,372	1%	(7)%	**9,195**	9,737	(6)%
Activity								
Capital expenditures	**140**	(50)	327	N/A	(57)%	**224**	551	(59)%
Acquisitions	**(5,572)**	—	—			**(5,572)**	—	
Financial results								
Sales	**53,385**	50,228	43,793	6%	22%	**205,150**	153,330	34%
Transportation	**(1,115)**	(1,460)	(1,496)	(24)%	(25)%	**(5,129)**	(5,205)	(1)%
Operating	**(4,497)**	(3,354)	(2,977)	34%	51%	**(15,366)**	(17,596)	(13)%
General and administration	**(2,037)**	(3,597)	(517)	(43)%	294%	**(8,386)**	(2,320)	261%
Fund flows from operations	**45,736**	41,817	38,803	9%	18%	**176,269**	128,209	37%
Netbacks ($/boe)								
Sales	**66.91**	63.76	50.79	5%	32%	**61.12**	43.14	42%
Transportation	**(1.40)**	(1.85)	(1.74)	(24)%	(20)%	**(1.53)**	(1.46)	5%
Operating	**(5.64)**	(4.26)	(3.45)	32%	63%	**(4.58)**	(4.95)	(7)%
General and administration	**(2.55)**	(4.57)	(0.60)	(44)%	325%	**(2.50)**	(0.65)	285%
Fund flows from operations netback	**57.32**	53.08	45.00	8%	27%	**52.51**	36.08	46%
Reference prices								
NBP ($/mcf)	**11.03**	10.95	8.70	1%	27%	**10.35**	7.49	38%
NBP (€/mcf)	**7.31**	7.20	5.81	2%	26%	**6.76**	5.12	32%

Production

- Q4 2018 production increased 1% from the prior quarter primarily due to the production contribution from the closing of our acquisition of an additional 1.5% working interest in the Corrib Project. Production also benefited from the absence of maintenance downtime that had occurred in Q3 2018, which was partially offset by natural decline.

Activity review

- In December 2018, Vermilion acquired all of the issued and outstanding common shares of Shell E&P Ireland Limited, along with an incremental 1.5% working interest in the Corrib Project in Ireland from Nephin Energy Holdings Limited, a wholly owned subsidiary of CPPIB. The acquisition increased Vermilion's total ownership in Corrib to 20%. As part of this transaction, Vermilion assumed operatorship of the Corrib Project, providing us with day-to-day control over Corrib operations.

Sales

- The price of our natural gas in Ireland is based on the NBP index.
- Sales per boe for the three months and year ended December 31, 2018 increased versus all comparable periods consistent with increases in the NBP reference price.

Royalties

- Our production in Ireland is not subject to royalties.

Transportation

- Transportation expense in Ireland relates to payments under a ship-or-pay agreement related to the Corrib project.
- Transportation expense for the three months ended December 31, 2018 decreased versus Q3 2018 and Q4 2017 due to a decrease in tariffs in Q4 2018. For the year ended December 31, 2018, transportation expense was consistent with the comparable period in 2017.

Operating

- Q4 2018 operating expense was higher versus Q3 2018 and Q4 2017 due to an increase in offshore operations and terminal maintenance activity completed during Q4 2018.
- For the year ended December 31, 2018, operating expense was lower versus the comparable period in 2017 due to higher offshore maintenance activities which occurred in 2017.

General and administration

- The increase in general and administration expense versus all comparable periods is primarily due to transition costs associated with the aforementioned strategic partnership in Corrib.

Current income taxes

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

Australia Business Unit

Overview

- Entered Australia in 2005.
- Hold a 100% operated working interest in the Wandoo field, located approximately 80 km offshore on the northwest shelf of Australia.
- Production is operated from two off-shore platforms and originates from 20 producing wells including five dual lateral wells for a total of 25 producing laterals.
- Wells that utilize horizontal legs (ranging in length from 500 to 3,000 plus metres) are located 600m below the seabed in approximately 55m of water depth.

Operational and financial review

Australia business unit ($M except as indicated)	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Production								
Crude oil (bbls/d)	**4,174**	4,704	4,993	(11)%	(16)%	**4,494**	5,770	(22)%
Sales								
Crude oil (bbls/d)	**4,401**	3,935	4,707	12%	(7)%	**4,342**	5,717	(24)%
Inventory (mbbls)								
Opening crude oil inventory	**210**	139	108			**134**	115	
Crude oil production	**384**	433	459			**1,640**	2,106	
Crude oil sales	**(405)**	(362)	(433)			**(1,585)**	(2,087)	
Closing crude oil inventory	**189**	210	134			**189**	134	
Activity								
Capital expenditures	**43,760**	16,061	7,192	172%	508%	**75,638**	29,942	153%
Financial results								
Sales	**39,351**	35,848	36,086	10%	9%	**150,733**	154,391	(2)%
Operating	**(15,757)**	(11,585)	(12,172)	36%	29%	**(53,199)**	(50,139)	6%
General and administration	**(1,391)**	(1,020)	(3,193)	36%	(56)%	**(4,918)**	(8,194)	(40)%
Current income taxes	**2,206**	(3,101)	(5,327)	N/A	N/A	**(11,419)**	(24,355)	(53)%
Fund flows from operations	**24,409**	20,142	15,394	21%	59%	**81,197**	71,703	13%
Netbacks ($/boe)								
Sales	**97.19**	99.01	83.32	(2)%	17%	**95.11**	73.99	29%
Operating	**(38.92)**	(32.00)	(28.11)	22%	38%	**(33.57)**	(24.03)	40%
General and administration	**(3.44)**	(2.82)	(7.37)	22%	(53)%	**(3.10)**	(3.93)	(21)%
PRRT	**5.98**	0.70	(8.25)	754%	N/A	**(3.04)**	(9.50)	(68)%
Corporate income taxes	**(0.53)**	(9.27)	(4.05)	(94)%	(87)%	**(4.16)**	(2.17)	92%
Fund flows from operations netback	**60.28**	55.62	35.54	8%	70%	**51.24**	34.36	49%
Reference prices								
Dated Brent (US $/bbl)	**67.76**	75.27	61.39	(10)%	10%	**71.04**	54.27	31%
Dated Brent ($/bbl)	**89.54**	98.37	78.05	(9)%	15%	**92.07**	70.44	31%

Production

- Q4 2018 production decreased 11% quarter-over-quarter and 16% year-over-year due to a planned shutdown of the Wandoo field for maintenance and other well downtime, including that which was associated with drilling two new wells.
- Production volumes are managed within corporate targets while meeting customer demands and the requirements of long-term supply agreements.
- We continue to plan for long-term annual production levels of approximately 6,000 bbls/d.

Activity review

- In Q4 2018, we initiated our two (2.0 net) well drilling program, which was successfully completed in early 2019. The total cost of the program was $75 million, which was approximately $10 million over budget due to some minor drilling complications and weather-related delays.
- We also continued to focus on adding value through asset optimization and proactive maintenance.

Sales

- Crude oil in Australia is priced with reference to Dated Brent.
- Q4 2018 sales per boe were consistent with Q3 2018, but higher sales volumes resulted in an increase in sales quarter-over-quarter.
- Sales per boe for the three months and year ended December 31, 2018 increased versus the comparable periods in the prior year, consistent with increases in the Dated Brent reference price.

Royalties and transportation

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

Operating

- Q4 2018 operating expense increased versus Q3 2018 due to higher diesel usage and increased maintenance activity in Q4 2018.
- For the three months and year ended December 31, 2018, per unit operating expense increased versus the comparable periods in the prior year due to increased diesel usage and helicopter costs, coupled with the impact of fixed costs on lower volumes.

General and administration

- Fluctuations in general and administration expense for all comparable periods are primarily due to the timing of expenditures and allocations from our corporate segment. In addition, the decrease in general and administration expense for the three months and year ended December 31, 2018 versus the comparable periods in 2017 is primarily due to the impact of IFRS 16 adoption in 2018. As a result of this new accounting pronouncement, certain arrangements associated with office space in Australia have been accounted for as leases. Please refer to "Recently Adopted Accounting Pronouncements" for additional information.

Current income taxes

- In Australia, current income taxes include both PRRT and corporate income taxes. PRRT is a profit based tax applied at a rate of 40% on sales less eligible expenditures, including operating expenses and capital expenditures. Corporate income taxes are applied at a rate of 30% on taxable income after eligible deductions, which include PRRT paid.
- Current income taxes in Q4 2018 and for the year ended December 31, 2018 versus all comparative periods were lower mainly due to increased PRRT tax deductions for the Q4 2018 capital expenditures related to the drilling campaign.

United States Business Unit

Overview

- Entered the United States in September 2014.
- Interests include approximately 148,700 net acres of land (71% undeveloped) in the Powder River Basin of northeastern Wyoming.
- Tight oil development targeting the Turner Sands at depths of approximately 1,500m (East Finn) and 2,600m (Hilight).

Operational and financial review

United States business unit ($M except as indicated)	Q4 2018	Q3 2018	Q4 2017	Q4/18 vs. Q3/18	Q4/18 vs. Q4/17	2018	2017	2018 vs. 2017
Production and sales								
Crude oil (bbls/d)	**1,605**	1,461	667	10%	141%	**1,078**	666	62%
NGLs (bbls/d)	**998**	714	43	40%	2,221%	**452**	50	804%
Natural gas (mmcf/d)	**5.65**	4.82	0.29	17%	1,848%	**2.78**	0.39	613%
Total (boe/d)	**3,545**	2,979	758	19%	368%	**1,992**	781	155%
Production mix (% of total)								
Crude oil	**45%**	49%	88%			**54%**	85%	
NGLs	**28%**	24%	6%			**23%**	6%	
Natural gas	**27%**	27%	6%			**23%**	9%	
Activity								
Capital expenditures	**2,881**	11,386	1,018	(75)%	183%	**40,837**	19,074	114%
Acquisitions	**3,674**	187,987	91			**191,740**	3,403	
Gross wells drilled	**1.00**	—	—			**6.00**	3.00	
Net wells drilled	**1.00**	—	—			**6.00**	3.00	
Financial results								
Sales	**14,625**	14,551	4,350	1%	236%	**38,465**	15,355	151%
Royalties	**(4,053)**	(3,444)	(1,196)	18%	239%	**(10,070)**	(4,276)	136%
Transportation	**—**	—	(15)	—%	(100)%	**—**	(41)	(100)%
Operating	**(2,848)**	(2,633)	(397)	8%	617%	**(6,421)**	(1,698)	278%
General and administration	**(1,396)**	(2,397)	(1,274)	(42)%	10%	**(6,306)**	(4,341)	45%
Fund flows from operations	**6,328**	6,077	1,468	4%	331%	**15,668**	4,999	213%
Netbacks ($/boe)								
Sales	**44.85**	53.10	62.40	(16)%	(28)%	**52.90**	53.84	(2)%
Royalties	**(12.43)**	(12.57)	(17.16)	(1)%	(28)%	**(13.85)**	(14.99)	(8)%
Transportation	**—**	—	(0.21)	—%	(100)%	**—**	(0.14)	(100)%
Operating	**(8.73)**	(9.61)	(5.70)	(9)%	53%	**(8.83)**	(5.95)	48%
General and administration	**(4.28)**	(8.75)	(18.28)	(51)%	(77)%	**(8.67)**	(15.22)	(43)%
Fund flows from operations netback	**19.41**	22.17	21.05	(12)%	(8)%	**21.55**	17.54	23%
Realized prices								
Crude oil ($/bbl)	**70.78**	87.34	67.15	(19)%	5%	**79.18**	60.07	32%
NGLs ($/bbl)	**26.81**	29.22	41.25	(8)%	(35)%	**28.02**	25.11	12%
Natural gas ($/mcf)	**3.29**	2.01	2.48	64%	33%	**2.67**	2.05	30%
Total ($/boe)	**44.85**	53.10	62.40	(16)%	(28)%	**52.90**	53.84	(2)%
Reference prices								
WTI (US $/bbl)	**58.81**	69.50	55.40	(15)%	6%	**64.77**	50.95	27%
WTI ($/bbl)	**77.71**	90.83	70.43	(14)%	10%	**83.94**	66.13	27%
Henry Hub (US $/mcf)	**3.65**	2.90	2.93	26%	25%	**3.09**	3.11	(1)%
Henry Hub ($/mcf)	**4.82**	3.80	3.73	27%	29%	**4.01**	4.04	(1)%

Production

- Q4 2018 production increased 19% from the prior quarter and 368% year-over-year primarily due to the production associated with an acquisition we completed in August 2018.

Activity

- In August 2018, we acquired all of the assets of a private oil company in the Powder River Basin for total cash consideration of approximately $189 million. The assets are located in Campbell County, Wyoming, approximately 40 miles (65 kilometres) northwest of Vermilion's existing operations. The assets included 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%.
- Our 2018 drilling program consisted of the drilling and completion of five (5.0 net) wells on our East Finn asset, along with the drilling and completion of one (1.0 net) well on our recently acquired Hilight asset, both located in the Powder River Basin.

Sales

- The price of crude oil in the United States is directly linked to WTI, subject to local market differentials within the United States.
- Q4 2018 sales per boe decreased versus Q3 2018 consistent with the decrease in crude oil pricing.
- Q4 2018 sales per boe decreased versus Q4 2017 due to an increase in natural gas production from assets acquired in 2018. For the year ended December 31, 2018, sales per boe remained relatively stable versus the comparable period in 2017. This was due to the strengthening of WTI reference pricing offset by the increase in gas production from newly acquired assets.

Royalties

- Our production in the United States is subject to federal and private royalties, severance tax, and ad valorem tax.
- Royalties as a percentage of sales were higher in Q4 2018 versus Q3 2018 due to the impact of a favourable prior period adjustment recorded in Q3 2018, which also reduced royalties as a percentage of sales for 2018 versus 2017.

Operating

- Fluctuations in operating expense versus all comparable periods were due to the timing of maintenance activity and incremental costs from the assets acquired in Q3 2018.

General and administration

- Fluctuations in general and administration expense for all comparable periods were due to the incremental staffing of the United States corporate office, timing of expenditures and allocations from our corporate segment.

Current income taxes

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

Corporate

Overview

- Our Corporate segment includes costs related to our global hedging program, financing expenses, and general and administration expenses that are primarily incurred in Canada and are not directly related to the operations of our business units. Gains or losses relating to Vermilion's global hedging program are allocated to Vermilion's business units for statutory reporting and income tax purposes.
- Results of our activities in Central and Eastern Europe are also included in the Corporate segment, including production, revenues, and expenditures relating to our first exploratory well in the South Battonya concession in Hungary.

Operational and financial review

Corporate ($M)	Q4 2018	Q3 2018	Q4 2017	2018	2017
Production and sales					
Natural gas (mmcf/d)	**2.86**	1.17	—	**1.02**	—
Total (boe/d)	**477**	195	—	**169**	—
Activity					
Capital expenditures	**2,546**	1,619	1,295	**10,611**	7,728
Acquisitions	**(492)**	207	2,207	**(285)**	2,247
Gross wells drilled	**—**	—	—	**1.00**	—
Net wells drilled	**—**	—	—	**1.00**	—
Financial results					
Sales	**2,547**	1,083	—	**3,630**	—
Royalties	**(534)**	(279)	—	**(813)**	—
Operating	**—**	(201)	—	**(110)**	—
General and administration recovery (expense)	**969**	854	(1,532)	**(2,744)**	(6,350)
Current income taxes	**646**	(862)	(542)	**(513)**	(527)
Interest expense	**(20,827)**	(19,772)	(13,710)	**(72,759)**	(57,313)
Realized (loss) gain on derivatives	**(28,319)**	(37,365)	(7,493)	**(111,258)**	4,721
Realized foreign exchange gain (loss)	**5,894**	(3,100)	2,899	**243**	2,316
Realized other income	**275**	177	166	**883**	674
Fund flows from operations	**(39,258)**	(59,465)	(20,212)	**(183,441)**	(56,479)

Production review

- Production in our Central and Eastern Europe business unit averaged 477 boe/d in Q4 2018 representing the first full quarter of gas production for the business unit from our South Battonya concession in Hungary.

Activity review

- In 2018, we brought on production our first exploratory well (100% working interest) in the South Battonya concession of Hungary, which we drilled and tested in the first quarter of 2018. We also continued to prepare for our 2019 drilling campaigns in Hungary, Slovakia and Croatia. Other exploration activities performed through 2018 included the acquisition of 2D seismic data in Croatia, further interpretation of 3D seismic data in Hungary, and expanding our land position in Slovakia.

General and administration

- Fluctuations in general and administration expense for the three months and year ended December 31, 2018 versus all comparable periods were due to allocations to the various business unit segments.

Current income taxes

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

Interest expense

- The increase in interest expense in Q4 2018 versus Q3 2018 was due to higher drawings on the revolving credit facility.
- For the three months and year ended December 31, 2018, interest expense increased versus the comparative periods in 2017 due to the impact of higher drawings on the revolving credit facility, as well as the impact of IFRS 16 adoption in 2018. Please refer to "Recently Adopted Accounting Pronouncements" for additional information regarding the adoption of IFRS 16.

Realized gain or loss on derivatives

- The realized loss on derivatives for the year ended December 31, 2018 is related primarily to amounts paid on crude oil and European natural gas hedges.
- A listing of derivative positions as at December 31, 2018 is included in “Supplemental Table 2” of this MD&A.

Financial Performance Review

($M except per share)	Dec 31, 2018	Dec 31, 2017	Dec 31, 2016
Total assets	**6,270,671**	3,974,965	4,087,184
Long-term debt	**1,796,207**	1,270,330	1,362,192
Petroleum and natural gas sales	**1,678,117**	1,098,838	882,791
Net earnings (loss)	**271,650**	62,258	(160,051)
Net earnings (loss) per share			
Basic	**1.93**	0.52	(1.38)
Diluted	**1.91**	0.51	(1.38)
Cash dividends ($/share)	**2.72**	2.58	2.58

($M except per share)	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Petroleum and natural gas sales	**456,939**	508,411	394,498	318,269	317,341	248,505	271,391	261,601
Net earnings (loss)	**323,373**	(15,099)	(61,364)	24,740	8,645	(39,191)	48,264	44,540
Net earnings (loss) per share								
Basic	**2.12**	(0.10)	(0.46)	0.20	0.07	(0.32)	0.40	0.38
Diluted	**2.10**	(0.10)	(0.46)	0.20	0.07	(0.32)	0.39	0.37

The following table shows the calculation of fund flows from operations:

	Q4 2018		Q3 2018		Q4 2017		2018		2017	
	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe	$M	$/boe
Petroleum and natural gas sales	**456,939**	**48.90**	508,411	57.90	317,341	47.49	**1,678,117**	**52.95**	1,098,838	44.41
Royalties	**(43,874)**	**(4.70)**	(53,786)	(6.13)	(23,541)	(3.52)	**(152,167)**	**(4.80)**	(74,476)	(3.01)
Petroleum and natural gas revenues	**413,065**	**44.20**	454,625	51.77	293,800	43.97	**1,525,950**	**48.15**	1,024,362	41.40
Transportation	**(16,938)**	**(1.81)**	(13,721)	(1.56)	(11,986)	(1.79)	**(51,887)**	**(1.64)**	(43,448)	(1.76)
Operating	**(112,470)**	**(12.04)**	(97,758)	(11.13)	(65,240)	(9.76)	**(357,014)**	**(11.26)**	(242,267)	(9.79)
General and administration	**(12,814)**	**(1.37)**	(13,234)	(1.51)	(15,941)	(2.39)	**(51,929)**	**(1.64)**	(54,373)	(2.20)
PRRT	**2,422**	**0.26**	254	0.03	(3,572)	(0.53)	**(4,824)**	**(0.15)**	(19,819)	(0.80)
Corporate income taxes	**(7,946)**	**(0.85)**	(9,401)	(1.07)	2,330	0.35	**(38,753)**	**(1.22)**	(12,288)	(0.50)
Interest expense	**(20,827)**	**(2.23)**	(19,772)	(2.25)	(13,710)	(2.05)	**(72,759)**	**(2.30)**	(57,313)	(2.32)
Realized (loss) gain on derivative instruments	**(28,319)**	**(3.03)**	(37,365)	(4.26)	(7,493)	(1.12)	**(111,258)**	**(3.51)**	4,721	0.19
Realized foreign exchange loss	**5,894**	**0.63**	(3,100)	(0.35)	2,899	0.43	**243**	**0.01**	2,316	0.09
Realized other income	**275**	**0.03**	177	0.02	166	0.02	**883**	**0.03**	674	0.03
Fund flows from operations	**222,342**	**23.79**	260,705	29.69	181,253	27.13	**838,652**	**26.47**	602,565	24.34

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

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

	Q4 2018	Q3 2018	Q4 2017	2018	2017
Fund flows from operations	**222,342**	260,705	181,253	**838,652**	602,565
Equity based compensation	**(16,979)**	(13,056)	(16,087)	**(60,746)**	(61,579)
Unrealized gain (loss) on derivative instruments	**273,096**	(75,829)	(80,012)	**109,326**	(1,062)
Unrealized foreign exchange (loss) gain	**(36,366)**	(23,044)	40,660	**(63,243)**	71,742
Unrealized other expense	**(204)**	(203)	(197)	**(801)**	(637)
Accretion	**(8,205)**	(8,041)	(6,991)	**(31,219)**	(26,971)

Depletion and depreciation	**(174,435)**	(166,343)	(129,179)	**(609,056)**	(491,683)
Deferred tax	**(64,084)**	10,712	19,198	**(39,471)**	(30,117)
Gain on business combinations	**128,208**	—	—	**128,208**	—
Net earnings	**323,373**	(15,099)	8,645	**271,650**	62,258

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

Equity based compensation

Equity based compensation expense relates primarily to non-cash compensation expense attributable to long-term incentives granted to directors, officers, and employees under security-based arrangements, including the Vermilion Incentive Plan ("VIP") and a security-based compensation arrangement ("Five-Year Compensation Arrangement").

Equity based compensation expense increased in Q4 2018 compared to Q3 2018 and Q4 2017, primarily due to a higher number of outstanding share awards in Q4 2018. For the year ended December 31, 2018, equity based compensation was relatively consistent versus the comparable period in 2017.

Unrealized gain or loss on derivative instruments

Unrealized gain or loss on derivative instruments arise as a result of changes in future commodity price forecasts. As Vermilion uses derivative instruments to manage the commodity price exposure of our future crude oil and natural gas production, we will normally recognize unrealized gains on derivative instruments when future commodity price forecasts decline and vice-versa. As derivative instruments are settled, the unrealized gain or loss previously recognized is reversed, and the settlement results in a realized gain or loss on derivative instruments.

For the three months and year ended December 31, 2018, we recognized unrealized gains on derivative instruments of $273.1 million and $109.3 million, respectively. The unrealized gains primarily related to European natural gas and crude oil derivative instruments for 2019 through 2021.

Unrealized foreign exchange gains or losses

As a result of Vermilion's international operations, Vermilion has monetary assets and liabilities denominated in currencies other than the Canadian dollar. These monetary assets and liabilities include cash, receivables, payables, long-term debt, derivative instruments and intercompany loans. These monetary assets primarily relate to Euro denominated intercompany loans from Vermilion Energy Inc. to our international subsidiaries. These monetary liabilities primarily relate to our US$300.0 million senior unsecured notes.

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

For the three months and year ended December 31, 2018, the impact of the Canadian dollar weakening against the US dollar was more significant than the impact of the Canadian dollar weakening against the Euro, resulting in unrealized losses on foreign exchange of $36.4 million and $63.2 million, respectively.

As at December 31, 2018, a $0.01 appreciation of the Euro against the Canadian dollar would result in a $2.2 million increase to net earnings as a result of an unrealized gain on foreign exchange. In contrast, a $0.01 appreciation of the US dollar against the Canadian dollar would result in a $3.0 million decrease to net earnings as a result of an unrealized loss on foreign exchange.

Accretion

Accretion expense is recognized to update the present value of the asset retirement obligation balance. The increase in accretion expense for the three months and year ended December 31, 2018 versus the comparable periods in 2017 was primarily attributable to new obligations recognized following acquisitions in 2018. For the three months ended December 31, 2018, accretion expense was relatively consistent with the prior quarter.

Depletion and depreciation

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

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

Depletion and depreciation on a per boe basis for the year ended December 31, 2018 of $19.22 was slightly lower than the $19.87 per boe rate in 2017, despite a significant increase in higher cost crude oil production and an increase in depreciation expense following the recognition of right-of-use assets under IFRS 16 due to continued increases in our proved plus probable reserves.

Deferred tax

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

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

For the three months and year ended December 31, 2018, deferred tax expense of $64.1 million and $39.5 million were primarily attributable to unrealized gains on derivative instruments and the accelerated deduction of capital expenditures incurred on the drilling program in Australia for PRRT purposes (which decreased PRRT expense but correspondingly increased deferred tax expense). These taxable temporary differences were partially offset by the recognition of additional tax losses in Ireland that are expected to be utilized due to higher European natural gas pricing forecasts.

Taxes

Current income tax rates

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

For 2018 and 2017, taxable income was subject to corporate income tax at the following rates:

Jurisdiction	2018	2017
Canada	27.0%	27.0%
France	34.4%	34.4%
Netherlands (1)	50.0%	50.0%
Germany (2)	30.2%	26.3%
Ireland	25.0%	25.0%
Australia	30.0%	30.0%
United States	21.0%	35.0%

(1) In the Netherlands, an additional 10% uplift deduction is allowed against taxable income that is applied to operating expenses, eligible general and administration expenses and tax deductions for depletion and abandonment retirement obligations.
(2) In 2018, the German Business Unit moved its central office to a new German municipality with a higher trade tax rate.

Tax legislation changes

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

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

On December 18, 2018, the Dutch government approved the 2019 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% to 20.5% by 2021, with the first reduction planned for 2020 to 22.55%. Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not expected to have a material impact to Vermilion taxes in the Netherlands.

Tax pools

As at December 31, 2018, we had the following tax pools:

($M)	Oil & Gas Assets	Tax Losses	Other	Total
Canada	2,317,044(1)	1,052,664(4)	36,192	3,405,900
France	317,062(2)	11,086(5)	—	328,148
Netherlands	66,947(3)	—	—	66,947
Germany	175,756(3)	98,787(6)	11,932	286,475
Ireland	—	1,301,395(4)	—	1,301,395
Australia	298,054(1)	10,486(4)	—	308,540

United States	214,965[(1)]	101,928[(7)]	10,184	327,077
Total	**3,389,828**	**2,576,346**	**58,308**	**6,024,482**

(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

Financial Position Review

Balance sheet strategy

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

To ensure that we maintain a conservative balance sheet, we monitor the ratio of net debt to fund flows from operations.

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

Due to the timing of payments on our fourth quarter drilling activity in Canada and Australia, we had a working capital deficit of $133.3 million as at December 31, 2018. Vermilion intends to fund this working capital deficiency through fund flows from operations generated in 2019 and unutilized capacity on our revolving credit facility.

Net debt

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

	As at	
($M)	**Dec 31, 2018**	**Dec 31, 2017**
Long-term debt	**1,796,207**	1,270,330
Current liabilities	**563,199**	363,306
Current assets	**(429,877)**	(261,846)
Net debt	**1,929,529**	1,371,790
Ratio of net debt to quarterly annualized fund flows from operations	**2.17**	1.89
Ratio of net debt to fund flows from operations	**2.30**	2.28

As at December 31, 2018, net debt increased to $1.93 billion (December 31, 2017 - $1.37 billion) due to the impact of the acquisitions closed in 2018. This increase was partially offset by a $115.6 million decrease in net current derivative liability and an increase in fund flows from operations, which resulted in an increase in the ratio of net debt to fund flows from operations from 2.28 for 2017 to 2.30 for 2018.

Year-end net debt to fund flows from operations of 2.30 compares to our previous forecast of year end net debt to fund flows from operations of 1.7 times as announced in our press release on April 16, 2018 ("Vermilion Energy Inc. Announces Acquisition of Spartan Energy Corp."). The increase in the ratio of net debt to fund flows from operations from forecast resulted from a decrease in crude oil prices in Q4 2018 and incremental debt assumed on our acquisition in the United States in Q3 2018.

Long-term debt

The balances recognized on our balance sheet are as follows:

($M)	As at Dec 31, 2018	Dec 31, 2017
Revolving credit facility	**1,392,206**	899,595
Senior unsecured notes	**404,001**	370,735
Long-term debt	**1,796,207**	1,270,330

Revolving Credit Facility

In Q2 2018, we negotiated an increase in our revolving credit facility from $1.4 billion to $1.6 billion and an extension of the maturity from May 31, 2021 to May 31, 2022. In Q3 2018, we negotiated a further increase in our revolving credit from $1.6 billion to $1.8 billion.

Subsequent to December 31, 2018, we negotiated an additional increase in our revolving credit facility from $1.8 billion to $2.1 billion. This additional debt capacity provides us with additional working capital and operational flexibility. There were no changes to the facility maturity date or applicable covenants as a result of this increase.

As at December 31, 2018, Vermilion had in place a bank revolving credit facility maturing May 31, 2022 with terms, outstanding positions, and covenants. as follows:

	As at	
($M)	**Dec 31, 2018**	**Dec 31, 2017**
Total facility amount	**1,800,000**	1,400,000
Amount drawn	**(1,392,206)**	(899,595)
Letters of credit outstanding	**(15,400)**	(7,400)
Unutilized capacity	**392,394**	493,005

As at December 31, 2018, the revolving credit facility was subject to the following covenants:

		As at	
Financial covenant	**Limit**	**Dec 31, 2018**	**Dec 31, 2017**
Consolidated total debt to consolidated EBITDA	4.0	**1.72**	1.87
Consolidated total senior debt to consolidated EBITDA	3.5	**1.34**	1.30
Consolidated total senior debt to total capitalization	55%	**30%**	32%

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

- Consolidated total debt: Includes all amounts classified as “Long-term debt”, “Current portion of long-term debt”, and “Lease obligations” (including the current portion included within "Accounts payable and accrued liabilities" but excluding operating leases as defined under IAS 17) on our balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certain other non-cash items, adjusted for the impact of the acquisition of a material subsidiary.
- Total capitalization: Includes all amounts on our balance sheet classified as “Shareholders’ equity” plus consolidated total debt as defined above.

Senior Unsecured Notes

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

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

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

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

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

Shareholders' capital

Beginning with the April 2018 dividend paid on May 15, 2018, we increased our monthly dividend by 7%, to $0.23 per share from $0.215 per share. The dividend increase in Q2 2018 was our fourth dividend increase (previously Vermilion's distribution in the income trust era) since we began paying a distribution in 2003.

In total, dividends declared in 2018 were $388.1 million.

The following table outlines our dividend payment history:

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

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

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

The following table reconciles the change in shareholders’ capital:

Shareholders’ Capital	Number of Shares ('000s)	Amount ($M)
Balance at December 31, 2017	**122,119**	**2,650,706**
Shares issued for corporate acquisition	**27,883**	**1,234,676**
Shares issued for the Dividend Reinvestment Plan	**1,179**	**49,051**
Vesting of equity based awards	**1,025**	**54,057**
Equity based compensation	**314**	**12,565**
Share-settled dividends on vested equity based awards	**184**	**7,773**
Balance as at December 31, 2018	**152,704**	**4,008,828**

As at December 31, 2018, there were approximately 1.9 million equity based compensation awards outstanding. As at February 27, 2019, there were approximately 152.8 million common shares issued and outstanding.

Contractual Obligations and Commitments

As at December 31, 2018, we had the following contractual obligations and commitments:

($M)	Less than 1 year	1 - 3 years	3 - 5 years	After 5 years	Total
Long-term debt [1]	78,604	157,208	1,435,616	443,791	2,115,219
Lease obligations	30,798	49,743	34,313	42,739	157,593
Processing and transportation agreements	25,844	24,835	10,902	34,371	95,952
Purchase obligations	33,223	16,223	1,379	—	50,825
Drilling and service agreements	26,667	28,933	41,976	5,301	102,877
Total contractual obligations and commitments	195,136	276,942	1,524,186	526,202	2,522,466

(1) Interest on revolving credit facility calculated assuming an annual interest rate of 4%.

Asset Retirement Obligations

As at December 31, 2018, asset retirement obligations were $650.2 million compared to $517.2 million as at December 31, 2017.

The increase in asset retirement obligations is largely attributable to additional obligations recognized as a result of acquisitions completed in 2018.

Risks and Uncertainties

Crude oil and natural gas exploration, production, acquisition and marketing operations involve a number of risks and uncertainties that have affected the financial statements and are reasonably likely to affect them in the future. These risks and uncertainties are discussed further below.

Commodity prices

Crude oil and natural gas prices have fluctuated significantly in recent years due to supply and demand factors. Changes in crude oil and natural gas prices affect the level of revenue we generate, the amount of proceeds we receive and payments we make on our commodity derivative instruments, and the level of taxes that we pay. In addition, lower crude oil and natural gas prices would reduce the recoverable amount of our capital assets and could result in impairments or impairment reversals.

Exchange rates

Exchange rate changes impact the Canadian dollar equivalent revenue and costs that we recognize. The majority of our crude oil and condensate revenue stream is priced in US dollars and as such an increase in the strength of the Canadian dollar relative to the US dollar would result in the receipt of fewer Canadian dollars for our revenue. We also incur expenses and capital costs in US dollars, Euros and Australian dollars and thus a decrease in strength of the Canadian dollar relative to those currencies may result in the payment of more Canadian dollars for our expenditures.

In addition, exchange rate changes impact the Canadian equivalent carrying balances for our assets and liabilities. For foreign currency denominated monetary assets (such as cash and cash equivalents, long-term debt, and intercompany loans), the impact of changes in exchange rates is recorded in net earnings as a foreign exchange gain or loss.

Production and sales volumes

Our production and sales volumes affect the level of revenue we generate and correspondingly the royalties and taxes that we pay. In addition, significant declines in production or sales volumes due to unforeseen circumstances, may also result in an indicator of impairment and potential impairment charges.

Interest rates

Changes in interest rates impact the amount of interest expense we pay on our variable rate debt and also our ability to obtain fixed rate financing in the future.

Tax and royalty rates

Changes in tax and royalty rates in the jurisdictions that we operate in would impact the amount of current taxes and royalties that we pay. In addition, changes to substantively enacted tax rates would impact the carrying balance of deferred tax assets and liabilities, potentially resulting in a deferred tax recovery or incremental deferred tax expense.

In addition to the above, we are exposed to risk factors that impact our company and business. For further information on these risk factors, please refer to our Annual Information Form, available on SEDAR at www.sedar.com or on our website at www.vermilionenergy.com.

Financial Risk Management

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

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

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

Critical Accounting Estimates

The preparation of financial statements in accordance with IFRS requires us to make estimates. Critical accounting estimates are those accounting estimates that require us to make assumptions about matters that are highly uncertain at the time the estimate is made and a different estimate could have been made in the current period or the estimate could change period-to-period.

The carrying amount of asset retirement obligations

The carrying amount of asset retirement obligations ($650.2 million as at December 31, 2018) is the present value of estimated future costs, discounted from the estimated abandonment date using a credit-adjusted risk-free rate. Estimated future costs are based on our assessment of regulatory requirements and the present condition of our assets. The estimated abandonment date is based on the reserve life of the associated assets. The credit-adjusted risk-free rate is based on prevailing interest rates for appropriate term, risk-free government bonds adjusted for our estimated credit spread (determined by reference to the trading prices for debt issued by similarly rated independent oil and gas producers, including our own senior unsecured notes). Changes in these estimates would result in a change in the carrying amount of asset retirement obligations and capital assets and, to a significantly lesser degree, future accretion and depletion expense.

The estimated abandonment date may change from period to period as the estimated abandonment date changes in response to new information, such as changes in reserve life assumptions or regulations. A one year increase or decrease in the estimated abandonment date would decrease or increase asset retirement obligations (with an offsetting increase to capital assets) by approximately $25.0 million.

The estimated credit-adjusted risk-free rate may change from period to period in response to market conditions in Canada and the international jurisdictions that we operate in. An 0.5% increase or decrease in the credit-adjusted risk-free rate would decrease or increase asset retirement obligations by approximately $55.0 million.

The recognition of deferred tax assets in Ireland

In Ireland, we have $0.5 billion of non-expiring tax loss pools where $127.9 million of deferred tax assets has not been recognized as there is uncertainty on our ability to fully use these losses based on estimated future taxable profits. Estimated future taxable profits are calculated using proved and probable reserves and forecast pricing for European natural gas.

As a result, the carrying value of deferred tax assets may change from period-to-period due to changes in forecast pricing for European natural gas. A 5% increase or decrease in proved and probable reserves in our Ireland segment would increase or decrease deferred tax assets (with a corresponding deferred tax recovery or expense) by approximately $17.0 million. A €0.50/GJ increase or decrease in forecast European natural gas prices would increase or decrease deferred tax assets (with a corresponding deferred tax recovery or expense) by approximately $26.0 million.

The amount of finance lease obligations recognized on adoption of IFRS 16

Effective January 1, 2018, Vermilion adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a $97.1 million increase to lease obligations with a corresponding increase to right-of-use assets. The amount of lease obligation (and therefore the amount of right-of-use assets) recognized was calculated as the present value of future lease payments, discounted using our estimated incremental borrowing rate. The estimated incremental borrowing rate reflects the interest rate we would estimate receiving to borrow funds for a similar term and security to acquire the right-of-use asset. Changes in the estimated incremental borrowing rate would change the amount of lease obligations and right-of-use assets recognized on initial adoption and, to a significantly lesser degree, would impact future interest expense and depreciation expense. Based on attributes of our identified leases (including the term of the lease and the country the asset is leased in), we applied a weighted average incremental borrowing rate of 5.4%. A 1% increase or decrease in the estimated incremental borrowing rate would have decreased or increased lease obligations and right-of-use assets recognized on initial adoption by approximately $4.0 million.

The fair value of capital assets acquired in business combinations

In preparing the purchase price allocations for the business combinations completed in 2018, we estimate the fair value of assets acquired. Assets acquired in an acquisition primarily relates to the crude oil and natural gas reserves. The estimated fair value of the crude oil and natural gas reserves acquired is based on the present value of proved plus probable reserves and forecast commodity prices. Changes in these assumptions would change the amount of capital assets recognized and as a result would also impact any goodwill or gain recognized on the acquisition and future depletion and depreciation expense.

The estimated recoverable amount of cash generating units

Each reporting period, we assess our cash generating units for indicators of impairment or impairment reversal. If an indicator of impairment or impairment reversal is identified, we estimate the recoverable amount of the cash generating unit. During the years ended December 31, 2017 and 2018, no indicators of impairment were identified. As a result, the recoverable amount of cash generating units were not critical accounting estimates.

Off Balance Sheet Arrangements

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

Recently Adopted Accounting Pronouncements

IFRS 9 "Financial Instruments"

On January 1, 2018, Vermilion adopted IFRS 9 *"Financial Instruments"* as issued by the IASB. IFRS 9 includes a new classification and measurement approach for financial assets and a forward-looking 'expected credit loss' model. The adoption of IFRS 9 did not have a material impact on Vermilion's consolidated financial statements.

IFRS 15 "Revenue from contracts with customers"

On January 1, 2018, Vermilion adopted IFRS 15 "Revenue from Contracts with Customers" IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Vermilion's revenue relates to the sale of petroleum and natural gas to customers at specified delivery points at benchmark prices.

Vermilion adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15.

IFRS 16 "Leases"

IFRS 16 "Leases" is required to be applied on or after January 1, 2019. The stated objective of IFRS 16 is to provide information that faithfully represents lease transactions and provides a basis for users of financial statements to assess the amount, timing and uncertainty of cash flows arising from leases. IFRS 16 accomplishes this by introducing a single lessee accounting model that requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases. As the Company completed the assessment of the standard and applicable contracts during Q3 2018, Vermilion elected for earlier application of IFRS 16 to achieve the stated objectives of the standard and to increase comparability of results in future periods. Vermilion began applying the standard effective January 1, 2018.

Effective January 1, 2018, Vermilion applied IFRS 16 retrospectively with the cumulative effect of initially applying the standard recognized as a $97.1 million increase to right-of-use assets (included in "Capital assets") and lease obligations ($86.1 million recorded in "Lease obligations" and $11.0 million recorded in "Accounts payable and accrued liabilities"). The right-of-use assets and lease obligations recognized largely relate to the Company's head office lease in Calgary and long-term leases for oil storage facilities in France.

Health, Safety and Environment

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

We maintain health, safety and environmental practices and procedures in compliance with or exceeding regulatory requirements and industry standards. All of our personnel are expected to work safely and in accordance with established regulations and procedures, and we seek to reduce impacts to land, water and air. During 2018 we:

- Maintained clear priorities around 5 key focus areas of HSE Culture, Communication and Knowledge Management, Technical Safety Management, Incident Prevention and Operational Stewardship & Sustainability;
- Continued comprehensive investigations of our incidents and near misses to ensure root causes were identified and corrective actions effectively implemented;
- Completed and gained regulatory acceptance of the Corrib Production Safety Case;
- Completed maturity assessments of the HSE MS elements for each business unit;
- Received ISO 5001 certification for the German Business Unit energy management program;

- Completed numerous corporate policy/standard audits/assessments related to operational risk management, contractor management, marine transportation and drug and alcohol;
- Implemented “Vermilion High 5”, an individual safety awareness initiative aimed at keeping front line workers safe;
- Further developed and validated critical procedures and implemented fit-for-purpose training and competency programs;
- Implemented a comprehensive HSE integration plan for Vermilion’s new and emerging operations (includes Central and Eastern Europe, Germany, United States, Ireland and Canada expansion);
- Reported our CO2e emissions to the CDP highlighting the implementation of 40 projects that reduced our gross emissions by 15,000 tonnes CO2e while increasing production;
- Completed and published our Corporate Sustainability Report with emphasis on improving energy efficiency, greenhouse gas emissions reduction and water efficiency optimization;
- Managed our waste products by reducing, recycling and recovering;
- Reduced long-term environmental liabilities through decommissioning, abandoning and reclaiming well leases and facilities;
- Further refined and expanded our enterprise wide corporate risk register;
- Expanded our company-wide HSE leadership training program to improve hazard identification and risk reduction;
- Continued the development of a robust hazard identification and risk mitigation program specific to environmentally sensitive areas;
- Continued the development of our Corporate Process Safety Management System with emphasis on Process Hazards Analysis and risk reduction measures;
- Performed auditing, management inspections and workforce observations to measure compliance and identify potential hazards and apply risk reduction measures; and
- Developed, communicated and measured against leading and lagging HSE key performance indicators;

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

Environmental, Social and Governance (ESG)

Furthering our focus on sustainability (ESG) strategy, in 2018 we reviewed recommendations from the Task Force on Climate-related Financial Disclosures (TCFD). We subsequently updated our sustainability reporting in general to illustrate Vermilion’s alignment with these recommendations, focusing on climate, but also on sustainability issues and opportunities in a wider context. In 2018, our Board of Directors also established a Sustainability Committee to provide further support on issues related to sustainability, including climate. Our 2018 performance in sustainability rankings such as CDP, RobecoSAM and Sustainalytics continued to be top of our peer group.

Sustainability

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

Vermilion understands our stakeholders’ expectations that we deliver strong financial results in a responsible and ethical way. As a result, we align our strategic priorities in the following order:

- the safety and health of our staff and those involved directly or indirectly in our operations;
- our responsibility to protect the environment. We follow the Precautionary Principle introduced in 1992 by the United Nations "Rio Declaration on Environment and Development" by using environmental risk as part of our development decision criteria, and by continually seeking improved environmental performance in our operations; and
- economic success through a focus on operational excellence across our business, which includes technical and process excellence, efficiency, expertise, stakeholder relations, and respectful and fair treatment of staff, contractors, partners and suppliers.

Reflecting these priorities, we have positioned Vermilion purposefully within the energy transition. Predictions differ about the manner and speed of the transition, but our own scenario analyses are clear that Vermilion can best contribute by focusing on producing energy responsibly: reliably, cost-effectively and safely. We also believe those stakeholders who are concerned about sustainability, including investors, governments, regulators, communities and citizens, should turn to best-in-class operators such as Vermilion. Our crude oil and natural gas assets are strategic resources that can, and should, be deployed in the service of the transition and, indeed, of the framework for the planet's health and wellbeing represented by the United Nations Sustainable Development Goals (SDGs).

To support our strategy, we regularly communicate with our stakeholders, including via our sustainability reporting. In 2018, reflecting our review of TCFD recommendations, we updated our engagement to include a broader inclusion of sustainability in regulatory reporting.

For more information, please see references to sustainability throughout this document, including the Climate Risk discussion. For additional context, our Sustainability Report is available online at www.vermilionenergy.com (under the heading “Our Responsibility”).

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

Accomplishments

- Vermilion was named to the CDP Climate Leadership Level (A-) for the second consecutive year in 2018. We were the only Canadian oil and gas company and one of only two North American oil and gas companies to receive this designation, ranking Vermilion in the top 5% of oil and gas companies globally.
- The Company received a top quartile ranking for our industry sector in RobecoSAM's annual Corporate Sustainability Assessment ("CSA"). The CSA analyzes sustainability performance across economic, environmental, governance and social criteria, and is the basis of the Dow Jones Sustainability Indices.
- Vermilion was ranked top of our peer group in the Sustainalytics ESG (environment, social, governance) rankings.
- Vermilion's MSCI ESG rating continued at A for 2018, marking the second consecutive year Vermilion has scored at this level, and our Governance Metrics score ranked in the top decile globally.
- We received ISS QualityScore decile ratings of 1 for Environmental and 2 for Social, which assess corporate disclosure and transparency practices in these areas, where 1 indicates lowest risk.
- Vermilion has earned recognition on the Corporate Knights' Future 40 Responsible Corporate Leaders in Canada listing every year since the list's inception in 2014. In 2018, we ranked 11th, and were the highest rated oil and gas company on the list.
- In February 2018, Vermilion received the Finance and Sustainability Initiative's ("FSI") award for Best Sustainability Report in the Non-Renewable Resources - Oil and Gas category. In 2019, we were a finalist for the same award. Based in Montreal, the FSI is a non-profit organization dedicated to promoting sustainable finance and, more specifically, responsible investment to financial institutions, companies, and universities. Sustainability reports were graded on a number of criteria, including transparency and balance, reliability and completeness, and the use of ESG materiality.

Climate-related Disclosures

Vermilion has publicly released our identified climate risks and opportunities since our first annual CDP Climate Response in 2014. In alignment with recommendations from the Task Force on Climate-related Financial Disclosures, under the TCFD’s Strategy category, we are also including them in this document. For more information on our sustainability-related governance, strategy, risk management, and metrics and targets, including those related to climate, please see our 2019 Proxy Statement and Information Circular, and our online sustainability reporting, particularly the Performance Metrics section and our 2018 CDP Response.

Risk / Opportunity	Description of Impacts[1,2] - Risk Category - Risk Timeframe	Potential Financial Impact	Management Context
Increased Pricing of GHG Emissions e.g. Carbon Tax	- Policy and Legal - Short-term Vermilion's operations were subject to carbon taxation in Alberta, Canada starting in January 2017 and potentially in Saskatchewan as a result of a Canada-wide carbon tax in 2019, affecting the cost of operating in our Canada Business Unit.	The current financial impact of taxation currently does not exceed $0.5MM per annum. We anticipate this to increase in the medium-term.	The potential financial impact is based on proposed changes to carbon pricing in our operating regions out to 2023, resulting in expansion of emission sources covered. This estimate is based on the probable cost scenario identified in our Carbon Liability Assessment Tool.
Enhanced Emissions	- Policy and Legal - Short-term	Based on our current output in Alberta, France and the	Regulations in all of our business units are monitored on an

Reporting Obligations	Emissions reporting obligations are an ongoing risk and have the can change due to political and regulatory evolution. The impact to Vermilion would be a decreased netback on a per BOE basis, due to increased expenditures for personnel time and system development and implementation, to allow for more robust emissions quantification.	Netherlands, current regulated thresholds, and growth, we anticipate that cost associated with meeting emission reporting obligations will increase in the short-term, likely as a small increase in operational costs.	ongoing basis, and assumptions/ scenario planning is used annually to assess risk. Vermilion also engages stakeholders relating to emissions reporting obligations. Management of this risk is built into Vermilion's operations and our Enterprise Risk Matrix.
Mandates on and Regulation of Existing Products and Services	- Policy and Legal; Technology - Short-term Vermilion's operations are subject to regional regulatory changes that result in changes to equipment requirements such as engineering and equipment modifications to reduce carbon emissions and / or emissions of criteria air contaminants.	In Canada, operational modifications required to comply with Directive 039 are estimated to have cost $1MM by the end of implementation in 2018. The costs associated with the Netherlands MJA3 program are built into our operating costs and no significant expenditures are anticipated in the near term.	Vermilion's participation in the MJA3 program in the Netherlands since 2005, for example, has resulted in projects that have reduced our operations energy intensity by 76%. Such regulatory changes continue to lead Vermilion to complete engineering reviews and facility updates resulting in emission reductions beyond regulatory requirements.

Risk / Opportunity	Description of Impacts[1,2] - Risk Category - Risk Timeframe	Potential Financial Impact	Management Context
Changes in Emissions Regulations	- Policy and Legal - Medium-term The risk associated with a change in emission regulations in one or more of our business units is accounted for by Vermilion's Enterprise Risk Matrix, with mitigation measures are reviewed, updated and implemented on an annual basis. A shift in international regulations may also result in an impact to Vermilion's supply chain, resulting in a limitation of market access or direct impact to the price of our products. As Vermilion maintains a diversified asset base, we believe the risk to the marketability of our products is low.	Following the COP21 conference, the importance of sustainable development and reduction of emission levels was confirmed by the commitments made by national governments. Based on the anticipated changes in the various regulatory regimes under which Vermilion operates, the financial impact due to a regulatory change over the next 3 years is anticipated to be less than $2.5MM. This does not include the cost associated with emission reduction projects completed on an annual basis, or previous projects that have annual emissions reductions.	The formalization of Integrated Sustainability as a strategic objective in Vermilion's long-term strategic plan allows us to better understand, identify, proactively respond and manage the potential risk and uncertainty inherent in an evolving sustainability framework, both at a regional and corporate level. As an example, beginning in 2017, Vermilion added requirements to assess capital expenditures for potential sustainability-related impacts.
Changes in Temperature Extremes	- Physical - Long-term A decrease in temperature extremes experienced in the winter months (i.e. lower seasonal lows) could increase the amount of fuel gas used by a variety of equipment essential for safe production. Additional equipment could also be required (e.g. building heaters, line heaters) to ensure safe and efficient operation, thus increasing our carbon footprint and costs. Temperature extremes could also increase capital costs associated with drilling, completion and workover operations due to increased timelines, decreased productivity, equipment breakdown, etc. For example, warmer winters would have a direct impact on Vermilion's more northern operations, through a decreased ability to access lands and increased construction capital requirements.	The financial implications on an annual basis are difficult to quantify; however, based on Vermilion's experience, the most significant financial implications would result from shutdowns in drilling or completions locations. The estimated cost of this would be $0.5MM per day of delay.	As extreme weather cannot be controlled, Vermilion uses our various Management Systems and processes to protect the health and safety of our workers, contractors and the public, and to protect the environment from adverse effect. As an example of how we have reduced the potential impact related to access in remote assets, we use multi-well pads wherever possible, with multiple horizontal wells drilled from a single location. This reduces the aerial impact of these activities on the environment, habitat fragmentation and carbon emissions associated with lease construction and equipment mobilization/demobilization. Using multi-well locations would significantly decrease capital considerations in the event that limited frost days were realized in the coming years.
Changes In Precipitation Patterns and Extreme Variability	- Physical - Long-term Vermilion holds assets inland, in coastal regions, and offshore. A	The financial implications of a single time event (e.g. wildfire) and continued strain event (e.g. drought) have been assessed on	As these incidents are beyond Vermilion's control, we take measures to ensure effective emergency response to extreme

in Weather Patterns	change in precipitation in any of these locations could have a negative impact on operations due to drought or flooding. Flooding could result in limited access to locations / facilities, and poses a risk to our corporate headquarters. Alternatively, drought conditions could impact the availability of surface and / or groundwater, which Vermilion, in part, relies on for drilling and completion activities. This could negatively impact forecasted growth by increasing the timelines and capital costs to bring new infrastructure onto production.	a case-specific basis, and the financial implications of these events is believed to be manageable (impact under $10MM). Vermilion maintains insurance to mitigate the potential impact of precipitation extreme events (e.g. flooding). Insurance for locations that have been identified as potentially being impacted by drought-induced events (e.g. wildfire) is estimated at $0.45MM per annum.	weather events, to protect the health and safety of our workers, contractors and the public, to protect the environment, and to limit the financial impact of the event. In the case of a longer term extreme precipitation event or drought, Vermilion has implemented water management programs to reduce our reliance on fresh water sources.
Rising Sea Levels	- Physical - Long-term Vermilion owns and operates assets in the Netherlands. We have identified and assessed the potential risk associated with rising sea levels here, as it has the potential to physically impact our operations due to issues such as flooding, transportation difficulties and supply chain interruptions. Rising sea levels also pose a threat related to the salinization of groundwater.	Vermilion reviews the potential impact of rising sea levels annually as part of our Corporate Risk Matrix. We estimate the potential total financial implication to be $153MM, before mitigation measures, in our Netherland operations.	There is no measure available to protect Vermilion's Netherlands assets in the event that water levels rise to a level that would impact facilities below sea level. Salinization of the groundwater regime would impact the entire region; similarly, no measures are currently available to protect against this. Based on Vermilion's assessment of the probability of these events occurring over the next 5 years being less than 0.5%, we have accepted this level of risk exposure.
Increased Severity of Extreme Weather Events such as Cyclones and Floods	- Physical - Medium-term Vermilion owns and operates an offshore platform in the Wandoo field off northwestern Australia, and co-owns and operates the Corrib project off the Irish coast. Extreme weather events such as cyclones have the potential to directly impact our offshore operations resulting in down time or damage to infrastructure, and can impact the downstream handling capacity of our partners, resulting in a limitation to the distribution and sale of our products.	Based on the value of the Wandoo Platform and a 1-in-2000 year cyclonic event, the financial implications associated with damage due to a severe weather event is estimated at $179MM (total impact before insurance). The third-party costs associated with potential damages from extreme weather events are not tracked by Vermilion.	Vermilion maintains insurance as a mitigative measure to reduce the financial impact associated with damage to our assets due to severe weather events. We also have protocols for monitoring and preparing for cyclones, and have invested in our emergency response capabilities in the event of damage to our assets as a result of a cyclone or severe weather event. Operational changes are made as required to ensure (in order of priority) worker health and safety, protection of the environment, and protection of Vermilion’s assets.

Risk / Opportunity	Description of Impacts[1,2] - Risk Category - Risk Timeframe	Potential Financial Impact	Management Context
Changing Customer Behaviour	- Market; Reputational - Long-term As consumers and governments become more socially aware of the sources of their energy, negative perceptions of organizations or production methods have the potential to impact energy sector companies through company valuations, restricted licensing and permitting, and stakeholder opposition.	The impact of decreased consumer confidence and perception is not calculable. On a per share basis, the market impact of the loss of $1 per share would be approximately $152MM. The direct cost of Vermilion's operating excellence and risk management cannot be quantified on a single risk basis.	Vermilion is positioned within the evolving energy transition, with an unwavering commitment to our priorities of health and safety, environmental protection, and economic prosperity. We believe that those commitments, and our contributions to the UN SDGs constitute qualitative advantages that set us apart from our competitors. Sustainable practices are ingrained into the way we operate, and we will continue to focus on our Integrated Sustainability strategic objective. We believe this advantage attracts investors to Vermilion and will continue to give Vermilion a competitive advantage in the future.
Opportunity: Participation in Carbon Market	- Financial - Medium term The European Union Emissions Trading Scheme (ETS) allows for the generation and movement of certified carbon credits from emissions-saving projects around the world. With the revisions pending in Phase 4, it is anticipated that there will be an active market and consumers for the offset credits generated at some of our sustainability initiatives around the world, likely providing opportunities for Vermilion to generate certified energy reduction and offset credits.	Vermilion is not accounting for any short term financial impact. It is estimated that following the change to the EU ETS in Phase 4, the carbon price will stabilize at between approximately €15 and €30 per tCO_2e. The financial impact to Vermilion annually is estimated to be up to $1MM.	We are currently evaluating the benefit that certified offset credits from various emission reduction projects across our operations could provide. Examples of projects with this potential include our Tomato Greenhouse Cogeneration project in France, our partnerships for geothermal applications in residential neighborhoods in France, and our developing geothermal projects in the Netherlands. Vermilion's project assessment framework is applied to each identified opportunity, including considerations associated with emissions offset.
Opportunity: Development of New Products and Services through R&D and Innovation	- Products - Short-term As Vermilion has developed our emissions quantification programs across the globe, we have developed more robust methods for sharing of technologies and techniques from across our operations, both internally and externally. Our increased focus on tracking emissions has supported the assessment of opportunities	As this opportunity is in the early stage of assessment, it is difficult to quantify the financial impact, but it is estimated at up to $2MM per year. Potential also exists for significant cost adjustments, as assets slated for abandonment could be repurposed to generate geothermal energy.	We have technical experts who provide input into potential geothermal projects as they are identified. These teams are supported by corporate sustainability staff in connecting internal and external stakeholders. These teams have responsibilities specific to geothermal opportunities as these projects move through their preliminary stages. To further support identification of

	across business units and sharing of technical expertise.		opportunities, and engagement with stakeholders, Vermilion has appointed sustainability leads in all our business units.
Opportunity: Shift in Consumer Preferences	- Products, Reputational - Long-term Under the Canadian Environmental Protection Act and based on commitments made by the Canadian and Alberta governments relating to COP21, there is a commitment to reduce emissions for coal-fired power generation. Based on this and with a number of power generating facilities in Alberta nearing the end of their service life, the demand for natural gas is likely to increase due to increased use of combined cycle gas turbine (CCGT) power generation. Alberta has also committed to significantly reducing its demand for coal for power generation by 2050.	The short term impact on gas pricing is anticipated to be low, increasing to medium in the mid to long term. Once the regulations are implemented, there is a potential for an increase in the demand and pricing for natural gas, from which Vermilion would benefit. Based on current estimates, an increase in gas price of $1 per mcf would result in a positive impact to sales of approximately $35MM.	As we move further into the energy transition, we foresee natural gas playing an impactful role as a less carbon intense fuel than other options (i.e. coal). Vermilion continues to focus on the identification of resources and assets where we have the opportunity to apply our industry leading expertise to optimize production while reducing emissions. An example of our strategy to realize this opportunity is our asset base in Alberta, which currently includes a large liquids rich gas play. Vermilion's marketing team is also actively pursuing options for our natural gas production that will enable Vermilion to achieve the best netbacks on production.
Opportunity: Ability to Diversify Business Activities	- Products - Long-term Vermilion maintains a diverse, stable global portfolio of oil and gas assets. Our strong record of safe and socially conscious development of energy resources has provided opportunities to access and develop these resources. We see our commitment to sustainability as core to our business, which has provided important organizational focus on emissions quantification and management. As consumers become more aware of and involved in the selection of their energy sources and associated carbon intensity, we believe that Vermilion will continue to be a top quartile choice, providing us with opportunities not available to peer organizations.	The financial impact of changing consumer preferences is difficult to quantify. We foresee opportunities in two distinct areas: first, in consumers selecting premium energy products (top quartile, low carbon intensity), with these products demanding a higher price than other energy sources on the market. Currently we estimate the potential impact of premium pricing in the long term to be $1-5 per boe (24.8MM based on $1 per boe). The second opportunity, which we are already receiving benefit from, is access to more stringent markets, supported by our environmental and sustainability performance, such as our entry into German, Hungarian and Croatian oil and gas operations in the last several years.	Vermilion made the organizational change to established Integrated Sustainability as one of our strategic objectives in 2015. This provided important organizational focus on matters such as environmental performance, including climate change. Our strategy is to continue to support Integrated Sustainability, with personnel who are experts in their field, as well as financially supporting programs and projects that reduce emissions while optimizing production. An example of this is the addition of personnel who have specific responsibilities associated with sustainability in our business units, including study and feasibility assessment of green energy generation.
Opportunity: Shift Toward Decentralized Energy Generation	- Products, Reputational - Long-term The carbon intensity of energy used around the world has a direct relationship to where the energy product was generated. Vermilion's business unit structure supports production and distribution of energy products into local markets. This	On an operating netback (sales) basis, based on current estimates, the financial premium of our non-Canadian assets was $340.8MM. The potential future advantage is anticipated to increase as we expand production in markets outside North America and provide sources of energy to local	Vermilion continues to assess where we can access local markets for our production, while exploring regions to expand our operations. The actions taken in the past several years to realize this opportunity include alterations to our structure, our strategic objectives and our operational development plans to

	strategy results in the significant reduction of the carbon footprint of our energy when compared to non-local sources.	markets. The costs associated with adjustment of our organizational structure are built into our costs across the company.	support Vermilion as a distributed energy provider, and exploration and development programs in regions with relatively low energy production as compared to consumption (i.e. Hungary).

Note 1: Short term (0 to 3 years); Medium term (3 to 6 years); Long term (6 to 50 years)

Note 2: Risk summary is based on our fiscal year 2017 environmental reporting through CDP. Fiscal year 2018 environmental reporting will be available in mid-2019.

Corporate Governance

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

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

As a Canadian reporting issuer with securities listed on the TSX and the New York Stock Exchange (“NYSE”), Vermilion Energy Inc. (“Vermilion”) is required to comply with all applicable Canadian requirements adopted by the Canadian Securities Administrators and the TSX, and applicable rules for foreign private issuers adopted by the U.S. Securities and Exchange Commission that give effect to the provisions of the *Sarbanes-Oxley Act of 2002*.

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

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

Disclosure Controls and Procedures

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

As of December 31, 2018, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded and certified that our disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

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

The Chief Executive Officer and the Chief Financial Officer of Vermilion have assessed the effectiveness of Vermilion’s internal control over financial reporting as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers’ Annual and Interim Filings. The assessment was based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Chief Executive Officer and the Chief Financial Officer of Vermilion have concluded that Vermilion’s internal control over financial reporting was effective as of December 31, 2018. The effectiveness of Vermilion’s internal control over financial reporting as of December 31, 2018 has been audited by Deloitte LLP, as reflected in their report included in the 2018 audited annual financial statements filed with the US Securities and Exchange Commission. No changes were made to Vermilion’s internal control over financial reporting during the year ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

Vermilion has limited the scope of design controls and procedures ("DC&P") and internal controls over financial reporting to exclude the controls, policies, and procedures of Spartan Energy Corp (which was acquired in May of 2018) and Shell E&P Ireland Limited (which was acquired in December of 2018). The scope limitation is in accordance with section 3.3(1)(b) of NI 52-109 which allows an issuer to limit the design of DC&P and ICFR to exclude controls, policies, and procedures of a business that the issuer acquired not more than 365 days before the end of the fiscal period.

The table below presents the summary financial information of Spartan and Shell E&P Ireland Limited included in Vermilion's financial statements as at and for the year ended December 31, 2018:

($MM)	As at December 31, 2018
Non-current assets	1,556
Non-current liabilities	69
Net assets	1,422

($MM)	Year ended December 31, 2018
Revenue	243
Net earnings	45

Supplemental Table 1: Netbacks

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

	Q4 2018			2018			Q4 2017	2017
	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Liquids $/bbl	Natural Gas $/mcf	Total $/boe	Total $/boe	Total $/boe
Canada								
Sales	48.70	1.73	**33.30**	60.57	1.54	**37.81**	31.21	30.72
Royalties	(7.29)	(0.09)	**(4.57)**	(8.67)	0.02	**(4.77)**	(3.07)	(3.09)
Transportation	(2.62)	(0.17)	**(1.99)**	(2.26)	(0.16)	**(1.69)**	(1.60)	(1.61)
Operating	(13.09)	(1.35)	**(11.09)**	(11.68)	(1.32)	**(10.00)**	(7.38)	(7.47)
Operating netback	25.70	0.12	**15.65**	37.96	0.08	**21.35**	19.16	18.55
General and administration			**(0.38)**			**(0.34)**	(0.84)	(0.89)
Fund flows from operations netback			**15.27**			**21.01**	18.32	17.66
France								
Sales	84.94	1.74	**84.02**	89.68	1.74	**89.44**	75.13	67.08
Royalties	(11.86)	(0.03)	**(11.72)**	(11.64)	(0.04)	**(11.60)**	(10.11)	(7.15)
Transportation	(3.21)	—	**(3.17)**	(2.59)	—	**(2.59)**	(4.27)	(3.66)
Operating	(13.88)	—	**(13.71)**	(13.61)	—	**(13.56)**	(13.67)	(12.76)
Operating netback	55.99	1.71	**55.42**	61.84	1.70	**61.69**	47.08	43.51
General and administration			**(3.71)**			**(3.51)**	(4.06)	(3.40)
Current income taxes			**(0.86)**			**(3.74)**	(2.24)	(2.64)
Fund flows from operations netback			**50.85**			**54.44**	40.78	37.47
Netherlands								
Sales	69.95	10.95	**65.77**	74.85	9.71	**58.44**	47.41	43.24
Royalties	—	(0.11)	**(0.67)**	—	(0.19)	**(1.12)**	(0.75)	(0.69)
Operating	—	(1.42)	**(8.40)**	—	(1.58)	**(9.40)**	(8.09)	(8.49)
Operating netback	69.95	9.42	**56.70**	74.85	7.94	**47.92**	38.57	34.06
General and administration			**(0.88)**			**(0.69)**	(0.63)	(0.89)
Current income taxes			**(9.31)**			**(5.83)**	8.08	1.33
Fund flows from operations netback			**46.51**			**41.40**	46.02	34.50
Germany								
Sales	75.53	9.72	**62.74**	84.14	8.70	**61.47**	50.22	44.37
Royalties	(3.32)	(0.57)	**(3.41)**	(2.55)	(0.99)	**(4.94)**	(4.78)	(4.30)
Transportation	(9.14)	(0.41)	**(4.16)**	(9.53)	(0.48)	**(4.79)**	(3.09)	(4.01)
Operating	(24.48)	(2.84)	**(18.95)**	(22.53)	(2.50)	**(17.18)**	(16.01)	(13.03)
Operating netback	38.59	5.90	**36.22**	49.53	4.73	**34.56**	26.34	23.03
General and administration			**(6.61)**			**(5.52)**	(5.53)	(5.02)
Fund flows from operations netback			**29.61**			**29.04**	20.81	18.01
Ireland								
Sales	—	11.15	**66.91**	—	10.19	**61.12**	50.79	43.14
Transportation	—	(0.23)	**(1.40)**	—	(0.25)	**(1.53)**	(1.74)	(1.46)
Operating	—	(0.94)	**(5.64)**	—	(0.76)	**(4.58)**	(3.45)	(4.95)
Operating netback	—	9.98	**59.87**	—	9.18	**55.01**	45.60	36.73
General and administration			**(2.55)**			**(2.50)**	(0.60)	(0.65)
Fund flows from operations netback			**57.32**			**52.51**	45.00	36.08

	Q4 2018 Liquids $/bbl	Q4 2018 Natural Gas $/mcf	Q4 2018 Total $/boe	2018 Liquids $/bbl	2018 Natural Gas $/mcf	2018 Total $/boe	Q4 2017 Total $/boe	2017 Total $/boe
Australia								
Sales	97.19	—	**97.19**	95.11	—	**95.11**	83.32	73.99
Operating	(38.92)	—	**(38.92)**	(33.57)	—	**(33.57)**	(28.11)	(24.03)
PRRT [1]	5.98	—	**5.98**	(3.04)	—	**(3.04)**	(8.25)	(9.50)
Operating netback	64.25	—	**64.25**	58.50	—	**58.50**	46.96	40.46
General and administration			**(3.44)**			**(3.10)**	(7.37)	(3.93)
Corporate income taxes			**(0.53)**			**(4.16)**	(4.05)	(2.17)
Fund flows from operations netback			**60.28**			**51.24**	35.54	34.36
United States								
Sales	53.92	3.29	**44.85**	64.06	2.67	**52.90**	62.40	53.84
Royalties	(14.96)	(0.90)	**(12.43)**	(16.71)	(0.73)	**(13.85)**	(17.16)	(14.99)
Transportation	—	—	**—**	—	—	**—**	(0.21)	(0.14)
Operating	(8.68)	(1.48)	**(8.73)**	(8.97)	(1.39)	**(8.83)**	(5.70)	(5.95)
Operating netback	30.28	0.91	**23.69**	38.38	0.55	**30.22**	39.33	32.76
General and administration			**(4.28)**			**(8.67)**	(18.28)	(15.22)
Fund flows from operations netback			**19.41**			**21.55**	21.05	17.54
Total Company								
Sales	60.48	5.83	**48.90**	71.70	5.45	**52.95**	47.49	44.41
Realized hedging (loss) gain	(1.84)	(0.74)	**(3.03)**	(3.72)	(0.55)	**(3.51)**	(1.12)	0.19
Royalties	(7.89)	(0.14)	**(4.70)**	(8.67)	(0.10)	**(4.80)**	(3.52)	(3.01)
Transportation	(2.52)	(0.16)	**(1.81)**	(2.22)	(0.17)	**(1.64)**	(1.79)	(1.76)
Operating	(15.26)	(1.36)	**(12.04)**	(14.40)	(1.31)	**(11.26)**	(9.76)	(9.79)
PRRT [1]	0.47	—	**0.26**	(0.29)	—	**(0.15)**	(0.53)	(0.80)
Operating netback	33.44	3.43	**27.58**	42.40	3.32	**31.59**	30.77	29.24
General and administration			**(1.37)**			**(1.64)**	(2.39)	(2.20)
Interest expense			**(2.23)**			**(2.30)**	(2.05)	(2.32)
Realized foreign exchange loss			**0.63**			**0.01**	0.43	0.09
Other income			**0.03**			**0.03**	0.02	0.03
Corporate income taxes			**(0.85)**			**(1.22)**	0.35	(0.50)
Fund flows from operations netback			**23.79**			**26.47**	27.13	24.34

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

Supplemental Table 2: Hedges

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

The following tables outline Vermilion's outstanding risk management positions as at December 31, 2018:

Crude Oil	Period	Exercise date [1]	Currency	Bought Put Volume (bbl/d)	Weighted Average Bought Put Price / bbl	Sold Call Volume (bbl/d)	Weighted Average Sold Call Price / bbl	Sold Put Volume (bbl/d)	Weighted Average Sold Put Price / bbl	Swap Volume (bbl/d)	Weighted Average Swap Price / bbl
Dated Brent											
3-Way Collar	Sep 2018 - Jun 2019		CAD	2,500	91.20	2,500	98.63	2,500	76.00	—	—
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,350	91.76
3-Way Collar	Aug 2018 - Jun 2019		USD	500	66.92	500	80.00	500	55.00	—	—
3-Way Collar	Jan 2019 - Dec 2019		USD	500	70.00	500	80.00	500	60.00	—	—
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	—	750	61.33
Swap	Jul 2018 - Jun 2019		USD	—	—	—	—	—	—	1,500	68.52
Swap	Jan 2019 - Dec 2019		USD	—	—	—	—	—	—	2,250	73.17
WTI											
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,050	81.41
3-Way Collar	Jan 2019 - Dec 2019		USD	250	70.00	250	80.25	250	60.00	—	—
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	—	250	54.00

North American Gas	Period	Exercise date [1]	Currency	Bought Put Volume (mcf/d)	Weighted Average Bought Put Price / mcf	Sold Call Volume (mcf/d)	Weighted Average Sold Call Price / mcf	Sold Put Volume (mcf/d)	Weighted Average Sold Put Price /mcf	Swap Volume (mcf/d)	Weighted Average Swap Price / mcf
AECO											
Swap	Dec 2018 - Mar 2019		CAD	—	—	—	—	—	—	2,500	2.41

AECO Basis (AECO less NYMEX Henry Hub)										
Swap	Jan 2019 - Jun 2020	USD	—	—	—	—	—	—	2,500	(0.93)
AECO Basis (AECO less Chicago NGI)										
Swap	Nov 2018 - Mar 2019	USD	—	—	—	—	—	—	5,000	(1.46)
NYMEX Henry Hub										
Swap	Jan 2019 - Mar 2019	USD	—	—	—	—	—	—	5,000	4.00
Chicago NGI										
Swap	Dec 2018 - Mar 2019	USD	—	—	—	—	—	—	5,000	4.40
SOCAL Border										
Swap (2)	Jan 2019	USD	—	—	—	—	—	—	10,000	5.50
Swap (2)	Feb 2019	USD	—	—	—	—	—	—	10,000	4.39
Swap (2)	Mar 2019	USD	—	—	—	—	—	—	10,000	3.36

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract with Vermilion at the above detailed terms.
(2) These swaps hedge a physical sales agreement to sell Alberta natural gas production at SOCAL Border pricing less a fixed differential.

European Gas	Period	Exercise date [1]	Currency	Bought Put Volume (mcf/d)	Weighted Average Bought Put Price / mcf	Sold Call Volume (mcf/d)	Weighted Average Sold Call Price / mcf	Sold Put Volume (mcf/d)	Weighted Average Sold Put Price /mcf	Swap Volume (mcf/d)	Weighted Average Swap Price / mcf
NBP											
3-Way Collar	Jan 2019 - Dec 2019		EUR	17,197	4.97	17,197	5.65	17,197	3.79	—	—
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	3.74	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	19,654	5.10	19,654	5.92	19,654	4.01	—	—
Collar	Oct 2018 - Mar 2019		EUR	3,685	6.40	2,457	7.62	—	—	—	—
Call	Oct 2018 - Mar 2019		EUR	—	—	12,327	6.28	—	—	—	—
Swap	Oct 2018 - Mar 2019		EUR	—	—	—	—	—	—	4,913	7.92
Swaption	Jul 2019 - Jun 2021	June 28, 2019	EUR	—	—	—	—	—	—	9,827	5.64
Swaption	Oct 2019 - Mar 2020	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
Swaption	Oct 2020 - Mar 2021	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
Swaption	Oct 2021 - Mar 2022	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
NBP Basis (NBP less NYMEX HH)											
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	—	—	—
TTF											
3-Way Collar	Oct 2017 - Dec 2019		EUR	7,370	4.59	7,370	5.42	7,370	2.93	—	—

3-Way Collar	Jan 2018 - Dec 2019	EUR	3,685	4.74	3,685	5.52	3,685	3.13	—	—
3-Way Collar	Jan 2019 - Dec 2019	EUR	12,284	5.05	12,284	5.72	12,284	3.69	—	—
3-Way Collar	Jan 2020 - Dec 2020	EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—
Swap	Oct 2017 - Dec 2019	EUR	—	—	—	—	—	—	7,370	4.87
Swap	Jan 2018 - Dec 2019	EUR	—	—	—	—	—	—	1,228	5.00
Swap	Jul 2018 - Dec 2019	EUR	—	—	—	—	—	—	4,913	4.98
Swap	Jan 2019 - Dec 2019	EUR	—	—	—	—	—	—	2,457	4.92

Cross Currency Interest Rate		Receive Notional Amount (USD)	Rate (LIBOR +)	Pay Notional Amount (CAD)	Rate (CDOR +)
Swap	Jan 2019	1,018,563,000	1.70%	1,354,900,000	1.02%

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

Supplemental Table 3: Capital Expenditures and Acquisitions

By classification ($M)	Q4 2018	Q3 2018	Q4 2017	2018	2017
Drilling and development	**160,359**	142,116	61,911	**503,842**	290,593
Exploration and evaluation	**3,221**	4,069	12,392	**14,372**	29,856
Capital expenditures	**163,580**	146,185	74,303	**518,214**	320,449
Acquisitions	**(31,314)**	193,677	3,048	**276,308**	27,637
Shares issued for acquisition	**—**	—	—	**1,235,221**	—
Contingent consideration	**2**	—	—	**2**	—
Long-term debt net of working capital assumed	**34,005**	4,496	—	**247,898**	—
Acquisitions	**2,689**	198,173	3,048	**1,759,425**	27,637

By category ($M)	Q4 2018	Q3 2018	Q4 2017	2018	2017
Drilling, completion, new well equip and tie-in, workovers and recompletions	**151,511**	118,317	45,533	**434,875**	225,668
Production equipment and facilities	**9,166**	26,964	18,109	**62,496**	59,629
Seismic, studies, land and other	**2,903**	904	10,661	**20,843**	35,152
Capital expenditures	**163,580**	146,185	74,303	**518,214**	320,449
Acquisitions	**2,689**	198,173	3,048	**1,759,425**	27,637
Total capital expenditures and acquisitions	**166,269**	344,358	77,351	**2,277,639**	348,086

Capital expenditures by country ($M)	Q4 2018	Q3 2018	Q4 2017	2018	2017
Canada	**90,211**	89,837	26,865	**277,857**	148,667
France	**17,008**	15,779	20,027	**79,758**	73,381
Netherlands	**2,454**	5,056	12,300	**17,483**	31,575
Germany	**4,580**	6,497	5,279	**15,806**	9,531
Ireland	**140**	(50)	327	**224**	551
Australia	**43,760**	16,061	7,192	**75,638**	29,942
United States	**2,881**	11,386	1,018	**40,837**	19,074
Corporate	**2,546**	1,619	1,295	**10,611**	7,728
Total capital expenditures	**163,580**	146,185	74,303	**518,214**	320,449

Acquisitions by country ($M)	Q4 2018	Q3 2018	Q4 2017	2018	2017
Canada	**12,233**	6,146	788	**1,573,964**	22,011
Netherlands	**(7,860)**	2,874	(38)	**(2,087)**	(24)
Germany	**706**	959	—	**1,665**	—
Ireland	**(5,572)**	—	—	**(5,572)**	—
United States	**3,674**	187,987	91	**191,740**	3,403
Corporate	**(492)**	207	2,207	**(285)**	2,247
Total acquisitions	**2,689**	198,173	3,048	**1,759,425**	27,637

In 2018, included in cash expenditures on acquisitions of $276.3 million is: $257.8 million net paid to vendors in relation to business combinations ($339.9 million paid net of $82.1 million cash acquired); $9.9 million in asset improvements incurred subsequent to acquisitions for compliance with safety, environmental, and Vermilion's operating standards; $7.0 million paid to acquire land; and $1.6 million relating to the carry component of farm-in arrangements.

Supplemental Table 4: Production

	Q4/18	Q3/18	Q2/18	Q1/18	Q4/17	Q3/17	Q2/17	Q1/17	Q4/16	Q3/16	Q2/16	Q1/16
Canada												
Crude oil & condensate (bbls/d)	**29,557**	28,477	17,009	9,272	9,703	9,288	9,205	7,987	7,945	8,984	9,453	10,317
NGLs (bbls/d)	**6,816**	6,126	5,589	5,106	5,235	4,891	3,745	2,670	2,444	2,448	2,687	2,633
Natural gas (mmcf/d)	**146.65**	136.77	127.32	106.21	107.91	103.92	93.68	85.74	75.12	77.62	87.44	97.16
Total (boe/d)	**60,814**	57,397	43,817	32,078	32,923	31,499	28,563	24,947	22,910	24,368	26,713	29,141
% of consolidated	**60%**	59%	55%	46%	45%	46%	43%	38%	38%	37%	42%	44%
France												
Crude oil (bbls/d)	**11,317**	11,407	11,683	11,037	11,215	10,918	11,368	10,834	11,220	11,827	12,326	12,220
Natural gas (mmcf/d)	**0.82**	—	—	—	—	—	—	0.01	0.38	0.42	0.54	0.44
Total (boe/d)	**11,454**	11,407	11,683	11,037	11,215	10,918	11,368	10,836	11,283	11,897	12,416	12,293
% of consolidated	**11%**	12%	14%	16%	15%	16%	17%	17%	19%	19%	19%	19%
Netherlands												
Condensate (bbls/d)	**112**	84	87	77	105	74	104	76	57	86	96	114
Natural gas (mmcf/d)	**51.82**	44.37	43.49	44.79	55.66	34.90	31.58	39.92	41.15	47.62	49.18	53.40
Total (boe/d)	**8,749**	7,479	7,335	7,541	9,381	5,890	5,368	6,729	6,915	8,023	8,293	9,015
% of consolidated	**9%**	8%	9%	11%	13%	9%	8%	10%	11%	13%	13%	14%
Germany												
Crude oil (bbls/d)	**913**	1,019	1,008	1,078	1,148	1,054	1,047	989	—	—	—	—
Natural gas (mmcf/d)	**16.94**	14.88	14.63	16.19	18.19	20.12	19.86	19.39	14.80	14.52	14.31	15.96
Total (boe/d)	**3,736**	3,498	3,447	3,777	4,180	4,407	4,357	4,220	2,467	2,420	2,385	2,660
% of consolidated	**4%**	4%	4%	5%	6%	7%	6%	7%	4%	4%	4%	4%
Ireland												
Natural gas (mmcf/d)	**52.03**	51.38	56.56	60.87	56.23	49.04	63.81	64.82	62.92	59.28	47.26	33.90
Total (boe/d)	**8,672**	8,563	9,426	10,144	9,372	8,173	10,634	10,803	10,486	9,879	7,877	5,650
% of consolidated	**9%**	9%	12%	14%	13%	12%	16%	17%	17%	16%	12%	9%
Australia												
Crude oil (bbls/d)	**4,174**	4,704	4,132	4,971	4,993	5,473	6,054	6,581	6,388	6,562	6,083	6,180
% of consolidated	**4%**	5%	5%	7%	7%	8%	9%	10%	10%	10%	9%	9%
United States												
Crude oil (bbls/d)	**1,605**	1,461	655	574	667	880	747	365	362	383	458	368
NGLs (bbls/d)	**998**	714	62	20	43	56	76	24	23	30	26	39
Natural gas (mmcf/d)	**5.65**	4.82	0.40	0.15	0.29	0.64	0.44	0.20	0.18	0.20	0.20	0.26

Total (boe/d)	**3,545**	2,979	784	618	758	1,043	896	422	414	447	518	450
% of consolidated	**3%**	3%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%
Corporate												
Natural gas (mmcf/d)	**2.86**	1.17	—	—	—	—	—	—	—	—	—	—
Total (boe/d)	**477**	195	—	—	—	—	—	—	—	—	—	—
% of consolidated	**—**	—%	—	—	—	—	—	—	—	—	—	—
Consolidated												
Liquids (bbls/d)	**55,493**	53,991	40,225	32,134	33,109	32,634	32,346	29,526	28,439	30,320	31,129	31,871
% of consolidated	**55%**	56%	50%	46%	45%	48%	48%	46%	47%	48%	48%	49%
Natural gas (mmcf/d)	**276.77**	253.38	242.40	228.20	238.28	208.62	209.36	210.07	194.54	199.65	198.93	201.11
% of consolidated	**45%**	44%	50%	54%	55%	52%	52%	54%	53%	52%	52%	51%
Total (boe/d)	**101,621**	96,222	80,625	70,167	72,821	67,403	67,240	64,537	60,863	63,596	64,285	65,389

	2018	2017	2016	2015	2014	2013
Canada						
Crude oil & condensate (bbls/d)	**21,154**	9,051	9,171	11,357	12,491	8,387
NGLs (bbls/d)	**5,914**	4,144	2,552	2,301	1,233	1,666
Natural gas (mmcf/d)	**129.37**	97.89	84.29	71.65	55.67	42.39
Total (boe/d)	**48,630**	29,510	25,771	25,598	23,001	17,117
% of consolidated	**56%**	45%	40%	46%	47%	41%
France						
Crude oil (bbls/d)	**11,362**	11,084	11,896	12,267	11,011	10,873
Natural gas (mmcf/d)	**0.21**	—	0.44	0.97	—	3.40
Total (boe/d)	**11,396**	11,085	11,970	12,429	11,011	11,440
% of consolidated	**13%**	16%	19%	23%	22%	28%
Netherlands						
Condensate (bbls/d)	**90**	90	88	99	77	64
Natural gas (mmcf/d)	**46.13**	40.54	47.82	44.76	38.20	35.42
Total (boe/d)	**7,779**	6,847	8,058	7,559	6,443	5,967
% of consolidated	**9%**	10%	13%	14%	13%	15%
Germany						
Crude oil (bbls/d)	**1,004**	1,060	—	—	—	—
Natural gas (mmcf/d)	**15.66**	19.39	14.90	15.78	14.99	—
Total (boe/d)	**3,614**	4,291	2,483	2,630	2,498	—
% of consolidated	**4%**	6%	4%	5%	5%	—
Ireland						
Natural gas (mmcf/d)	**55.17**	58.43	50.89	0.03	—	—
Total (boe/d)	**9,195**	9,737	8,482	5	—	—
% of consolidated	**11%**	14%	13%	—	—	—
Australia						
Crude oil (bbls/d)	**4,494**	5,770	6,304	6,454	6,571	6,481
% of consolidated	**5%**	8%	10%	12%	13%	16%
United States						
Crude oil (bbls/d)	**1,078**	666	393	231	49	—
NGLs (bbls/d)	**452**	50	29	7	—	—
Natural gas (mmcf/d)	**2.78**	0.39	0.21	0.05	—	—
Total (boe/d)	**1,992**	781	457	247	49	—
% of consolidated	**2%**	1%	1%	—	—	—
Corporate						
Natural gas (mmcf/d)	**1.02**	—	—	—	—	—
Total (boe/d)	**169**	—	—	—	—	—
% of consolidated	**—**	—	—	—	—	—
Consolidated						
Liquids (bbls/d)	**45,548**	31,915	30,433	32,716	31,432	27,471
% of consolidated	**52%**	47%	48%	60%	63%	67%
Natural gas (mmcf/d)	**250.33**	216.64	198.55	133.24	108.85	81.21
% of consolidated	**48%**	53%	52%	40%	37%	33%
Total (boe/d)	**87,270**	68,021	63,526	54,922	49,573	41,005

Supplemental Table 5: Segmented Financial Results

	Three Months Ended December 31, 2018								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Drilling and development	90,211	16,870	2,292	3,087	140	43,760	2,881	1,118	160,359
Exploration and evaluation	—	138	162	1,493	—	—	—	1,428	3,221
Crude oil and condensate sales	146,947	85,758	721	6,742	—	39,351	10,452	—	289,971
NGL sales	16,010	—	—	—	—	—	2,462	—	18,472
Natural gas sales	23,351	131	52,216	15,155	53,385	—	1,711	2,547	148,496
Royalties	(25,584)	(11,976)	(537)	(1,190)	—	—	(4,053)	(534)	(43,874)
Revenue from external customers	160,724	73,913	52,400	20,707	53,385	39,351	10,572	2,013	413,065
Transportation	(11,129)	(3,242)	—	(1,452)	(1,115)	—	—	—	(16,938)
Operating	(62,064)	(14,015)	(6,765)	(6,615)	(4,497)	(15,757)	(2,848)	91	(112,470)
General and administration	(2,150)	(3,792)	(709)	(2,308)	(2,037)	(1,391)	(1,396)	969	(12,814)
PRRT	—	—	—	—	—	2,422	—	—	2,422
Corporate income taxes	—	(884)	(7,492)	—	—	(216)	—	646	(7,946)
Interest expense	—	—	—	—	—	—	—	(20,827)	(20,827)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(28,319)	(28,319)
Realized foreign exchange gain	—	—	—	—	—	—	—	5,894	5,894
Realized other income	—	—	—	—	—	—	—	275	275
Fund flows from operations	**85,381**	**51,980**	**37,434**	**10,332**	**45,736**	**24,409**	**6,328**	**(39,258)**	**222,342**

	Year Ended December 31, 2018								
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Total assets	3,060,291	918,398	277,348	284,063	709,585	263,739	407,323	349,924	6,270,671
Drilling and development	277,857	79,451	17,963	10,863	224	75,638	40,837	1,009	503,842
Exploration and evaluation	—	307	(480)	4,943	—	—	—	9,602	14,372
Crude oil and condensate sales	541,844	360,471	2,462	32,704	—	150,733	31,142	—	1,119,356
NGL sales	56,554	—	—	—	—	—	4,622	—	61,176
Natural gas sales	72,774	131	163,454	49,745	205,150	—	2,701	3,630	497,585
Royalties	(84,696)	(46,781)	(3,181)	(6,626)	—	—	(10,070)	(813)	(152,167)
Revenue from external customers	586,476	313,821	162,735	75,823	205,150	150,733	28,395	2,817	1,525,950
Transportation	(29,912)	(10,426)	—	(6,420)	(5,129)	—	—	—	(51,887)
Operating	(177,499)	(54,690)	(26,681)	(23,048)	(15,366)	(53,199)	(6,421)	(110)	(357,014)
General and administration	(6,057)	(14,170)	(1,947)	(7,401)	(8,386)	(4,918)	(6,306)	(2,744)	(51,929)
PRRT	—	—	—	—	—	(4,824)	—	—	(4,824)
Corporate income taxes	—	(15,084)	(16,561)	—	—	(6,595)	—	(513)	(38,753)
Interest expense	—	—	—	—	—	—	—	(72,759)	(72,759)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(111,258)	(111,258)
Realized foreign exchange gain	—	—	—	—	—	—	—	243	243
Realized other income	—	—	—	—	—	—	—	883	883
Fund flows from operations	**373,008**	**219,451**	**117,546**	**38,954**	**176,269**	**81,197**	**15,668**	**(183,441)**	**838,652**

Non-GAAP Financial Measures

This MD&A includes references to certain financial measures which do not have standardized meanings and may not be comparable to similar measures presented by other issuers. These financial measures include fund flows from operations, a measure of profit or loss in accordance with IFRS 8 “Operating Segments” (please see Segmented Information in the Notes to the Consolidated Financial Statements) and net debt, a measure of capital in accordance with IAS 1 “Presentation of Financial Statements” (please see Capital Disclosures in the Notes to the Consolidated Financial Statements).

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

Acquisitions: The sum of acquisitions from the Consolidated Statement of Cash Flows, Vermilion common shares issued as consideration, the estimated value of contingent consideration, the amount of acquiree's outstanding long-term debt assumed plus or net of acquired working capital deficit or surplus. We believe that including these components provides a useful measure of the economic investment associated with our acquisition activity.

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

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

Covenants: The financial covenants on our revolving credit facility contain non-GAAP measures. The definitions for these financial covenants are included in Financial Position Review.

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

Free cash flow: Represents fund flows from operations in excess of capital expenditures. We use free cash flow to determine the funding available for investing and financing activities, including payment of dividends, repayment of long-term debt, reallocation to existing business units, and deployment into new ventures. We also assess free cash flow as a percentage of fund flows from operations, which is a measure of the percentage of fund flows from operations that is retained for incremental investing and financing activities.

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

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

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

Payout: We define payout as net dividends plus drilling and development costs, exploration and evaluation costs and asset retirement obligations settled. Management uses payout and payout as a percentage of fund flows from operations (also referred to as the **sustainability ratio**) to assess the amount of cash distributed back to shareholders and re-invested in the business for maintaining production and organic growth.

Return on capital employed (ROCE): ROCE is a measure that we use to analyze our profitability and the efficiency of our capital allocation process. ROCE is calculated by dividing net earnings before interest and taxes ("EBIT") by average capital employed over the preceding twelve months. Capital employed is calculated as total assets less current liabilities while average capital employed is calculated using the current period balance sheet and the previous year-end balance sheet.

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

($M)	Q4 2018	Q3 2018	Q4 2017	2018	2017
Dividends declared	**105,310**	105,192	78,653	**388,111**	311,397
Shares issued for the Dividend Reinvestment Plan	**(5,115)**	(4,320)	(21,817)	**(49,051)**	(110,493)
Net dividends	**100,195**	100,872	56,836	**339,060**	200,904
Drilling and development	**160,359**	142,116	61,911	**503,842**	290,593
Exploration and evaluation	**3,221**	4,069	12,392	**14,372**	29,856
Asset retirement obligations settled	**6,562**	2,986	3,216	**15,765**	9,334
Payout	**270,337**	250,043	134,355	**873,039**	530,687
% of fund flows from operations	**122%**	96%	74%	**104%**	88%

('000s of shares)	Q4 2018	Q3 2018	Q4 2017
Shares outstanding	**152,704**	152,497	122,119
Potential shares issuable pursuant to the VIP	**3,469**	3,250	3,021
Diluted shares outstanding	**156,173**	155,747	125,140

The following tables reconciles the calculation of return on capital employed:

($M)	2018	2017
Net earnings	**271,650**	62,258
Taxes	**83,048**	62,224
Interest expense	**72,759**	57,313
EBIT	**427,457**	181,795
Average capital employed	**4,659,566**	3,703,991
Return on capital employed	**9%**	5%

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 6, 8]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Carin Knickel [6, 8, 12]
Golden, Colorado

Stephen P. Larke [4, 6, 12]
Calgary, Alberta

Loren M. Leiker [10]
McKinney, Texas

Timothy R. Marchant [7, 10, 11]
Calgary, Alberta

Anthony Marino
Calgary, Alberta

Robert Michaleski [4, 5]
Calgary, Alberta

William Roby [8, 9, 12]
Katy, Texas

Catherine L. Williams [3, 6]
Calgary, Alberta

1 Chairman of the Board
2 Lead Director
3 Audit Committee Chair (Independent)
4 Audit Committee Member
5 Governance and Human Resources Committee Chair (Independent)
6 Governance and Human Resources Committee Member
7 Health, Safety and Environment Committee Chair (Independent)
8 Health, Safety and Environment Committee Member
9 Independent Reserves Committee Chair (Independent)
10 Independent Reserves Committee Member
11 Sustainability Committee Chair (Independent)

OFFICERS AND KEY PERSONNEL
CANADA

Anthony Marino President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Jenson Tan
Vice President Business Development

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Kyle Preston
Director Investor Relations

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES
Scott Seatter
Managing Director - U.S. Business Unit

Timothy R. Morris
Director U.S. Business Development - U.S.
Business Unit

EUROPE
Gerard Schut
Vice President European Operations

Sylvain Nothhelfer

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Export Development Canada

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Wells Fargo Bank N.A., Canadian Branch

HSBC Bank Canada

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Canadian Western Bank

Goldman Sachs Lending Partners LLC

Barclays Bank PLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

[12] Sustainability Committee Member

Managing Director - France Business Unit

Sven Tummers
Managing Director - Netherlands Business Unit

Bill Liutkus
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake
Managing Director - Australia Business Unit

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

The Toronto Stock Exchange ("VET")
The New York Stock Exchange ("VET")

INVESTOR RELATIONS
Kyle Preston
Director Investor Relations
403-476-8431 TEL
403-476-8100 FAX
1-866-895-8101 IR TOLL FREE
investor_relations@vermilionenergy.com

Disclaimer

Certain statements included or incorporated by reference in this document may constitute forward looking statements or financial outlooks under applicable securities legislation. Such forward looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", or similar words suggesting future outcomes or statements regarding an outlook. Forward looking statements or information in this document may include, but are not limited to: capital expenditures and Vermilion's ability to fund such expenditures; Vermilion's additional debt capacity providing it with additional working capital; the flexibility of Vermilion's capital program and operations; business strategies and objectives; operational and financial performance; estimated volumes of reserves and resources; petroleum and natural gas sales; future production levels and the timing thereof, including Vermilion's 2019 guidance, and rates of average annual production growth; the effect of changes in crude oil and natural gas prices, changes in exchange rates and significant declines in production or sales volumes due to unforeseen circumstances; the effect of possible changes in critical accounting estimates; statements regarding the growth and size of Vermilion's future project inventory, and the wells expected to be drilled in 2019; exploration and development plans and the timing thereof; Vermilion's ability to reduce its debt, including its ability to redeem senior unsecured notes prior to maturity; statements regarding Vermilion's hedging program, its plans to add to its hedging positions, and the anticipated impact of Vermilion's hedging program on project economics and free cash flows; the potential financial impact of climate-related risks; acquisition and disposition plans and the timing thereof; operating and other expenses, including the payment and amount of future dividends; royalty and income tax rates and Vermilion's expectations regarding future taxes and taxability; and the timing of regulatory proceedings and approvals.

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

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

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

All crude oil and natural gas reserve and resource information contained in this document has been prepared and presented in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities and the Canadian Oil and Gas Evaluation Handbook. Reserves estimates have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for such development. The actual crude oil and natural gas reserves and future production will be greater than or less than the estimates provided in this document.

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

Financial data contained within this document are reported in Canadian dollars, unless otherwise stated.

Abbreviations

$M	thousand dollars
$MM	million dollars
AECO	the daily average benchmark price for natural gas at the AECO ‘C’ hub in Alberta
bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrel of oil equivalent, including: crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe for six mcf of natural gas)
boe/d	barrel of oil equivalent per day
GJ	gigajoules
LSB	light sour blend crude oil reference price
mbbls	thousand barrels
mcf	thousand cubic feet
mmcf/d	million cubic feet per day
NBP	the reference price paid for natural gas in the United Kingdom at the National Balancing Point Virtual Trading Point.
NGLs	natural gas liquids, which includes butane, propane, and ethane
PRRT	Petroleum Resource Rent Tax, a profit based tax levied on petroleum projects in Australia
tCO_2e	tonnes of carbon dioxide equivalent
TTF	the price for natural gas in the Netherlands, quoted in megawatt hours of natural gas, at the Title Transfer Facility Virtual Trading Point
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Management's Report to Shareholders

Management's Responsibility for Financial Statements

The accompanying consolidated financial statements of Vermilion Energy Inc. are the responsibility of management and have been approved by the Board of Directors of Vermilion Energy Inc. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes to the consolidated financial statements and are prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. Where necessary, management has made informed judgments and estimates of transactions that were not yet completed at the balance sheet date. Financial information throughout the Annual Report is consistent with the consolidated financial statements.

Management ensures the integrity of the consolidated financial statements by maintaining high-quality systems of internal control. Procedures and policies are designed to provide reasonable assurance that assets are safeguarded and transactions are properly recorded, and that the financial records are reliable for preparation of the consolidated financial statements. Deloitte LLP, Vermilion's Independent Registered Public Accounting Firm, have conducted an audit of the consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States) and have provided their report.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and internal control. The Board carries out this responsibility principally through the Audit Committee, which is appointed by the Board and is comprised entirely of independent Directors. The Committee meets periodically with management and Deloitte LLP to satisfy itself that each party is properly discharging its responsibilities and to review the consolidated financial statements, Management's Discussion and Analysis and the Report of the Independent Registered Public Accounting Firm before they are presented to the Board of Directors.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining an adequate system of internal control over financial reporting. Management under the supervision and with the participation of the principal executive officer and principle financial officer conducted an evaluation of the effectiveness of the system of internal control over financial reporting based on the criteria established in *"Internal Control - Integrated Framework (2013)"* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has assessed the effectiveness of Vermilion's internal control over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Management concluded that Vermilion's internal control over financial reporting was effective as of December 31, 2018. Management has limited the scope of design controls and procedures ("DC&P") and internal controls over financial reporting to exclude the controls, policies, and procedures of Spartan Energy Corp (which was acquired in May of 2018) and Shell E&P Ireland Limited (which was acquired in December of 2018). Total assets and revenues excluded from management's assessment of internal control over financial reporting represents 23% and 14%, respectively, of the related Consolidated Financial Statement amounts as at and for the year ended December 31, 2018.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of Vermilion's internal control over financial reporting as of December 31, 2018 has been audited by Deloitte LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2018.

("Anthony Marino")

Anthony Marino
President & Chief Executive Officer

("Lars Glemser")

Lars Glemser
Vice President & Chief Financial Officer

February 27, 2019

Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control over Financial Reporting
We have audited the internal control over financial reporting of Vermilion Energy Inc. and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2018, of the Company and our report dated February 27, 2019, expressed an unqualified opinion on those financial statements.

As described in Management's Report to Shareholders, management excluded from its assessment the internal control over financial reporting of Spartan Energy Inc. and Shell E&P Ireland Limited, which were acquired in 2018, and whose financial statements constitute 23% and 14% of total assets and revenues, respectively, of the consolidated financial statement amounts as of and for the year ended December 31, 2018. Accordingly, our audit did not include the internal control over financial reporting at Spartan Energy Inc. and Shell E&P Ireland Limited.

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte LLP

Chartered Professional Accountants

Calgary, Canada
February 27, 2019

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Vermilion Energy Inc. and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of net earnings and comprehensive income, consolidated statements of cash flows, and consolidated statements of changes in shareholders' equity for the years then ended and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
February 27, 2019

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

Consolidated Financial Statements

Consolidated Balance Sheet

thousands of Canadian dollars

	Note	December 31, 2018	December 31, 2017
Assets			
Current			
Cash and cash equivalents	19	**26,809**	46,561
Accounts receivable		**260,322**	165,760
Crude oil inventory		**27,751**	17,105
Derivative instruments	9	**95,667**	17,988
Prepaid expenses		**19,328**	14,432
Total current assets		**429,877**	261,846
Derivative instruments	9	**1,215**	2,552
Deferred taxes	11	**219,411**	80,324
Exploration and evaluation assets	7	**303,295**	292,278
Capital assets	6	**5,316,873**	3,337,965
Total assets		**6,270,671**	3,974,965
Liabilities			
Current			
Accounts payable and accrued liabilities		**449,651**	219,084
Dividends payable	13	**35,122**	26,256
Derivative instruments	9	**41,016**	78,905
Income taxes payable		**37,410**	39,061
Total current liabilities		**563,199**	363,306
Derivative instruments	9	**17,527**	12,348
Long-term debt	12	**1,796,207**	1,270,330
Lease obligations	10	**108,189**	15,807
Asset retirement obligations	8	**650,164**	517,180
Deferred taxes	11	**318,134**	253,108
Total liabilities		**3,453,420**	2,432,079
Shareholders' equity			
Shareholders' capital	13	**4,008,828**	2,650,706
Contributed surplus		**78,478**	84,354
Accumulated other comprehensive income		**118,182**	71,829
Deficit		**(1,388,237)**	(1,264,003)
Total shareholders' equity		**2,817,251**	1,542,886
Total liabilities and shareholders' equity		**6,270,671**	3,974,965

Approved by the Board

(Signed "Catherine L. Williams")

Catherine L. Williams, Director

(Signed "Anthony Marino")

Anthony Marino, Director

Consolidated Statements of Net Earnings and Comprehensive Income

thousands of Canadian dollars, except share and per share amounts

		Year Ended	
	Note	Dec 31, 2018	Dec 31, 2017
Revenue			
Petroleum and natural gas sales		**1,678,117**	1,098,838
Royalties		**(152,167)**	(74,476)
Petroleum and natural gas revenue		**1,525,950**	1,024,362
Expenses			
Operating	19	**357,014**	242,267
Transportation		**51,887**	43,448
Equity based compensation	15	**60,746**	61,579
Loss (gain) on derivative instruments	9	**1,932**	(3,659)
Interest expense		**72,759**	57,313
General and administration	19	**51,929**	54,373
Foreign exchange loss (gain)		**63,000**	(74,058)
Other income		**(82)**	(37)
Accretion	8	**31,219**	26,971
Depletion and depreciation	6, 7	**609,056**	491,683
Gain on business combinations	5	**(128,208)**	—
		1,171,252	899,880
Earnings before income taxes		**354,698**	124,482
Taxes	11		
Deferred		**39,471**	30,117
Current		**43,577**	32,107
		83,048	62,224
Net earnings		**271,650**	62,258
Other comprehensive income			
Currency translation adjustments		**46,353**	41,490
Comprehensive income		**318,003**	103,748
Net earnings per share	16		
Basic		**1.93**	0.52
Diluted		**1.91**	0.51
Weighted average shares outstanding ('000s)	16		
Basic		**140,619**	120,582
Diluted		**142,335**	122,408

Consolidated Statements of Cash Flows

thousands of Canadian dollars

	Note	Year Ended Dec 31, 2018	Dec 31, 2017
Operating			
Net earnings		**271,650**	62,258
Adjustments:			
Accretion	8	**31,219**	26,971
Depletion and depreciation	6, 7	**609,056**	491,683
Gain on business combinations	5	**(128,208)**	—
Unrealized (gain) loss on derivative instruments	9	**(109,326)**	1,062
Equity based compensation	15	**60,746**	61,579
Unrealized foreign exchange loss (gain)		**63,243**	(71,742)
Unrealized other expense		**801**	637
Deferred taxes	11	**39,471**	30,117
Asset retirement obligations settled	8	**(15,765)**	(9,334)
Changes in non-cash operating working capital	19	**(6,876)**	665
Cash flows from operating activities		**816,011**	593,896
Investing			
Drilling and development	6	**(503,842)**	(290,593)
Exploration and evaluation	7	**(14,372)**	(29,856)
Acquisitions	5	**(276,308)**	(27,637)
Changes in non-cash investing working capital	19	**55,491**	407
Cash flows used in investing activities		**(739,031)**	(347,679)
Financing			
Borrowings (repayments) on the revolving credit facility	12	**251,155**	(450,646)
Issuance of senior unsecured notes	12	**—**	391,906
Payments on lease obligations	10	**(18,884)**	(4,874)
Cash dividends	13	**(330,194)**	(200,074)
Cash flows used in financing activities		**(97,923)**	(263,688)
Foreign exchange gain on cash held in foreign currencies		**1,191**	1,257
Net change in cash and cash equivalents		**(19,752)**	(16,214)
Cash and cash equivalents, beginning of year		**46,561**	62,775
Cash and cash equivalents, end of year	19	**26,809**	46,561
Supplementary information for cash flows from operating activities			
Interest paid		**70,049**	49,721
Income taxes paid		**45,228**	29,265

Consolidated Statements of Changes in Shareholders' Equity

thousands of Canadian dollars

	Year Ended	
	Dec 31, 2018	**Dec 31, 2017**
Shareholders' capital		
Balance, beginning of year	**2,650,706**	2,452,722
Shares issued for acquisition	**1,234,676**	—
Shares issued for the Dividend Reinvestment Plan	**49,051**	110,493
Vesting of equity based awards	**54,057**	69,743
Equity based compensation	**12,565**	9,270
Share-settled dividends on vested equity based awards	**7,773**	8,478
Balance, end of year	**4,008,828**	2,650,706
Contributed surplus		
Balance, beginning of year	**84,354**	101,788
Equity based compensation	**48,181**	52,309
Vesting of equity based awards	**(54,057)**	(69,743)
Balance, end of year	**78,478**	84,354
Accumulated other comprehensive income		
Balance, beginning of year	**71,829**	30,339
Currency translation adjustments	**46,353**	41,490
Balance, end of year	**118,182**	71,829
Deficit		
Balance, beginning of year	**(1,264,003)**	(1,006,386)
Net earnings	**271,650**	62,258
Dividends declared	**(388,111)**	(311,397)
Share-settled dividends on vested equity based awards	**(7,773)**	(8,478)
Balance, end of year	**(1,388,237)**	(1,264,003)
Total shareholders' equity	**2,817,251**	1,542,886

Please refer to Note 13 (Shareholders' capital) and Note 15 (Equity based compensation) for additional information.

Description of equity reserves

Shareholders' capital

Represents the recognized amount for common shares when issued, net of equity issuance costs and deferred taxes.

Contributed surplus

Represents the recognized value of unvested equity based awards that will be settled in shares. Once vested, the value of the awards are transferred to shareholders' capital.

Accumulated other comprehensive income

Represents currency translation adjustments resulting from translating the financial statements of subsidiaries with a foreign functional currency to Canadian dollars at period-end rates. These amounts may be reclassified to net earnings if there is a disposal or partial disposal of a subsidiary.

Deficit

Represents the cumulative net earnings less distributed earnings of Vermilion Energy Inc.

Notes to the Consolidated Financial Statements for the year ended December 31, 2018 and 2017

tabular amounts in thousands of Canadian dollars, except share and per share amounts

1. Basis of presentation

Vermilion Energy Inc. and its subsidiaries (the “Company” or “Vermilion”) are engaged in the business of petroleum and natural gas exploration, development, acquisition, and production.

Vermilion was incorporated in Canada and the Company’s registered office and principal place of business is located at 3500, 520, 3rd Avenue SW, Calgary, Alberta, Canada.

These consolidated financial statements were approved and authorized for issuance by Vermilion’s Board of Directors on February 27, 2019.

2. Significant accounting policies

Accounting framework
The consolidated financial statements are prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”).

Principles of consolidation
The consolidated financial statements include the accounts of Vermilion Energy Inc. and its subsidiaries. Vermilion’s subsidiaries include entities in each of the jurisdictions that Vermilion operates as described in Note 4 including: Canada, France, Netherlands, Germany, Ireland (through an Irish Branch of a Cayman Islands incorporated company), Australia, the United States, Hungary, Slovakia, and Croatia. Vermilion Energy Inc. directly or indirectly through holding companies owns all of the voting securities of each material subsidiary. Transactions between Vermilion Energy Inc. and its subsidiaries have been eliminated.

Vermilion accounts for joint operations by recognizing the Company’s share of assets, liabilities, income, and expenses.

Exploration and evaluation assets
Vermilion classifies costs as exploration and evaluation (“E&E”) assets when they relate to exploring and evaluating an area for which the Company has the license or right to explore and extract resources. E&E costs may include: geological and geophysical costs; land and license acquisition costs; and costs for the drilling, completion, and testing of exploration wells.

E&E costs are reclassified to capital assets if the technical feasibility and commercial viability of the area can be determined. E&E assets are assessed for impairment prior to any reclassification. The technical feasibility and commercial viability of extracting the reserves is considered to be determinable when proved and probable reserves are identified.

Costs incurred prior to the acquisition of the legal rights to explore an area are expensed as incurred. If reserves are not found within the license area or the area is abandoned, the related E&E costs are depreciated over a period not greater than five years. If an exploration license expires prior to the commencement of exploration activities, the cost of the exploration license is written off through depreciation in the year of expiration.

Capital assets
Vermilion recognizes capital assets at cost less accumulated depletion, depreciation and impairment losses. Costs include directly attributable costs incurred for the drilling, completion, and tie-in of wells and the construction of production and processing facilities.

When components of capital assets are replaced, disposed of, or no longer in use, they are derecognized. Gains and losses on disposal of capital assets are determined by comparing the proceeds of disposal compared to the carrying amount.

Depletion and depreciation

Capital assets are grouped into depletion units, which are groups of assets within a specific production area that have similar economic lives. Depletion units represent the lowest level of disaggregation for which costs are accumulated for the purposes of calculating depletion and depreciation.

The net carrying value of each depletion unit is depleted using the unit of production method by reference to the ratio of production in the period to the total proved and probable reserves, taking into account the future development costs necessary to bring the applicable reserves into production.

For the purposes of the depletion calculations, oil and gas reserves are converted to a common unit of measure on the basis of their relative energy content based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent.

Impairment of capital assets and exploration and evaluation assets
Depletion units are aggregated into cash generating units ("CGUs") for impairment testing. CGUs are the lowest level for which there are identifiable cash inflows that are largely independent of cash inflows of other groups of assets. CGUs are reviewed for indicators of potential impairment at each reporting date.

E&E assets are tested for impairment when reclassified to capital assets or when indicators of potential impairment are identified. E&E assets are reviewed for indicators of potential impairment at each reporting date. If indicators of potential impairment are identified, E&E assets are tested for impairment as part of the CGU attributable to the jurisdiction in which the exploration area resides.

If an indicator of potential impairment exists, the CGU's carrying value is compared to its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value-in-use. If the carrying amount of a CGU exceeds its recoverable amount, an impairment loss is recognized to reduce the carrying value of the CGU to its recoverable amount.

If an impairment loss has been recognized in a prior period, an assessment is performed at each reporting date to determine if there are indicators that the circumstances which led to the impairment loss have reversed. If the change in circumstances results in the recoverable amount being higher than the carrying value after the impairment loss, then the impairment loss (net of depletion that would otherwise have been recorded) is reversed.

Lease obligations and right-of-use assets
A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the lease commencement date, a lease obligation is recognized at the present value of future lease payments, typically using the applicable incremental borrowing rate. A corresponding right-of-use asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs. Vermilion does not recognize leases for short-term leases with a lease term of 12 months or less, or leases for low-value assets.

Payments are applied against the lease obligation and interest expense is recognized on the lease obligations using the effective interest rate method. Depreciation is recognized on the right-of-use asset over the lease term.

Cash and cash equivalents
Cash and cash equivalents include cash on deposit with financial institutions and guaranteed investment certificates.

Crude oil inventory
Crude oil inventory is valued at the lower of cost or net realizable value. The cost of crude oil inventory produced includes related operating expense, royalties, and depletion determined on a weighted-average basis.

Asset retirement obligations
Vermilion recognizes a provision for asset retirement obligations when an event occurs giving rise to an obligation of uncertain timing or amount. Asset retirement obligations are recognized on the consolidated balance sheet as a long-term liability with a corresponding increase to E&E or capital assets.

Asset retirement obligations reflect the present value of estimated future settlement costs. The discount rate used to calculate the present value is specific to the jurisdiction the obligation relates to and is reflective of current market assessment of the time value of money and risks specific to the liabilities that have not been reflected in the cash flow estimates.

Asset retirement obligations are remeasured at each reporting period to reflect changes in market rates and estimated future settlement costs. Asset retirement obligations are increased each reporting period to reflect the passage of time with a corresponding charge to accretion expense.

Revenue recognition
Revenue associated with the sale of crude oil and condensate, natural gas, and natural gas liquids is measured based on the consideration specified in contracts with customers.

Revenue from contracts with customers is recognized when or as Vermilion satisfies a performance obligation by transferring control of crude oil and condensate, natural gas, or natural gas liquids to a customer at contractually specified transfer points.

This transfer coincides with title passing to the customer and the customer taking physical possession of the commodity. Vermilion principally satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

Vermilion invoices customers for delivered products monthly and payment occurs shortly thereafter. Vermilion does not have any contracts where the period between the transfer of control of the commodity to the customer and payment by the customer exceeds one year. As a result, Vermilion does not adjust its revenue transactions to reflect significant financing components.

Financial instruments
On initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods depends on the classification of the financial instrument as described below:

- Fair value through profit or loss: Financial instruments under this classification include cash and cash equivalents and derivative assets and liabilities.
- Amortized cost: Financial instruments under this classification include accounts receivable, accounts payable and accrued liabilities, dividends payable, lease obligations, and long-term debt.

Accounts receivable are measured net of a loss allowance equal to the lifetime expected credit loss.

Equity based compensation
Equity based compensation expense results from equity-settled awards issued under Vermilion’s long-term share-based compensation plans as well as the grant date fair value of Vermilion common shares issued under the Company’s bonus and employee share savings plans.

Vermilion's long-term share-based compensation plans consist of the Vermilion Incentive Plan (“VIP”) and a security-based compensation arrangement ("Five-Year Compensation Arrangement"). Equity-settled awards issued under the VIP vest over a period of one to three years while awards issued under the Five-Year Compensation Arrangement vest in the fifth year following the grant date. Awards under both plans are adjusted upon vesting by a performance factor determined by the Company’s Board of Directors. Equity based compensation expense for both plans is recognized over the vesting period with a corresponding adjustment to contributed surplus. The expense recognized is based on the grant date fair value of the awards, an estimate of the performance factor that will be achieved, and an estimate of forfeiture rates based on historical vesting data. Dividends notionally accrue to the awards and are excluded in the determination of grant date fair values. Upon vesting, the amount recognized in contributed surplus is reclassified to shareholders’ capital.

The grant date fair value of the equity-settled awards issued under the VIP and the Five-Year Compensation Arrangement and the grant date fair value of Vermilion common shares issued under the Company’s bonus and employee share savings plans are determined as the closing price of Vermilion’s common shares on the Toronto Stock Exchange on the grant date.

Per share amounts
Basic net earnings per share is calculated by dividing net earnings by the weighted-average number of shares outstanding during the period.

Diluted net earnings per share is calculated by dividing net earnings by the diluted weighted-average number of shares outstanding during the period. The diluted weighted-average number of shares outstanding is the sum of the basic weighted-average number of shares outstanding and (to the extent inclusion reduces diluted net earnings per share) the number of shares issuable for equity-settled awards determined using the treasury stock method. The treasury stock method assumes that the unrecognized equity based compensation expense are deemed proceeds used to repurchase Vermilion common shares at the average market price during the period.

Foreign currency translation
Vermilion Energy Inc.’s functional and presentation currency is the Canadian dollar. Vermilion has subsidiaries that transact and operate in countries other than Canada and have functional currencies other than the Canadian dollar.

Foreign currency translation includes the translation of foreign currency transactions and the translation of foreign operations.

Foreign currency transaction translation occur when translating transactions and balances in foreign currencies to the applicable functional currency of Vermilion Energy Inc. and its subsidiaries. Gains and losses from foreign currency transactions are recorded as foreign exchange gains or losses. Foreign currency transaction translation occurs as follows:

- Income and expenses are translated at the prevailing rates on the date of the transaction
- Non-monetary assets or liabilities are carried at the prevailing rates on the date of the transaction
- Monetary items, including intercompany loans that are not deemed to represent net investments in a foreign subsidiary, are translated at the prevailing rates at the balance sheet date

Foreign operation translation occurs when translating the financial statements of non-Canadian functional currency subsidiaries to the Canadian dollar and when translating intercompany loans that are deemed to represent net investments in a foreign subsidiary. Gains and losses from foreign operation translations are recorded as currency translation adjustments. Foreign operation translations occur as follows:

- Income and expenses are translated at the average exchange rates for the period
- Assets and liabilities are translated at the prevailing rates on the balance sheet date.

Income taxes
Deferred tax assets and liabilities are calculated using the balance sheet method. Deferred tax assets and liabilities are recognized for the estimated effect of any temporary differences between the amounts recognized on Vermilion's consolidated balance sheet and the respective tax basis. This calculation uses enacted or substantively enacted tax rates that are expected to be in effect when the temporary differences are expected to reverse. The effect of a change in tax rates on deferred taxes is recognized in the period the related legislation is substantively enacted.

Deferred tax assets are recognized to the extent that it is probable that future taxable profits will be available against which the deductible temporary differences can be used. Deferred tax assets are reviewed at each reporting date and are reduced to the extent it is no longer probable that the related tax benefit will be realized.

Business combinations
Acquisitions of corporations or groups of assets are accounted for as business combinations using the acquisition method if the acquired assets constitute a business. Under the acquisition method, assets acquired and liabilities assumed in a business combination (with the exception of deferred tax assets and liabilities) are measured at their fair value. Deferred tax assets or liabilities arising from the assets acquired and liabilities assumed are measured in accordance with the policies described in "Income taxes" above.

If applicable, the excess or deficiency of net assets acquired compared to consideration paid is recognized as a gain on business combination or as goodwill on the consolidated balance sheet. Acquisition-related costs incurred to effect a business combination are expensed in the period incurred.

Segmented information
Vermilion has a decentralized business unit structure designed to manage assets in each country the Company operates in. Each of Vermilion's operating segments derives its revenues solely from the production and sale of petroleum and natural gas.

Vermilion's Corporate segment aggregates costs incurred at the Company's Corporate head office located in Calgary, Alberta, Canada as well as costs incurred relating to Vermilion's exploration and production activities in Hungary, Slovakia, and Croatia (Central and Eastern Europe). These operating segments have similar economic characteristics as they do not currently generate material revenue.

Vermilion's chief operating decision maker regularly reviews fund flows from operations generated by each of Vermilion's operating segments. Fund flows from operations is a measure of profit or loss that provides the chief operating decision maker with the ability to assess the profitability of each operating segment and, correspondingly, the ability of each operating segment to fund its share of dividends, asset retirement obligations, and capital investments.

Management judgments and estimation uncertainty
The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Key areas where management has made judgments, estimates, and assumptions are described below.

The measurement of the fair value of capital assets acquired in a business combination and the determination of the recoverable amount of cash generating units:

- Calculating the fair value of capital assets acquired in a business combination and the recoverable amount of cash generating units (in the assessment of impairments or reversals of previous impairments if indicators of impairment or impairment reversal are identified) are based on estimated future commodity prices and estimated reserves and resources. Reserve and resource estimates are based on: engineering data, estimated future commodity prices, expected future rates of production, and assumptions regarding the timing and amount of future expenditures. Changes in these estimates and assumptions can directly impact the calculated fair value of capital assets acquired (and thus the resulting goodwill or gain on business combination) and the recoverable amount of a CGU (and thus the resulting impairment loss or recovery).
- In addition, the recoverable amount of a CGU is impacted by the composition of CGUs, which are subject to management's judgment of the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. The factors used by Vermilion to determine CGUs vary by jurisdiction due to their unique operating and geographic conditions. In general, Vermilion will assess the following factors: geographic proximity of the assets within a group to one another, geographic proximity of the group of assets to other groups of assets, homogeneity of the production from the group of assets and the sharing of infrastructure used to process and/or transport production. Changes in these judgments can directly impact the calculated recoverable amount of a CGU (and thus the resulting impairment loss or recovery).

The measurement of the carrying value of asset retirement obligations on the balance sheet, including the fair value and subsequent carrying value of asset retirement obligations assumed in a business combination:

- Asset retirement obligations are based on judgments regarding regulatory requirements, estimates of future costs, assumptions on the expected timing of expenditures, and estimates of the underlying risk inherent to the obligation. The carrying balance of asset retirement obligations and accretion expense may differ due to changes in: laws and regulations, technology, the expected timing of expenditures, and market conditions affecting the discount rate applied.

The recognition and measurement of deferred tax assets and liabilities:

- Tax interpretations, regulations, and legislation in the various jurisdictions in which Vermilion and its subsidiaries operate are subject to change and interpretation. Changes in laws and interpretations can affect the timing of the reversal of temporary tax differences, the tax rates in effect when such differences reverse and Vermilion's ability to use tax losses and other tax pools in the future. The Company's income tax filings are subject to audit by taxation authorities in numerous jurisdictions and the results of such audits may increase or decrease the tax liability. The determination of tax amounts recognized in the consolidated financial statements are based on management's assessment of the tax positions, which includes consideration of their technical merits, communications with tax authorities and management's view of the most likely outcome.
- The extent to which deferred tax assets are recognized are based on estimates of future profitability. These estimates are based on estimated future commodity prices and estimates of reserves. Judgments, estimates, and assumptions inherent in reserve estimates are described above.

The measurement of lease obligations and corresponding right-of-use assets:

- The measurement of lease obligations are subject to management's judgments of the applicable incremental borrowing rate and the expected lease term. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and expected lease terms. Applicable incremental borrowing rates are based on judgments of the economic environment, term, currency, and the underlying risk inherent to the asset. Lease terms are based on assumptions regarding cancellation and extension terms that allow for operational flexibility based on future market conditions.

3. Changes in accounting pronouncements

IFRS 9 "Financial instruments"

On January 1, 2018, Vermilion adopted IFRS 9 *"Financial instruments"* as issued by the IASB. IFRS 9 includes a new classification and measurement approach for financial assets and a forward-looking 'expected credit loss' model. The adoption of IFRS 9 did not have a material impact on Vermilion's consolidated financial statements.

IFRS 15 "Revenue from contracts with customers"
On January 1, 2018, Vermilion adopted IFRS 15 "*Revenue from contracts with customers*". IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized.

Vermilion adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15.

IFRS 15 requires additional disclosure relating to the disaggregation of revenue - this additional disclosure is included in Note 4 (Segmented Information).

IFRS 16 "Leases"
Vermilion has elected to early adopt IFRS 16 effective January 1, 2018. IFRS 16 introduces a single lease accounting model for lessees which requires a right-of-use asset and lease liability to be recognized on the balance sheet for contracts that are, or contain, a lease.

Vermilion adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the standard was recognized as a $97.1 million increase to right-of-use assets (included in "Capital assets") with a corresponding increase to lease obligations (the non-current portion of $86.1 million recorded in "lease obligations" and the current $11.0 million portion recorded in "Accounts payable and accrued liabilities"). The right-of-use assets recognized were measured at amounts equal to the lease obligations. The weighted average incremental borrowing rate used to determine the lease obligation at adoption was approximately 5.4%. The right-of-use assets and lease obligations recognized largely relate to the Company's head office lease in Calgary and long-term leases for oil storage facilities in France.

The adoption of IFRS 16 included the following elections:

- Vermilion elected to retain the classification of contracts previously identified as leases under IAS 17 and IFRIC 4.
- Vermilion elected to use hindsight in determining lease term.
- Vermilion elected to not apply lease accounting to certain leases for which the lease term ends within 12 months of the date of initial application.

As at December 31, 2017, Vermilion disclosed operating lease commitments of $40.2 million, which would have resulted in a lease obligation of $34.3 million when discounted at the weighted average incremental borrowing rate at adoption of IFRS 16 of 5.4%. The total current and non-current lease liability recognized on January 1, 2018 of $97.1 million represented an increase of $62.8 million compared to the disclosed operating lease commitments due the application of IFRS 16 in determining lease terms.

4. Segmented information

Vermilion has three major customers within the France, Netherlands, and Ireland operating segments that each comprise in excess of 10% of Vermilion's consolidated revenues. Substantially all sales in the France, Netherlands, and Ireland operating segments for the years ended December 31, 2018 and 2017 were to one customer in each respective segment.

				Year Ended December 31, 2018					
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Total assets	3,060,291	918,398	277,348	284,063	709,585	263,739	407,323	349,924	6,270,671
Drilling and development	277,857	79,451	17,963	10,863	224	75,638	40,837	1,009	503,842
Exploration and evaluation	—	307	(480)	4,943	—	—	—	9,602	14,372
Crude oil and condensate sales	541,844	360,471	2,462	32,704	—	150,733	31,142	—	1,119,356
NGL sales	56,554	—	—	—	—	—	4,622	—	61,176
Natural gas sales	72,774	131	163,454	49,745	205,150	—	2,701	3,630	497,585
Royalties	(84,696)	(46,781)	(3,181)	(6,626)	—	—	(10,070)	(813)	(152,167)
Revenue from external customers	586,476	313,821	162,735	75,823	205,150	150,733	28,395	2,817	1,525,950
Transportation	(29,912)	(10,426)	—	(6,420)	(5,129)	—	—	—	(51,887)
Operating	(177,499)	(54,690)	(26,681)	(23,048)	(15,366)	(53,199)	(6,421)	(110)	(357,014)
General and administration	(6,057)	(14,170)	(1,947)	(7,401)	(8,386)	(4,918)	(6,306)	(2,744)	(51,929)
PRRT	—	—	—	—	—	(4,824)	—	—	(4,824)
Corporate income taxes	—	(15,084)	(16,561)	—	—	(6,595)	—	(513)	(38,753)
Interest expense	—	—	—	—	—	—	—	(72,759)	(72,759)
Realized loss on derivative instruments	—	—	—	—	—	—	—	(111,258)	(111,258)
Realized foreign exchange gain	—	—	—	—	—	—	—	243	243
Realized other income	—	—	—	—	—	—	—	883	883
Fund flows from operations	**373,008**	**219,451**	**117,546**	**38,954**	**176,269**	**81,197**	**15,668**	**(183,441)**	**838,652**

				Year Ended December 31, 2017					
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA	Corporate	Total
Total assets	1,542,193	831,783	203,929	295,026	667,068	236,677	73,867	124,422	3,974,965
Drilling and development	148,667	71,087	15,107	6,165	551	29,942	19,074	—	290,593
Exploration and evaluation	—	2,294	16,468	3,366	—	—	—	7,728	29,856
Crude oil and condensate sales	209,560	268,102	1,864	23,554	—	154,391	14,605	—	672,076
NGL sales	37,809	—	—	—	—	—	456	—	38,265
Natural gas sales	83,534	1	106,196	45,142	153,330	—	294	—	388,497
Royalties	(33,258)	(28,565)	(1,722)	(6,655)	—	—	(4,276)	—	(74,476)
Revenue from external customers	297,645	239,538	106,338	62,041	153,330	154,391	11,079	—	1,024,362
Transportation	(17,368)	(14,627)	—	(6,207)	(5,205)	—	(41)	—	(43,448)
Operating	(80,444)	(51,002)	(21,212)	(20,176)	(17,596)	(50,139)	(1,698)	—	(242,267)
General and administration	(9,604)	(13,585)	(2,212)	(7,767)	(2,320)	(8,194)	(4,341)	(6,350)	(54,373)
PRRT	—	—	—	—	—	(19,819)	—	—	(19,819)
Corporate income taxes	—	(10,556)	3,331	—	—	(4,536)	—	(527)	(12,288)
Interest expense	—	—	—	—	—	—	—	(57,313)	(57,313)
Realized gain on derivative instruments	—	—	—	—	—	—	—	4,721	4,721
Realized foreign exchange gain	—	—	—	—	—	—	—	2,316	2,316
Realized other income	—	—	—	—	—	—	—	674	674
Fund flows from operations	**190,229**	**149,768**	**86,245**	**27,891**	**128,209**	**71,703**	**4,999**	**(56,479)**	**602,565**

Reconciliation of fund flows from operations to net earnings:

($M)	Year Ended Dec 31, 2018	Dec 31, 2017
Fund flows from operations	**838,652**	602,565
Accretion	**(31,219)**	(26,971)
Depletion and depreciation	**(609,056)**	(491,683)
Gain on business combinations	**128,208**	—
Unrealized gain (loss) on derivative instruments	**109,326**	(1,062)
Equity based compensation	**(60,746)**	(61,579)
Unrealized foreign exchange (loss) gain	**(63,243)**	71,742
Unrealized other expense	**(801)**	(637)
Deferred tax	**(39,471)**	(30,117)
Net earnings	**271,650**	62,258

5. Business combinations

Private Producer in Southeast Saskatchewan and Southwest Manitoba
On February 15, 2018, Vermilion acquired all of the issued and outstanding common shares of a private producer with assets in southeast Saskatchewan and southwest Manitoba. The acquisition comprised of light oil producing fields near Vermilion’s existing operations in southeast Saskatchewan. The acquisition complements Vermilion’s existing southeast Saskatchewan operations and aligns with the Company's sustainable growth-and-income model. The acquisition was funded through Vermilion’s revolving credit facility.

The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are detailed in the table below.

($M)	Consideration
Cash paid to vendor	53,288
Total consideration	**53,288**

($M)	Allocation of consideration
Capital assets	67,549
Deferred tax assets	26,914
Acquired working capital	1,577
Long-term debt	(38,300)
Asset retirement obligations	(4,452)
Net assets acquired	**53,288**

For the year ended December 31, 2018, the acquisition contributed revenues of $18.7 million and net earnings of $6.7 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $2.9 million and net earnings would have increased by $1.0 million for the year ended December 31, 2018.

Spartan Energy Corp.
On May 28, 2018, Vermilion acquired all of the issued and outstanding common shares of Spartan Energy Corp., a publicly traded oil and gas producer with light oil producing properties in southeast Saskatchewan as well as other areas in Saskatchewan, Alberta, and Manitoba. The acquisition increases Vermilion’s position in southeast Saskatchewan and aligns with the Company's sustainable growth-and-income model.

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). Acquisition-related costs of $1.3 million were incurred in the year ended December 31, 2018.

The total consideration paid and the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are detailed in the table below.

($M)	Consideration
Shares issued for acquisition	1,235,221
Total consideration	**1,235,221**

($M)	Allocation of consideration
Capital assets	1,401,686
Deferred tax assets	123,813
Long-term debt	(150,196)
Asset retirement obligations	(92,149)
Lease obligations	(25,455)
Assumed working capital deficit	(22,478)
Net assets acquired	**1,235,221**

For the year ended December 31, 2018, the acquisition contributed revenues of $242.1 million and net earnings of $45.1 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $182.4 million and net earnings would have increased by $35.0 million for the year ended December 31, 2018.

Assets in Wyoming

In August 2018, Vermilion acquired oil and gas producing assets and mineral leasehold land from a private oil company for total cash consideration of approximately $189 million. The assets are located in Campbell County, Wyoming in the Powder River Basin, approximately 65 kilometres northwest of Vermilion's existing operations. The acquired assets complement Vermilion's existing Powder River operations and align with the Company's sustainable growth-and-income model. The acquisition was funded through Vermilion's revolving credit facility.

The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are detailed in the table below.

($M)	Consideration
Cash paid to vendor	189,014
Total consideration	**189,014**

($M)	Allocation of consideration
Capital assets	284,333
Deferred tax liability	(19,019)
Asset retirement obligations	(4,821)
Assumed working capital deficit	(2,651)
Net assets acquired	**257,842**
Gain on business combination	(68,828)
Total net assets acquired, net of gain on business combination	**189,014**

The gain on the business combination primarily resulted from the recognition of additional reserve value when the acquisition closed compared to the estimated value when Vermilion entered into the purchase and sale agreement and the acquisition price was determined.

For the year ended December 31, 2018, the acquisition contributed revenues of $11.6 million and net earnings of $0.3 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $11.1 million and net earnings would have decreased by $0.1 million for the year ended December 31, 2018.

Shell E&P Ireland Limited
In December 2018, Vermilion acquired all of the issued and outstanding common shares of Shell E&P Ireland Limited, along with an incremental 1.5% working interest in the Corrib Natural Gas Project ("Corrib") in Ireland from Nephin Energy Holdings Limited, a wholly owned subsidiary of Canada Pension Plan Investment Board. The acquisition increases Vermilion's total ownership in Corrib to 20% and aligns with the Company's sustainable growth-and-income model. In addition to this transaction, Vermilion has assumed operatorship of Corrib.

The total consideration paid and the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are detailed in the table below.

($M)	Consideration
Cash paid to vendor	40,805
Cash acquired	(82,116)
Contingent consideration	290
Total consideration	**(41,021)**

($M)	Allocation of consideration
Capital assets	53,368
Deferred tax assets	4,239
Assumed working capital deficit	(35,449)
Lease obligations	(2,234)
Asset retirement obligations	(1,565)
Net assets acquired	**18,359**
Gain on business combination	(59,380)
Total net assets acquired, net of gain on business combination	**(41,021)**

The fair value of the contingent consideration obligation is estimated to be approximately $0.3 million based on estimated future commodity prices and estimated reserves. Maximum contingent payments are €5.8 million (approximately $9.1 million) through 2025.

The gain on the business combination primarily resulted from increases in working capital and the fair value of capital assets from when the purchase and sale agreement was entered into in July 2017 and when the acquisition closed in December 2018.

For the year ended December 31, 2018, the acquisition contributed revenues of $1.3 million and net earnings of $0.4 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $15.2 million and net earnings would have increased by $4.3 million for the year ended December 31, 2018.

Minor acquisitions
Vermilion completed a number of minor acquisitions during the year ended December 31, 2018 for total cash consideration of $56.0 million, in which $147.4 million of capital assets, $28.6 million of exploration and evaluation assets, and $104.0 million of asset retirement obligations were recognized.

6. Capital assets

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

($M)	2018	2017
Balance at January 1	**3,337,965**	3,433,245
Acquisitions	**1,975,327**	25,390
Additions	**503,842**	290,593
Increase in right-of-use assets	**98,343**	—
Transfers from exploration and evaluation assets	**29,615**	8,187
Depletion and depreciation	**(605,994)**	(479,698)
Changes in asset retirement obligations	**(100,876)**	(48,187)
Foreign exchange	**78,651**	108,435
Balance at December 31	**5,316,873**	3,337,965
Cost	**9,202,604**	6,539,052
Accumulated depletion and depreciation	**(3,885,731)**	(3,201,087)
Carrying amount at December 31	**5,316,873**	3,337,965

The following table discloses the carrying balance and depreciation charge relating to right-of-use assets by class of underlying asset as at and for the year ended December 31, 2018:

($M)	Depreciation	Balance
Office space	**9,119**	**62,279**
Gas processing facilities	**5,491**	**41,788**
Oil storage facilities	**2,728**	**20,758**
Vehicles and equipment	**2,020**	**9,121**
Total	**19,358**	**133,946**

2018 and 2017 impairment assessment

As at December 31, 2018 and 2017, Vermilion did not identify any indicators of impairment.

7. Exploration and evaluation assets

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

($M)	2018	2017
Balance at January 1	**292,278**	274,830
Acquisitions	**28,572**	2,247
Additions	**14,372**	29,856
Changes in asset retirement obligations	**629**	(30)
Transfers to capital assets	**(29,615)**	(8,187)
Depreciation	**(5,942)**	(11,727)
Foreign exchange	**3,001**	5,289
Balance at December 31	**303,295**	292,278
Cost	**371,015**	354,615
Accumulated depreciation	**(67,720)**	(62,337)
Carrying amount at December 31	**303,295**	292,278

8. Asset retirement obligations

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

($M)	2018	2017
Balance at January 1	**517,180**	525,022
Additional obligations recognized	**211,580**	3,273
Changes in estimated abandonment timing and costs	**(98,158)**	(48,904)
Obligations settled	**(15,765)**	(9,334)
Accretion	**31,219**	26,971
Changes in discount rates	**(6,646)**	(2,586)
Foreign exchange	**10,754**	22,738
Balance at December 31	**650,164**	517,180

Vermilion has estimated the asset retirement obligations based on a total undiscounted future liability of $2.6 billion (2017 - $1.6 billion). These payments are expected to be made between 2020 and 2078, with the majority of spending occurring between 2029 and 2036 ($0.6 billion), 2047 to 2055 ($0.6 billion), and 2063 and 2068 ($0.9 billion). Inflation rates used in determining the cash flow estimates were between 0.5% and 2.9% (2017 - between 0.6% and 2.2%). Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 4.0% (2017 - 3.8%) added to risk-free rates based on long-term, risk-free government bonds.

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

	Dec 31, 2018	Dec 31, 2017
Canada	**2.2%**	2.3%
France	**1.6%**	1.8%
Netherlands	**0.4%**	0.5%
Germany	**0.9%**	1.0%
Ireland	**1.6%**	0.4%
Australia	**2.6%**	2.9%
USA	**2.7%**	2.4%

A 0.5% increase/decrease in the discount rate applied to asset retirement obligations would decrease/increase asset retirement obligations by approximately $55.0 million. A one-year increase/decrease in the expected timing of abandonment spend would decrease/increase asset retirement obligations by approximately $25.0 million.

9. Derivative instruments

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

	Year Ended	
($M)	Dec 31, 2018	Dec 31, 2017
Fair value of contracts, beginning of year	**(70,713)**	(69,651)
Reversal of opening contracts settled during the year	**57,719**	43,324
Assumed in acquisitions	**(274)**	—
Realized (loss) gain on contracts settled during the year	**(111,258)**	4,721
Unrealized gain (loss) during the year on contracts outstanding at the end of the year	**51,607**	(44,386)
Net receipt from counterparties on contract settlements during the year	**111,258**	(4,721)
Fair value of contracts, end of year	**38,339**	(70,713)
Comprised of:		
Current derivative asset	**95,667**	17,988
Current derivative liability	**(41,016)**	(78,905)
Non-current derivative asset	**1,215**	2,552
Non-current derivative liability	**(17,527)**	(12,348)
Fair value of contracts, end of year	**38,339**	(70,713)

The loss (gain) on derivative instruments for 2018 and 2017 were comprised of the following:

	Year Ended	
($M)	Dec 31, 2018	Dec 31, 2017
Realized loss (gain) on contracts settled during the year	**111,258**	(4,721)
Reversal of opening contracts settled during the year	**(57,719)**	(43,324)
Unrealized (gain) loss on contracts outstanding at the end of the year	**(51,607)**	44,386
Loss (gain) on derivative instruments	**1,932**	(3,659)

Please refer to Note 19 (Supplemental information) for a listing of Vermilion's outstanding derivative instruments as at December 31, 2018.

10. Leases

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

	As at	
($M)	Dec 31, 2018	Dec 31, 2017
Less than 1 year	**30,641**	6,680
1 - 3 years	**50,024**	10,207
4 - 5 years	**34,313**	4,665
After 5 years	**42,739**	3,351
Total lease payments	**157,717**	24,903
Amounts representing interest	**(24,583)**	(3,526)
Present value of net lease payments	**133,134**	21,377
Current portion of lease obligations	**(24,945)**	(5,570)
Non-current portion of lease obligations	**108,189**	15,807

The significant increase in total lease payments as at December 31, 2018 compared to December 31, 2017 primarily relates to the adoption of IFRS 16 effective January 1, 2018 and lease obligations assumed on acquisitions. Please refer to Note 3 (Changes to accounting pronouncements), Note 5 (Business combinations), and Note 6 (Capital assets) for additional information.

For the year ended December 31, 2018, interest expense of $7.2 million and total cash outflow of $28.0 million were recognized relating to lease obligations.

11. Taxes

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

	As at	
($M)	Dec 31, 2018	Dec 31, 2017
Deferred tax assets:		
Non-capital losses	**487,398**	342,202
Capital assets	**(296,591)**	(294,178)
Asset retirement obligations	**38,429**	28,056
Derivative contracts	**(11,937)**	10,164
Unrealized foreign exchange	**(1,873)**	(7,927)
Other	**3,985**	2,007
Deferred tax assets	**219,411**	80,324
Deferred tax liabilities:		
Capital assets	**(319,553)**	(259,236)
Non-capital losses	**57,785**	34,703
Asset retirement obligations	**(51,031)**	(27,868)
Unrealized foreign exchange	**(10,715)**	(13,355)
Derivative contracts	**—**	11,386
Other	**5,380**	1,262
Deferred tax liabilities	**(318,134)**	(253,108)

Income tax expense differs from the amount that would have been expected if the reported earnings had been subject only to the statutory Canadian income tax rate as follows:

($M)	Year Ended Dec 31, 2018	Dec 31, 2017
Earnings before income taxes	**354,698**	124,482
Canadian corporate tax rate	**27.0%**	27.0%
Expected tax expense	**95,768**	33,610
Increase (decrease) in taxes resulting from:		
Petroleum resource rent tax rate (PRRT) differential (1)	**5,349**	3,531
Foreign tax rate differentials (1), (2)	**3,086**	7,146
Equity based compensation expense	**13,883**	10,343
Amended returns and changes to estimated tax pools and tax positions	**(873)**	(17,246)
Statutory rate changes and the estimated reversal rates associated with temporary differences (3)	**—**	(16,449)
(Re-recognition) de-recognition of deferred tax assets	**(26,931)**	44,608
Adjustment for uncertain tax positions	**8,080**	2,191
Gain on business combinations	**(28,812)**	—
Other non-deductible items	**13,498**	(5,510)
Provision for income taxes	**83,048**	62,224

(1) In Australia, current taxes include both corporate income tax rates and PRRT. Corporate income tax rates were applied at a rate of 30% and PRRT was applied at a rate of 40%.

(2) The applicable tax rates for 2018 were: 34.4% in France, 50.0% in the Netherlands, 30.2% in Germany, 25.0% in Ireland, and 21.0% in the United States.

(3) On December 22, 2017, the Tax Cuts and Jobs Act was signed into law in the United States reducing the U.S. federal corporate income tax rate from 35% to 21%. On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French standard corporate income tax rate from 34.43% to 25.825% by 2022. On December 18, 2018, the Dutch government approved the 2019 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% to 20.5% by 2021, with the first reduction planned for 2020 to 22.55%. Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not expected to have a material impact to Vermilion taxes in the Netherlands.

At December 31, 2018, Vermilion had $2.6 billion (2017 - $2.0 billion) of unused tax losses of which $1.1 billion (2017 - $0.5 billion) relates to Vermilion's Canada segment and expire between 2025 and 2038 and $1.3 billion (2017 - $1.3 billion) relates to Vermilion's Ireland segment and do not expire. The year-over-year increase in unused tax losses in Vermilion's Canada segment was the result of tax losses acquired in the business combinations described in Note 5.

At December 31, 2018, Vermilion re-recognized $90.6 million (2017 - de-recognized $145.6 million) of deductible temporary differences relating to the aforementioned non-expiring tax loss pools in Ireland based on the Company's expected ability to fully utilize such losses based on commodity price forecasts in effect as at December 31, 2018.

The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have not been recognized as at December 31, 2018 is approximately $0.5 billion (2017 – approximately $0.4 billion).

12. Long-term debt

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

($M)	As at Dec 31, 2018	Dec 31, 2017
Revolving credit facility	**1,392,206**	899,595
Senior unsecured notes	**404,001**	370,735
Long-term debt	**1,796,207**	1,270,330

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

($M)	2018	2017
Balance at January 1	**1,270,330**	1,362,192
Borrowings (repayments) on the revolving credit facility	**251,155**	(450,646)
Issuance of senior unsecured notes	**—**	391,906
Assumed on acquisitions [1]	**188,496**	—
Amortization of transaction costs and prepaid interest	**2,286**	2,012
Foreign exchange	**83,940**	(35,134)
Balance at December 31	**1,796,207**	1,270,330

[1] Pursuant to the acquisitions described in Note 5 (Business Combinations), Vermilion assumed the credit facilities of the acquired companies and immediately extinguished them following the respective acquisitions using proceeds from Vermilion's revolving credit facility.

Revolving credit facility

At December 31, 2018, Vermilion had in place a bank revolving credit facility maturing May 31, 2022 with the following terms:

	As at	
($M)	Dec 31, 2018	Dec 31, 2017
Total facility amount	**1,800,000**	1,400,000
Amount drawn	**(1,392,206)**	(899,595)
Letters of credit outstanding	**(15,400)**	(7,400)
Unutilized capacity	**392,394**	493,005

The facility can be extended from time to time at the option of the lenders and upon notice from Vermilion. If no extension is granted by the lenders, the amounts owing pursuant to the facility are due at the maturity date. The facility is secured by various fixed and floating charges against the subsidiaries of Vermilion.

The facility bears interest at a rate applicable to demand loans plus applicable margins.

As at December 31, 2018, the revolving credit facility was subject to the following financial covenants:

		As at	
Financial covenant	Limit	Dec 31, 2018	Dec 31, 2017
Consolidated total debt to consolidated EBITDA	4.0	**1.72**	1.87
Consolidated total senior debt to consolidated EBITDA	3.5	**1.34**	1.30
Consolidated total senior debt to total capitalization	55%	**30%**	32%

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

- Consolidated total debt: Includes all amounts classified as "Long-term debt" and "Lease obligations" (including the current portion included within "Accounts payable and accrued liabilities" but excluding operating leases as defined under IAS 17) on the balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certain other non-cash items, adjusted for the impact of the acquisition of a material subsidiary.
- Total capitalization: Includes all amounts classified as "Shareholders' equity" plus consolidated total debt as defined above.

As at December 31, 2018 and 2017, Vermilion was in compliance with the above covenants.

Senior unsecured notes

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

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

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

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

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

13. Shareholders' capital

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

	2018		2017	
Shareholders' Capital	Shares ('000s)	Amount ($M)	Shares ('000s)	Amount ($M)
Balance at January 1	**122,119**	**2,650,706**	118,263	2,452,722
Shares issued for acquisition	**27,883**	**1,234,676**	—	—
Shares issued for the Dividend Reinvestment Plan	**1,179**	**49,051**	2,429	110,493
Vesting of equity based awards	**1,025**	**54,057**	1,060	69,743
Shares issued for equity based compensation	**314**	**12,565**	197	9,270
Share-settled dividends on vested equity based awards	**184**	**7,773**	170	8,478
Balance at December 31	**152,704**	**4,008,828**	122,119	2,650,706

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

Dividends are approved by the Board of Directors and are paid monthly. Dividends declared to shareholders for the year ended December 31, 2018 were $388.1 million or $2.72 per common share (2017 - $311.4 million or $2.58 per common share).

Subsequent to the end of year-end and prior to the consolidated financial statements being authorized for issue on February 27, 2019, Vermilion declared dividends of $70.3 million or $0.230 per share for each of January and February of 2019.

14. Capital disclosures

Vermilion defines capital as net debt (long-term debt plus net working capital) and shareholders' capital. Vermilion excludes from its definition of capital any obligations secured by an offsetting asset, such as lease obligations.

Vermilion monitors the ratio of net debt to fund flows from operations. As at December 31, 2018, our ratio of net debt to trailing fund flows from operations is 2.30 (2017 - 2.28). Vermilion manages the ratio of net debt to fund flows from operations (refer to Note 4 - Segmented Information) by aligning capital expenditures, dividends, and asset retirement obligations with expected fund flows from operations. Vermilion intends for the ratio of net debt to fund flows from operations to trend towards 1.5 over time.

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

($M except as indicated)	Year Ended Dec 31, 2018	Dec 31, 2017
Long-term debt	**1,796,207**	1,270,330
Current liabilities	**563,199**	363,306
Current assets	**(429,877)**	(261,846)
Net debt	**1,929,529**	1,371,790
Ratio of net debt to fund flows from operations	**2.30**	2.28

15. Equity based compensation

The following table summarizes the number of awards outstanding under the VIP and the Five-Year Compensation Arrangement:

Number of Awards ('000s)	2018	2017
Opening balance	**1,685**	1,738
Granted	**932**	563
Vested	**(520)**	(539)
Forfeited	**(166)**	(77)
Closing balance	**1,931**	1,685

For the year ended December 31, 2018, the awards granted had a weighted average fair value of $40.57 (2017 - $49.44). Equity based compensation expense is calculated based on the number of awards outstanding multiplied by the estimated performance factor that will be realized upon vesting (2018 - 1.9; 2017 - 1.9) adjusted by an estimated annual forfeiture rate (2018 - 4.6%; 2017 - 4.4%). Equity based compensation expense of $48.2 million was recorded during the year ended December 31, 2018 (2017 - $52.3 million) relating to the awards.

As at December 31, 2018, 36,845 awards included in the closing balance related to the Five-Year Compensation Arrangement.

16. Per share amounts

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

($M except per share amounts)	Year Ended Dec 31, 2018	Dec 31, 2017
Net earnings	**271,650**	62,258
Basic weighted average shares outstanding ('000s)	**140,619**	120,582
Dilutive impact of equity based compensation ('000s)	**1,716**	1,826
Diluted weighted average shares outstanding ('000s)	**142,335**	122,408
Basic earnings per share	**1.93**	0.52
Diluted earnings per share	**1.91**	0.51

17. Financial instruments

Classification of financial instruments

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

	As at Dec 31, 2018		As at Dec 31, 2017	
($M)	Carrying value	Fair value	Carrying value	Fair value
Fair value through profit or loss				
Cash and cash equivalents	**26,809**	**26,809**	46,561	46,561
Derivative assets	**96,882**	**96,882**	20,540	20,540
Derivative liabilities	**(58,543)**	**(58,543)**	(91,253)	(91,253)
Amortized cost				
Accounts receivable	**260,322**	**260,322**	165,760	165,760
Accounts payable and accrued liabilities	**(449,651)**	**(449,651)**	(219,084)	(219,084)
Dividends payable	**(35,122)**	**(35,122)**	(26,256)	(26,256)
Long-term debt	**(1,796,207)**	**(1,781,809)**	(1,270,330)	(1,274,891)

On January 1, 2018, Vermilion adopted IFRS 9 "Financial instruments". As a result, Vermilion's financial instruments were re-categorized following IFRS 9's new measurement categories. There were no changes in the carry amounts of financial instruments as a result of this re-categorization. Under IAS 39 "Financial instruments: recognition and measurement", Vermilion's financial instruments were classified as follows:

- Cash and cash equivalents and derivative assets were classified as held for trading. Held for trading financial instruments were subsequently measured at fair value on the consolidated balance sheet with gains and losses recognized in net earnings.
- Accounts receivable were classified as loans and receivables while accounts payable and accrued liabilities, dividends payable, lease obligations, and long-term debt were classified as other financial liabilities. Loans and receivables and other financial liabilities were subsequently measured at amortized cost on the consolidated balance sheet.

Fair value measurements are categorized into a fair value hierarchy based on the lowest level input that is significant to the fair value measurement:

- Level 1 inputs are determined by reference to unadjusted quoted prices in active markets for identical assets or liabilities. Inputs used in fair value measurement of cash and cash equivalents and the senior unsecured notes are categorized as Level 1.
- Level 2 inputs are determined based on inputs other than unadjusted quoted prices that are observable, either directly or indirectly. The fair value of Vermilion's derivative assets and liabilities are determined using pricing models that incorporate future price forecasts (supported by prices from observable market transactions) and credit risk adjustments.
- Level 3 inputs are not based on observable market data. Vermilion does not have any financial instruments classified as Level 3.

There were no transfers between levels in the hierarchy in the years ended December 31, 2018 and 2017.

The carrying value of accounts receivable, accounts payable and accrued liabilities, and dividends payable are a reasonable approximation of their fair value due to the short maturity of these financial instruments. The carrying value of long-term debt outstanding on the revolving credit facility approximates its fair value due to the use of short-term borrowing instruments at market rates of interest.

Nature and Extent of Risks Associated with Financial Instruments

Vermilion is exposed to financial risks from its financial instruments. These financial risks include: market risk (includes commodity price risk, interest rate risk, and currency risk), credit risk, and liquidity risk.

Commodity price risk

Vermilion is exposed to commodity price risk on its derivative assets and liabilities which are used as part of the Company's risk management program to mitigate the effects of changes in commodity prices on future cash flows. While transactions of this nature relate to future petroleum and natural gas production, Vermilion does not designate these derivative assets and liabilities as accounting hedges. As such, changes in commodity prices impact the fair value of derivative instruments and the corresponding gains or losses recognized on derivative instruments.

Currency risk
Vermilion is exposed to currency risk on its financial instruments denominated in foreign currencies. These financial instruments include cash and cash equivalents, accounts receivables, accounts payables, lease obligations, long-term debt, derivative assets and derivative liabilities. These financial instruments are primarily denominated in the US dollar and the Euro. Vermilion monitors its exposure to currency risk and reviews whether the use of derivative financial instruments is appropriate to manage potential fluctuations in foreign exchange rates.

Interest rate risk
Vermilion is exposed to interest rate risk on its revolving credit facility, which consists of short-term borrowing instruments that bear interest at market rates. Thus, changes in interest rates could result in an increase or decrease in the amount paid by Vermilion to service this debt.

The following table summarizes the increase (positive values) or decrease (negative values) to net earnings before tax due to a change in the value of Vermilion's financial instruments as a result of a change in the relevant market risk variable. This analysis does not attempt to reflect any interdependencies between the relevant risk variables.

($M)	Dec 31, 2018	Dec 31, 2017
Currency risk - Euro to Canadian dollar		
$0.01 increase in strength of the Canadian dollar against the Euro	**(2,205)**	(4,607)
$0.01 decrease in strength of the Canadian dollar against the Euro	**2,205**	4,607
Currency risk - US dollar to Canadian dollar		
$0.01 increase in strength of the Canadian dollar against the US $	**2,981**	2,239
$0.01 decrease in strength of the Canadian dollar against the US $	**(2,981)**	(2,239)
Commodity price risk - Crude oil		
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(18,421)**	(21,616)
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**17,351**	19,845
Commodity price risk - European natural gas		
€ 0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	**(36,508)**	(32,642)
€ 0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	**33,005**	25,321

Credit risk:
Vermilion is exposed to credit risk on accounts receivable and derivative assets in the event that customers, joint operation partners, or counterparties fail to discharge their contractual obligations. As at December 31, 2018, Vermilion's maximum exposure to receivable credit risk was $357.2 million (December 31, 2017 - $186.3 million) which is the value of accounts receivable and derivative assets on the balance sheet.

Vermilion's accounts receivable primarily relates to customers and joint operations partners in the petroleum and natural gas industry. These amounts are subject to normal industry payment terms and credit risks. Vermilion manages these risks by monitoring the creditworthiness of customers and joint operations partners and, where appropriate, obtaining assurances such as parental guarantees and letters of credit. Vermilion determines the lifetime expected credit losses recognized on accounts receivable using a provision matrix. In preparing the provision matrix, the Company takes into account historical credit loss experience based on the aging of accounts receivable, adjusted as necessary for current and future petroleum and natural gas prices to the extent that changes in pricing may negatively impact the Company's customers and joint operations partners. The lifetime expected credit losses on accounts receivable as at December 31, 2018 and 2017 is not material. As at the balance sheet date, approximately 0.7% (2017 - 0.7%) of the accounts receivable balance was outstanding for more than 90 days. Vermilion considers the balance of accounts receivable to be collectible.

Vermilion's derivative assets primarily relates to the fair value of financial instruments used as part of the Company's risk management program to mitigate the effects of changes in commodity prices on future cash flows. Vermilion manages this risk by monitoring the creditworthiness of counterparties, transacting primarily with counterparties that have investment grade third party credit ratings, and by limiting the concentration of financial exposure to individual counterparties. As a result, Vermilion has not obtained collateral or other security to support its financial derivatives.

Vermilion's cash deposited in financial institutions and guaranteed investment certificates are also subject to counterparty credit risk. Vermilion mitigates this risk by transacting with financial institutions with high third party credit ratings.

Liquidity risk:

Liquidity risk is the risk that Vermilion will encounter difficulty in meeting obligations associated with its financial liabilities. Vermilion does not consider this to be a significant risk as its financial position and available committed borrowing facility provide significant financial flexibility and allow Vermilion to meet its obligations as they come due.

The following table summarizes Vermilion's undiscounted non-derivative financial liabilities and their contractual maturities:

($M)	1 month	1 month to 3 months	3 months to 1 year	1 year to 5 years
December 31, 2018	167,491	306,927	10,355	1,472,087
December 31, 2017	99,092	138,273	7,974	912,306

18. Related party disclosures

The compensation of directors and management is reviewed annually by the independent Governance and Human Resources Committee against industry practices for oil and gas companies of similar size and scope.

The following table summarizes the compensation of directors and other members of key management personnel during the years ended December 31, 2018 and 2017:

	Year Ended	
($M)	Dec 31, 2018	Dec 31, 2017
Short-term benefits	**6,018**	5,183
Share-based payments	**16,309**	20,135
	22,327	25,318
Number of individuals included in the above amounts	**18**	20

During the year ended December 31, 2018, Vermilion recorded $0.2 million of office rent recoveries (2017 - $0.2 million) relating to an office sub-lease to a company whose Managing Director is also a member of Vermilion's Board of Directors. This related party transaction is provided in the normal course of business under the same commercial terms and conditions as transactions with unrelated companies and is recorded at the exchange amount.

19. Supplemental information

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

	Year Ended	
($M)	Dec 31, 2018	Dec 31, 2017
Changes in:		
Accounts receivable	**(94,562)**	(34,041)
Crude oil inventory	**(10,646)**	(2,577)
Prepaid expenses	**(4,896)**	(1,884)
Accounts payable and accrued liabilities	**230,567**	37,527
Income taxes payable	**(1,651)**	2,842
Working capital assumed from acquisitions	**(58,841)**	—
Initial recognition of IFRS 16 liability	**(10,483)**	—
Foreign exchange	**(873)**	(795)
Changes in non-cash working capital	**48,615**	1,072
Changes in non-cash operating working capital	**(6,876)**	665
Changes in non-cash investing working capital	**55,491**	407
Changes in non-cash working capital	**48,615**	1,072

Cash and cash equivalents was comprised of the following:

	As at	
($M)	Dec 31, 2018	Dec 31, 2017
Cash on deposit with financial institutions	**26,604**	46,229
Guaranteed investment certificates	**205**	332
Cash and cash equivalents	**26,809**	46,561

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

($M)	Year Ended 2018	2017
Operating expense	**66,095**	48,823
General and administration expense	**42,496**	36,708
Wages and benefits	**108,591**	85,531

The following tables summarize Vermilion's outstanding risk management positions as at December 31, 2018:

Crude Oil	Period	Exercise date [1]	Currency	Bought Put Volume (bbl/d)	Weighted Average Bought Put Price / bbl	Sold Call Volume (bbl/d)	Weighted Average Sold Call Price / bbl	Sold Put Volume (bbl/d)	Weighted Average Sold Put Price / bbl	Swap Volume (bbl/d)	Weighted Average Swap Price / bbl
Dated Brent											
3-Way Collar	Sep 2018 - Jun 2019		CAD	2,500	91.20	2,500	98.63	2,500	76.00	—	—
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,350	91.76
3-Way Collar	Aug 2018 - Jun 2019		USD	500	66.92	500	80.00	500	55.00	—	—
3-Way Collar	Jan 2019 - Dec 2019		USD	500	70.00	500	80.00	500	60.00	—	—
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	—	750	61.33
Swap	Jul 2018 - Jun 2019		USD	—	—	—	—	—	—	1,500	68.52
Swap	Jan 2019 - Dec 2019		USD	—	—	—	—	—	—	2,250	73.17
WTI											
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	—	1,050	81.41
3-Way Collar	Jan 2019 - Dec 2019		USD	250	70.00	250	80.25	250	60.00	—	—
Swap	Apr 2018 -		USD	—	—	—	—	—	—	250	54.00

Mar 2019

North American Gas	Period	Exercise date (1)	Currency	Bought Put Volume (mcf/d)	Weighted Average Bought Put Price / mcf	Sold Call Volume (mcf/d)	Weighted Average Sold Call Price / mcf	Sold Put Volume (mcf/d)	Weighted Average Sold Put Price /mcf	Swap Volume (mcf/d)	Weight Average Sw Price / m
AECO											
Swap	Dec 2018 - Mar 2019		CAD	—	—	—	—	—	—	2,500	2.4
AECO Basis (AECO less NYMEX Henry Hub)											
Swap	Jan 2019 - Jun 2020		USD	—	—	—	—	—	—	2,500	(0.9
AECO Basis (AECO less Chicago NGI)											
Swap	Nov 2018 - Mar 2019		USD	—	—	—	—	—	—	5,000	(1.4
NYMEX Henry Hub											
Swap	Jan 2019 - Mar 2019		USD	—	—	—	—	—	—	5,000	4.0
Chicago NGI											
Swap	Dec 2018 - Mar 2019		USD	—	—	—	—	—	—	5,000	4.4
SOCAL Border											
Swap (2)	Jan 2019		USD	—	—	—	—	—	—	10,000	5.5
Swap (2)	Feb 2019		USD	—	—	—	—	—	—	10,000	4.3
Swap (2)	Mar 2019		USD	—	—	—	—	—	—	10,000	3.3

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

(2) These swaps hedge a physical sales agreement to sell Alberta natural gas production at SOCAL Border pricing less a fixed differential.

European Gas	Period	Exercise date [1]	Currency	Bought Put Volume (mcf/d)	Weighted Average Bought Put Price / mcf	Sold Call Volume (mcf/d)	Weighted Average Sold Call Price / mcf	Sold Put Volume (mcf/d)	Weighted Average Sold Put Price /mcf	Swap Volume (mcf/d)	Weighted Average Swap Price / mcf
NBP											
3-Way Collar	Jan 2019 - Dec 2019		EUR	17,197	4.97	17,197	5.65	17,197	3.79	—	—
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	3.74	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	19,654	5.10	19,654	5.92	19,654	4.01	—	—
Collar	Oct 2018 - Mar 2019		EUR	3,685	6.40	2,457	7.62	—	—	—	—
Call	Oct 2018 - Mar 2019		EUR	—	—	12,327	6.28	—	—	—	—
Swap	Oct 2018 - Mar 2019		EUR	—	—	—	—	—	—	4,913	7.92
Swaption	Jul 2019 - Jun 2021	June 28, 2019	EUR	—	—	—	—	—	—	9,827	5.64
Swaption	Oct 2019 - Mar 2020	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
Swaption	Oct 2020 - Mar 2021	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
Swaption	Oct 2021 - Mar 2022	June 28, 2019	EUR	—	—	—	—	—	—	7,370	5.86
NBP Basis (NBP less NYMEX HH)											
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	—	—	—
TTF											
3-Way Collar	Oct 2017 - Dec 2019		EUR	7,370	4.59	7,370	5.42	7,370	2.93	—	—
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	3.13	—	—
3-Way Collar	Jan 2019 - Dec 2019		EUR	12,284	5.05	12,284	5.72	12,284	3.69	—	—
3-Way Collar	Jan 2020 - Dec 2020		EUR	7,370	5.37	7,370	6.25	7,370	3.81	—	—
Swap	Oct 2017 -		EUR	—	—	—	—	—	—	7,370	4.87

	Dec 2019									
Swap	Jan 2018 - Dec 2019	EUR	—	—	—	—	—	—	1,228	5.00
Swap	Jul 2018 - Dec 2019	EUR	—	—	—	—	—	—	4,913	4.98
Swap	Jan 2019 - Dec 2019	EUR	—	—	—	—	—	—	2,457	4.92

Cross Currency Interest Rate		Receive Notional Amount (USD)	Rate (LIBOR +)	Pay Notional Amount (CAD)	Rate (CDOR +)
Swap	Jan 2019	1,018,563,000	1.70%	1,354,900,000	1.02%

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

DIRECTORS

Lorenzo Donadeo [1]
Calgary, Alberta

Larry J. Macdonald [2, 4, 6, 8]
Chairman & CEO, Point Energy Ltd.
Calgary, Alberta

Carin Knickel [6, 8, 12]
Golden, Colorado

Stephen P. Larke [4, 6, 12]
Calgary, Alberta

Loren M. Leiker [10]
McKinney, Texas

Timothy R. Marchant [7, 10, 11]
Calgary, Alberta

Anthony Marino
Calgary, Alberta

Robert Michaleski [4, 5]
Calgary, Alberta

William Roby [8, 9, 12]
Katy, Texas

Catherine L. Williams [3, 6]
Calgary, Alberta

1 Chairman of the Board
2 Lead Director
3 Audit Committee Chair (Independent)
4 Audit Committee Member
5 Governance and Human Resources Committee Chair __(Independent)
6 Governance and Human Resources Committee Member
7 Health, Safety and Environment Committee Chair __(Independent)
8 Health, Safety and Environment Committee Member
9 Independent Reserves Committee Chair (Independent)
10 Independent Reserves Committee Member
11 Sustainability Committee Chair (Independent)

OFFICERS AND KEY PERSONNEL
CANADA

Anthony Marino
President & Chief Executive Officer

Lars Glemser
Vice President & Chief Financial Officer

Mona Jasinski
Executive Vice President, People and Culture

Michael Kaluza
Executive Vice President & Chief Operating Officer

Dion Hatcher
Vice President Canada Business Unit

Terry Hergott
Vice President Marketing

Jenson Tan
Vice President Business Development

Daniel Goulet
Director Corporate HSE

Jeremy Kalanuk
Director Operations Accounting

Bryce Kremnica
Director Field Operations - Canada Business Unit

Kyle Preston
Director Investor Relations

Robert (Bob) J. Engbloom
Corporate Secretary

UNITED STATES
Scott Seatter
Managing Director - U.S. Business Unit

Timothy R. Morris
Director U.S. Business Development - U.S.
Business Unit

EUROPE
Gerard Schut
Vice President European Operations

Sylvain Nothhelfer

AUDITORS

Deloitte LLP
Calgary, Alberta

BANKERS

The Toronto-Dominion Bank

Bank of Montreal

Canadian Imperial Bank of Commerce

Export Development Canada

National Bank of Canada

Royal Bank of Canada

The Bank of Nova Scotia

Wells Fargo Bank N.A., Canadian Branch

HSBC Bank Canada

Bank of America N.A., Canada Branch

Citibank N.A., Canadian Branch - Citibank Canada

JPMorgan Chase Bank, N.A., Toronto Branch

La Caisse Centrale Desjardins du Québec

Alberta Treasury Branches

Canadian Western Bank

Goldman Sachs Lending Partners LLC

Barclays Bank PLC

EVALUATION ENGINEERS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Norton Rose Fulbright Canada LLP
Calgary, Alberta

TRANSFER AGENT

Managing Director - France Business Unit

Sven Tummers
Managing Director - Netherlands Business Unit

Bill Liutkus
Managing Director - Germany Business Unit

Darcy Kerwin
Managing Director - Ireland Business Unit

Bryan Sralla
Managing Director - Central & Eastern Europe Business Unit

AUSTRALIA
Bruce D. Lake
Managing Director - Australia Business Unit

[12] Sustainability Committee Member

Computershare Trust Company of Canada

STOCK EXCHANGE LISTINGS

The Toronto Stock Exchange ("VET")
The New York Stock Exchange ("VET")

INVESTOR RELATIONS
Kyle Preston
Director Investor Relations
403-476-8431 TEL
403-476-8100 FAX
1-866-895-8101 IR TOLL FREE
investor_relations@vermilionenergy.com

EXHIBIT 99.4

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

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

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use of our reports dated February 27, 2019 relating to the consolidated financial statements of Vermilion Energy Inc. and subsidiaries (the "Company") and the effectiveness of the Company's internal control over financial reporting appearing in this Annual Report on Form 40-F of Vermilion Energy Inc. for the year ended December 31, 2018.

/s/ Deloitte LLP
Chartered Professional Accountants
Calgary, Canada
February 27, 2019

EXHIBIT 99.5

CONSENT OF GLJ PETROLEUM CONSULTANTS LTD.

Dear Sirs:

We hereby consent to the use of and reference to our name and our reports, and the inclusion of information derived from our reports, evaluating Vermilion Energy Inc.'s petroleum and natural gas reserves as at December 31, 2018, in this Annual Report on Form 40-F of Vermilion Energy Inc.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

"Originally Signed By"

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

Calgary, Alberta
February 7, 2019

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

EXHIBIT 99.6

VERMILION ENERGY INC.
CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER

I, Anthony Marino, President and Chief Executive Officer, certify that:

1. I have reviewed this annual report on Form 40-F of Vermilion Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

    d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 27, 2019

/s/ Anthony Marino
[Signature]

Anthony Marino, President and Chief Executive Officer

EXHIBIT 99.7

VERMILION ENERGY INC.
CERTIFICATION OF THE CHIEF FINANCIAL OFFICER

I, Lars Glemser, Vice President and Chief Financial Officer, certify that:

1. I have reviewed this annual report on Form 40-F of Vermilion Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation;

    d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 27, 2019

/s/ Lars Glemser
[Signature]

Lars Glemser, Vice President and Chief Financial Officer

Document And Entity Information	12 Months Ended Dec. 31, 2018 shares
Document Information [Line Items]	
Document Type	40-F
Amendment Flag	false
Entity Emerging Growth Company	false
Document Period End Date	Dec. 31, 2018
Document Fiscal Year Focus	2018
Document Fiscal Period Focus	FY
Entity Registrant Name	VERMILION ENERGY INC.
Entity Central Index Key	0001293135
Current Fiscal Year End Date	--12-31
Entity Current Reporting Status	Yes
Trading Symbol	VET
Entity Common Stock, Shares Outstanding	0

Consolidated Balance Sheet - CAD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017
Current		
Cash and cash equivalents	$ 26,809	$ 46,561
Accounts receivable	260,322	165,760
Crude oil inventory	27,751	17,105
Derivative instruments	95,667	17,988
Prepaid expenses	19,328	14,432
Total current assets	429,877	261,846
Derivative instruments	1,215	2,552
Deferred taxes	219,411	80,324
Exploration and evaluation assets	303,295	292,278
Capital assets	5,316,873	3,337,965
Total assets	6,270,671	3,974,965
Current		
Accounts payable and accrued liabilities	449,651	219,084
Dividends payable	35,122	26,256
Derivative instruments	41,016	78,905
Income taxes payable	37,410	39,061
Total current liabilities	563,199	363,306
Derivative instruments	17,527	12,348
Long-term debt	1,796,207	1,270,330
Lease obligations	108,189	15,807
Asset retirement obligations	650,164	517,180
Deferred taxes	318,134	253,108
Total liabilities	3,453,420	2,432,079
Shareholders' equity		
Shareholders' capital	4,008,828	2,650,706
Contributed surplus	78,478	84,354
Accumulated other comprehensive income	118,182	71,829
Deficit	(1,388,237)	(1,264,003)
Total shareholders' equity	2,817,251	1,542,886
Total liabilities and shareholders' equity	$ 6,270,671	$ 3,974,965

Consolidated Statements of Net Earnings and Comprehensive Income - CAD ($) shares in Thousands, $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Revenue		
Petroleum and natural gas sales	$ 1,678,117	$ 1,098,838
Royalties	(152,167)	(74,476)
Petroleum and natural gas revenue	1,525,950	1,024,362
Expenses		
Operating	357,014	242,267
Transportation	51,887	43,448
Equity based compensation	60,746	61,579
Loss (gain) on derivative instruments	1,932	(3,659)
Interest expense	72,759	57,313
General and administration	51,929	54,373
Foreign exchange loss (gain)	63,000	(74,058)
Other income	(82)	(37)
Accretion	31,219	26,971
Depletion and depreciation	609,056	491,683
Gain on business combinations	(128,208)	0
Expenses, by nature	1,171,252	899,880
Earnings before income taxes	354,698	124,482
Taxes		
Deferred	39,471	30,117
Current	43,577	32,107
Tax expense (income), continuing operations	83,048	62,224
Net earnings	271,650	62,258
Other comprehensive income		
Currency translation adjustments	46,353	41,490
Comprehensive income	$ 318,003	$ 103,748
Net earnings per share		
Basic	$ 1.93	$ 0.52
Diluted	$ 1.91	$ 0.51
Weighted average shares outstanding ('000s)		
Basic	140,619	120,582
Diluted	142,335	122,408

Consolidated Statements of Cash Flows - CAD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Operating		
Net earnings	$ 271,650	$ 62,258
Adjustments:		
Accretion	31,219	26,971
Depletion and depreciation	609,056	491,683
Gain on business combinations	(128,208)	0
Unrealized (gain) loss on derivative instruments	(109,326)	1,062
Equity based compensation	60,746	61,579
Unrealized foreign exchange loss (gain)	63,243	(71,742)
Unrealized other expense	801	637
Deferred taxes	39,471	30,117
Asset retirement obligations settled	(15,765)	(9,334)
Changes in non-cash operating working capital	(6,876)	665
Cash flows from operating activities	816,011	593,896
Investing		
Drilling and development	(503,842)	(290,593)
Exploration and evaluation	(14,372)	(29,856)
Acquisitions	(276,308)	(27,637)
Changes in non-cash investing working capital	55,491	407
Cash flows used in investing activities	(739,031)	(347,679)
Financing		
Borrowings (repayments) on the revolving credit facility	251,155	(450,646)
Issuance of senior unsecured notes	0	391,906
Payments on lease obligations	(18,884)	(4,874)
Cash dividends	(330,194)	(200,074)
Cash flows used in financing activities	(97,923)	(263,688)
Foreign exchange gain on cash held in foreign currencies	1,191	1,257
Net change in cash and cash equivalents	(19,752)	(16,214)
Cash and cash equivalents, beginning of year	46,561	62,775
Cash and cash equivalents, end of year	26,809	46,561
Supplementary information for cash flows from operating activities		
Interest paid	70,049	49,721
Income taxes paid	$ 45,228	$ 29,265

Consolidated Statements of Changes in Shareholders' Equity - CAD ($) $ in Thousands	Total	Issued capital [member]	Share premium [member]	Retained Earnings [Member]
Balance, beginning of year at Dec. 31, 2016	$ 2,452,722			
Shareholders' capital				
Shares issued for acquisition	0			
Shares issued for the Dividend Reinvestment Plan	110,493			
Vesting of equity based awards		$ 69,743	$ (69,743)	
Equity based compensation		9,270	52,309	
Share-settled dividends on vested equity based awards		8,478		$ (8,478)
Balance, end of year at Dec. 31, 2017	2,650,706			
Balance, beginning of year at Dec. 31, 2016	101,788			
Contributed surplus				
Equity based compensation		9,270	52,309	
Vesting of equity based awards		69,743	(69,743)	
Balance, end of year at Dec. 31, 2017	84,354			
Balance, beginning of year at Dec. 31, 2016	30,339			
Accumulated other comprehensive income				
Currency translation adjustments	41,490			
Balance, end of year at Dec. 31, 2017	71,829			
Balance, beginning of year at Dec. 31, 2016	(1,006,386)			
Deficit				
Net earnings	62,258			
Dividends declared	(311,397)			
Share-settled dividends on vested equity based awards		8,478		(8,478)
Balance, end of year at Dec. 31, 2017	(1,264,003)			
Deficit				
TOTAL SHAREHOLDERS' EQUITY	1,542,886			
Shares issued for acquisition	1,234,676			
Shares issued for the Dividend Reinvestment Plan	49,051			
Vesting of equity based awards		54,057	(54,057)	
Equity based compensation		12,565	48,181	
Share-settled dividends on vested equity based awards		7,773		(7,773)
Balance, end of year at Dec. 31, 2018	4,008,828			

Contributed surplus				
Equity based compensation		12,565	48,181	
Vesting of equity based awards		54,057	$ (54,057)	
Balance, end of year at Dec. 31, 2018	78,478			
Accumulated other comprehensive income				
Currency translation adjustments	46,353			
Balance, end of year at Dec. 31, 2018	118,182			
Deficit				
Net earnings	271,650			
Dividends declared	(388,111)			
Share-settled dividends on vested equity based awards		$ 7,773		$ (7,773)
Balance, end of year at Dec. 31, 2018	(1,388,237)			
Deficit				
TOTAL SHAREHOLDERS' EQUITY	$ 2,817,251			

Basis of presentation	12 Months Ended Dec. 31, 2018
Disclosure of Basis Of Presentation [Abstract]	
Disclosure of basis of preparation of financial statements [text block]	**1. Basis of presentation** Vermilion Energy Inc. and its subsidiaries (the “Company” or “Vermilion”) are engaged in the business of petroleum and natural gas e acquisition, and production. Vermilion was incorporated in Canada and the Company’s registered office and principal place of business is located at 3500, 520, 3 Alberta, Canada. These consolidated financial statements were approved and authorized for issuance by Vermilion’s Board of Directors on February 2

Significant accounting policies	12 Months Ended Dec. 31, 2018
Disclosure Of Significant Accounting Policies [Abstract]	
Disclosure of significant accounting policies [text block]	

2. Significant accounting policies

Accounting framework
The consolidated financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as iss
Accounting Standards Board ("IASB").

Principles of consolidation
The consolidated financial statements include the accounts of Vermilion Energy Inc. and its subsidiaries. Vermilion's subsidiaries
of the jurisdictions that Vermilion operates as described in Note 4 including: Canada, France, Netherlands, Germany, Ireland (thro
Cayman Islands incorporated company), Australia, the United States, Hungary, Slovakia, and Croatia. Vermilion Energy Inc. dire
holding companies owns all of the voting securities of each material subsidiary. Transactions between Vermilion Energy Inc. and its
eliminated.

Vermilion accounts for joint operations by recognizing the Company's share of assets, liabilities, income, and expenses.

Exploration and evaluation assets
Vermilion classifies costs as exploration and evaluation ("E&E") assets when they relate to exploring and evaluating an area for whi
license or right to explore and extract resources. E&E costs may include: geological and geophysical costs; land and license acquis
the drilling, completion, and testing of exploration wells.

E&E costs are reclassified to capital assets if the technical feasibility and commercial viability of the area can be determined. E&E
impairment prior to any reclassification. The technical feasibility and commercial viability of extracting the reserves is considered t
proved and probable reserves are identified.

Costs incurred prior to the acquisition of the legal rights to explore an area are expensed as incurred. If reserves are not found
or the area is abandoned, the related E&E costs are depreciated over a period not greater than five years. If an exploration lice
commencement of exploration activities, the cost of the exploration license is written off through depreciation in the year of expiration

Capital assets
Vermilion recognizes capital assets at cost less accumulated depletion, depreciation and impairment losses. Costs include directly a
for the drilling, completion, and tie-in of wells and the construction of production and processing facilities.

When components of capital assets are replaced, disposed of, or no longer in use, they are derecognized. Gains and losses on disp
determined by comparing the proceeds of disposal compared to the carrying amount.

Depletion and depreciation
Capital assets are grouped into depletion units, which are groups of assets within a specific production area that have similar econo
represent the lowest level of disaggregation for which costs are accumulated for the purposes of calculating depletion and depreciati

The net carrying value of each depletion unit is depleted using the unit of production method by reference to the ratio of production
proved and probable reserves, taking into account the future development costs necessary to bring the applicable reserves into proc

For the purposes of the depletion calculations, oil and gas reserves are converted to a common unit of measure on the basis of the
based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent.

Impairment of capital assets and exploration and evaluation assets
Depletion units are aggregated into cash generating units ("CGUs") for impairment testing. CGUs are the lowest level for which th
inflows that are largely independent of cash inflows of other groups of assets. CGUs are reviewed for indicators of potential impairme

E&E assets are tested for impairment when reclassified to capital assets or when indicators of potential impairment are identified. E
for indicators of potential impairment at each reporting date. If indicators of potential impairment are identified, E&E assets are teste
of the CGU attributable to the jurisdiction in which the exploration area resides.

If an indicator of potential impairment exists, the CGU's carrying value is compared to its recoverable amount. A CGU's recoverable
its fair value less costs of disposal and its value-in-use. If the carrying amount of a CGU exceeds its recoverable amount, an impairm
reduce the carrying value of the CGU to its recoverable amount.

If an impairment loss has been recognized in a prior period, an assessment is performed at each reporting date to determine if
the circumstances which led to the impairment loss have reversed. If the change in circumstances results in the recoverable amou
carrying value after the impairment loss, then the impairment loss (net of depletion that would otherwise have been recorded) is reve

Lease obligations and right-of-use assets
A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exc
At the lease commencement date, a lease obligation is recognized at the present value of future lease payments, typically using th
borrowing rate. A corresponding right-of-use asset is recognized at the amount of the lease obligation, adjusted for lease incentives
costs. Vermilion does not recognize leases for short-term leases with a lease term of 12 months or less, or leases for low-value asse

Payments are applied against the lease obligation and interest expense is recognized on the lease obligations using the effecti
Depreciation is recognized on the right-of-use asset over the lease term.

Cash and cash equivalents
Cash and cash equivalents include cash on deposit with financial institutions and guaranteed investment certificates.

Crude oil inventory
Crude oil inventory is valued at the lower of cost or net realizable value. The cost of crude oil inventory produced includes related ope
and depletion determined on a weighted-average basis.

Asset retirement obligations
Vermilion recognizes a provision for asset retirement obligations when an event occurs giving rise to an obligation of uncertain
retirement obligations are recognized on the consolidated balance sheet as a long-term liability with a corresponding increase to E&

Asset retirement obligations reflect the present value of estimated future settlement costs. The discount rate used to calculate the p
the jurisdiction the obligation relates to and is reflective of current market assessment of the time value of money and risks specific
not been reflected in the cash flow estimates.

Asset retirement obligations are remeasured at each reporting period to reflect changes in market rates and estimated future
retirement obligations are increased each reporting period to reflect the passage of time with a corresponding charge to accretion ex

Revenue recognition
Revenue associated with the sale of crude oil and condensate, natural gas, and natural gas liquids is measured based on the c
contracts with customers.

Revenue from contracts with customers is recognized when or as Vermilion satisfies a performance obligation by transferring
condensate, natural gas, or natural gas liquids to a customer at contractually specified transfer points. This transfer coincides with titl
and the customer taking physical possession of the commodity. Vermilion principally satisfies its performance obligations at a point
of revenue recognized relating to performance obligations satisfied over time are not significant.

Vermilion invoices customers for delivered products monthly and payment occurs shortly thereafter. Vermilion does not have any co
between the transfer of control of the commodity to the customer and payment by the customer exceeds one year. As a result, Ver
revenue transactions to reflect significant financing components.

Financial instruments
On initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods depends on the clas
instrument as described below:

- Fair value through profit or loss: Financial instruments under this classification include cash and cash equivalents and deriva
- Amortized cost: Financial instruments under this classification include accounts receivable, accounts payable and accr
payable, lease obligations, and long-term debt.

Accounts receivable are measured net of a loss allowance equal to the lifetime expected credit loss.

Equity based compensation
Equity based compensation expense results from equity-settled awards issued under Vermilion's long-term share-based compensa
grant date fair value of Vermilion common shares issued under the Company's bonus and employee share savings plans.

Vermilion's long-term share-based compensation plans consist of the Vermilion Incentive Plan ("VIP") and a security-based compensa
Year Compensation Arrangement"). Equity-settled awards issued under the VIP vest over a period of one to three years while a
Five-Year Compensation Arrangement vest in the fifth year following the grant date. Awards under both plans are adjusted upon v
factor determined by the Company's Board of Directors. Equity based compensation expense for both plans is recognized over t
corresponding adjustment to contributed surplus. The expense recognized is based on the grant date fair value of the awards, an est
factor that will be achieved, and an estimate of forfeiture rates based on historical vesting data. Dividends notionally accrue to the a
in the determination of grant date fair values. Upon vesting, the amount recognized in contributed surplus is reclassified to sharehol

The grant date fair value of the equity-settled awards issued under the VIP and the Five-Year Compensation Arrangement and th
Vermilion common shares issued under the Company's bonus and employee share savings plans are determined as the closing pric
shares on the Toronto Stock Exchange on the grant date.

Per share amounts
Basic net earnings per share is calculated by dividing net earnings by the weighted-average number of shares outstanding during th

Diluted net earnings per share is calculated by dividing net earnings by the diluted weighted-average number of shares outstandin
diluted weighted-average number of shares outstanding is the sum of the basic weighted-average number of shares outstanding an
reduces diluted net earnings per share) the number of shares issuable for equity-settled awards determined using the treasury sto
stock method assumes that the unrecognized equity based compensation expense are deemed proceeds used to repurchase Ver
the average market price during the period.

Foreign currency translation
Vermilion Energy Inc.'s functional and presentation currency is the Canadian dollar. Vermilion has subsidiaries that transact and o
than Canada and have functional currencies other than the Canadian dollar.

Foreign currency translation includes the translation of foreign currency transactions and the translation of foreign operations.

Foreign currency transaction translation occur when translating transactions and balances in foreign currencies to the applicab
Vermilion Energy Inc. and its subsidiaries. Gains and losses from foreign currency transactions are recorded as foreign exchange
currency transaction translation occurs as follows:

- Income and expenses are translated at the prevailing rates on the date of the transaction
- Non-monetary assets or liabilities are carried at the prevailing rates on the date of the transaction
- Monetary items, including intercompany loans that are not deemed to represent net investments in a foreign subsidiary, are translated a balance sheet date

Foreign operation translation occurs when translating the financial statements of non-Canadian functional currency subsidiaries
and when translating intercompany loans that are deemed to represent net investments in a foreign subsidiary. Gains and losse
translations are recorded as currency translation adjustments. Foreign operation translations occur as follows:

- Income and expenses are translated at the average exchange rates for the period
- Assets and liabilities are translated at the prevailing rates on the balance sheet date.

Income taxes

Deferred tax assets and liabilities are calculated using the balance sheet method. Deferred tax assets and liabilities are recognized
of any temporary differences between the amounts recognized on Vermilion's consolidated balance sheet and the respective tax ba
enacted or substantively enacted tax rates that are expected to be in effect when the temporary differences are expected to revers
in tax rates on deferred taxes is recognized in the period the related legislation is substantively enacted.

Deferred tax assets are recognized to the extent that it is probable that future taxable profits will be available against which t
differences can be used. Deferred tax assets are reviewed at each reporting date and are reduced to the extent it is no longer prol
benefit will be realized.

Business combinations

Acquisitions of corporations or groups of assets are accounted for as business combinations using the acquisition method if the a
a business. Under the acquisition method, assets acquired and liabilities assumed in a business combination (with the exceptio
and liabilities) are measured at their fair value. Deferred tax assets or liabilities arising from the assets acquired and liabilities as
accordance with the policies described in "Income taxes" above.

If applicable, the excess or deficiency of net assets acquired compared to consideration paid is recognized as a gain on business c
on the consolidated balance sheet. Acquisition-related costs incurred to effect a business combination are expensed in the period in

Segmented information

Vermilion has a decentralized business unit structure designed to manage assets in each country the Company operates in. Each
segments derives its revenues solely from the production and sale of petroleum and natural gas.

Vermilion's Corporate segment aggregates costs incurred at the Company's Corporate head office located in Calgary, Alberta, C
incurred relating to Vermilion's exploration and production activities in Hungary, Slovakia, and Croatia (Central and Eastern E
segments have similar economic characteristics as they do not currently generate material revenue.

Vermilion's chief operating decision maker regularly reviews fund flows from operations generated by each of Vermilion's operatin
from operations is a measure of profit or loss that provides the chief operating decision maker with the ability to assess the profi
segment and, correspondingly, the ability of each operating segment to fund its share of dividends, asset retirement obligations, and

Management judgments and estimation uncertainty

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, esti
that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these esti
management has made judgments, estimates, and assumptions are described below.

The measurement of the fair value of capital assets acquired in a business combination and the determination of the recoverable ar
units:

- Calculating the fair value of capital assets acquired in a business combination and the recoverable amount of cash generating of impairments or reversals of previous impairments if indicators of impairment or impairment reversal are identified) future commodity prices and estimated reserves and resources. Reserve and resource estimates are based on: engineerin commodity prices, expected future rates of production, and assumptions regarding the timing and amount of future expend estimates and assumptions can directly impact the calculated fair value of capital assets acquired (and thus the resulting goo combination) and the recoverable amount of a CGU (and thus the resulting impairment loss or recovery).
- In addition, the recoverable amount of a CGU is impacted by the composition of CGUs, which are subject to management' level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of ass Vermilion to determine CGUs vary by jurisdiction due to their unique operating and geographic conditions. In general, V following factors: geographic proximity of the assets within a group to one another, geographic proximity of the group of a assets, homogeneity of the production from the group of assets and the sharing of infrastructure used to process and/or transp in these judgments can directly impact the calculated recoverable amount of a CGU (and thus the resulting impairment loss

The measurement of the carrying value of asset retirement obligations on the balance sheet, including the fair value and subseque
retirement obligations assumed in a business combination:

- Asset retirement obligations are based on judgments regarding regulatory requirements, estimates of future costs, assur timing of expenditures, and estimates of the underlying risk inherent to the obligation. The carrying balance of asset re

accretion expense may differ due to changes in: laws and regulations, technology, the expected timing of expenditures
affecting the discount rate applied.

The recognition and measurement of deferred tax assets and liabilities:

- Tax interpretations, regulations, and legislation in the various jurisdictions in which Vermilion and its subsidiaries operate a interpretation. Changes in laws and interpretations can affect the timing of the reversal of temporary tax differences, the such differences reverse and Vermilion's ability to use tax losses and other tax pools in the future. The Company's incor to audit by taxation authorities in numerous jurisdictions and the results of such audits may increase or decrease the tax li of tax amounts recognized in the consolidated financial statements are based on management's assessment of the tax consideration of their technical merits, communications with tax authorities and management's view of the most likely outcor
- The extent to which deferred tax assets are recognized are based on estimates of future profitability. These estimates are b commodity prices and estimates of reserves. Judgments, estimates, and assumptions inherent in reserve estimates are des

The measurement of lease obligations and corresponding right-of-use assets:

- The measurement of lease obligations are subject to management's judgments of the applicable incremental borrowing rate term. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depletion and de differ due to changes in the market conditions and expected lease terms. Applicable incremental borrowing rates are ba economic environment, term, currency, and the underlying risk inherent to the asset. Lease terms are based on assumptio and extension terms that allow for operational flexibility based on future market conditions.

Changes in accounting pronouncements	12 Months Ended Dec. 31, 2018
Disclosure of Changes To Accounting Pronouncements [Abstract]	
Disclosure of expected impact of initial application of new standards or interpretations [text block]	

3. Changes in accounting pronouncements

IFRS 9 "Financial instruments"

On January 1, 2018, Vermilion adopted IFRS 9 *"Financial instruments"* as issued by the IASB. IFRS 9 includes a new classific approach for financial assets and a forward-looking 'expected credit loss' model. The adoption of IFRS 9 did not have a materi consolidated financial statements.

IFRS 15 "Revenue from contracts with customers"

On January 1, 2018, Vermilion adopted IFRS 15 "*Revenue from contracts with customers*". IFRS 15 establishes a comprehensive fr whether, how much, and when revenue from contracts with customers is recognized.

Vermilion adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of init recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was require 15.

IFRS 15 requires additional disclosure relating to the disaggregation of revenue - this additional disclosure is included in Note 4 (Seg

IFRS 16 "Leases"

Vermilion has elected to early adopt IFRS 16 effective January 1, 2018. IFRS 16 introduces a single lease accounting model for l right-of-use asset and lease liability to be recognized on the balance sheet for contracts that are, or contain, a lease.

Vermilion adopted IFRS 16 using the modified retrospective approach, whereby the cumulative effect of initially applying the stan a $97.1 million increase to right-of-use assets (included in "Capital assets") with a corresponding increase to lease obligations (th $86.1 million recorded in "lease obligations" and the current $11.0 million portion recorded in "Accounts payable and accrued liab assets recognized were measured at amounts equal to the lease obligations. The weighted average incremental borrowing rate use obligation at adoption was approximately 5.4%. The right-of-use assets and lease obligations recognized largely relate to the Compa Calgary and long-term leases for oil storage facilities in France.

The adoption of IFRS 16 included the following elections:

- Vermilion elected to retain the classification of contracts previously identified as leases under IAS 17 and IFRIC 4.
- Vermilion elected to use hindsight in determining lease term.
- Vermilion elected to not apply lease accounting to certain leases for which the lease term ends within 12 months of the date

As at December 31, 2017, Vermilion disclosed operating lease commitments of $40.2 million, which would have resulted in a l million when discounted at the weighted average incremental borrowing rate at adoption of IFRS 16 of 5.4%. The total current and recognized on January 1, 2018 of $97.1 million represented an increase of $62.8 million compared to the disclosed operating leas application of IFRS 16 in determining lease terms.

Segmented information

12 Months Ended Dec. 31, 2018

Disclosure Of Segmented Information [Abstract]

Disclosure of entity's operating segments [text block]

4. Segmented information

Vermilion has three major customers within the France, Netherlands, and Ireland operating segments that each comprise in exce consolidated revenues. Substantially all sales in the France, Netherlands, and Ireland operating segments for the years ended Dece were to one customer in each respective segment.

				Year Ended December 31, 2018			
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA
Total assets	3,060,291	918,398	277,348	284,063	709,585	263,739	407,323
Drilling and development	277,857	79,451	17,963	10,863	224	75,638	40,837
Exploration and evaluation	—	307	(480)	4,943	—	—	—
Crude oil and condensate sales	541,844	360,471	2,462	32,704	—	150,733	31,142
NGL sales	56,554	—	—	—	—	—	4,622
Natural gas sales	72,774	131	163,454	49,745	205,150	—	2,701
Royalties	(84,696)	(46,781)	(3,181)	(6,626)	—	—	(10,070)
Revenue from external customers	586,476	313,821	162,735	75,823	205,150	150,733	28,395
Transportation	(29,912)	(10,426)	—	(6,420)	(5,129)	—	—
Operating	(177,499)	(54,690)	(26,681)	(23,048)	(15,366)	(53,199)	(6,421)
General and administration	(6,057)	(14,170)	(1,947)	(7,401)	(8,386)	(4,918)	(6,306)
PRRT	—	—	—	—	—	(4,824)	—
Corporate income taxes	—	(15,084)	(16,561)	—	—	(6,595)	—
Interest expense	—	—	—	—	—	—	—
Realized loss on derivative instruments	—	—	—	—	—	—	—
Realized foreign exchange gain	—	—	—	—	—	—	—
Realized other income	—	—	—	—	—	—	—
Fund flows from operations	**373,008**	**219,451**	**117,546**	**38,954**	**176,269**	**81,197**	**15,668**

				Year Ended December 31, 2017			
($M)	Canada	France	Netherlands	Germany	Ireland	Australia	USA
Total assets	1,542,193	831,783	203,929	295,026	667,068	236,677	73,867
Drilling and development	148,667	71,087	15,107	6,165	551	29,942	19,074
Exploration and evaluation	—	2,294	16,468	3,366	—	—	—
Crude oil and condensate sales	209,560	268,102	1,864	23,554	—	154,391	14,605
NGL sales	37,809	—	—	—	—	—	456
Natural gas sales	83,534	1	106,196	45,142	153,330	—	294
Royalties	(33,258)	(28,565)	(1,722)	(6,655)	—	—	(4,276)
Revenue from external customers	297,645	239,538	106,338	62,041	153,330	154,391	11,079
Transportation	(17,368)	(14,627)	—	(6,207)	(5,205)	—	(41)
Operating	(80,444)	(51,002)	(21,212)	(20,176)	(17,596)	(50,139)	(1,698)
General and administration	(9,604)	(13,585)	(2,212)	(7,767)	(2,320)	(8,194)	(4,341)
PRRT	—	—	—	—	—	(19,819)	—
Corporate income taxes	—	(10,556)	3,331	—	—	(4,536)	—
Interest expense	—	—	—	—	—	—	—
Realized gain on derivative instruments	—	—	—	—	—	—	—
Realized foreign exchange gain	—	—	—	—	—	—	—
Realized other income	—	—	—	—	—	—	—
Fund flows from operations	**190,229**	**149,768**	**86,245**	**27,891**	**128,209**	**71,703**	**4,999**

Reconciliation of fund flows from operations to net earnings:

($M)	Year E Dec 31, 2018
Fund flows from operations	**838,652**
Accretion	**(31,219)**
Depletion and depreciation	**(609,056)**
Gain on business combinations	**128,208**
Unrealized gain (loss) on derivative instruments	**109,326**
Equity based compensation	**(60,746)**
Unrealized foreign exchange (loss) gain	**(63,243)**
Unrealized other expense	**(801)**
Deferred tax	**(39,471)**
Net earnings	**271,650**

Business combinations	12 Months Ended Dec. 31, 2018
Disclosure of detailed information about business combination [abstract]	
Disclosure of business combinations [text block]	

5. Business combinations

Private Producer in Southeast Saskatchewan and Southwest Manitoba

On February 15, 2018, Vermilion acquired all of the issued and outstanding common shares of a private producer with assets in south southwest Manitoba. The acquisition comprised of light oil producing fields near Vermilion's existing operations in southeast Saska complements Vermilion's existing southeast Saskatchewan operations and aligns with the Company's sustainable growth-and-incom was funded through Vermilion's revolving credit facility.

The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are detailed in

($M)
Cash paid to vendor
Total consideration

($M)	Alloc
Capital assets	
Deferred tax assets	
Acquired working capital	
Long-term debt	
Asset retirement obligations	
Net assets acquired	

For the year ended December 31, 2018, the acquisition contributed revenues of $18.7 million and net earnings of $6.7 million. Had on January 1, 2018, revenues would have increased by $2.9 million and net earnings would have increased by $1.0 million for the y 2018.

Spartan Energy Corp.

On May 28, 2018, Vermilion acquired all of the issued and outstanding common shares of Spartan Energy Corp., a publicly trad with light oil producing properties in southeast Saskatchewan as well as other areas in Saskatchewan, Alberta, and Manitoba. T Vermilion's position in southeast Saskatchewan and aligns with the Company's sustainable growth-and-income model.

Consideration consisted of the issuance of 27.9 million Vermilion common shares valued at approximately $1.2 billion (based Vermilion common share of $44.30 on the Toronto Stock Exchange on May 28, 2018). Acquisition-related costs of $1.3 million were in December 31, 2018.

The total consideration paid and the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are deta

($M)
Shares issued for acquisition
Total consideration

($M)	Alloc
Capital assets	
Deferred tax assets	
Long-term debt	
Asset retirement obligations	
Lease obligations	
Assumed working capital deficit	
Net assets acquired	

For the year ended December 31, 2018, the acquisition contributed revenues of $242.1 million and net earnings of $45.1 million. Had on January 1, 2018, revenues would have increased by $182.4 million and net earnings would have increased by $35.0 million for th 31, 2018.

Assets in Wyoming

In August 2018, Vermilion acquired oil and gas producing assets and mineral leasehold land from a private oil company for tot approximately $189 million. The assets are located in Campbell County, Wyoming in the Powder River Basin, approximately 65 Vermilion's existing operations. The acquired assets complement Vermilion's existing Powder River operations and align with the growth-and-income model. The acquisition was funded through Vermilion's revolving credit facility.

The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are detailed in

($M)
Cash paid to vendor
Total consideration

($M)	Alloc
Capital assets	
Deferred tax liability	
Asset retirement obligations	
Assumed working capital deficit	
Net assets acquired	
Gain on business combination	
Total net assets acquired, net of gain on business combination	

The gain on the business combination primarily resulted from the recognition of additional reserve value when the acquisition closed estimated value when Vermilion entered into the purchase and sale agreement and the acquisition price was determined.

For the year ended December 31, 2018, the acquisition contributed revenues of $11.6 million and net earnings of $0.3 million. Had on January 1, 2018, revenues would have increased by $11.1 million and net earnings would have decreased by $0.1 million for th 31, 2018.

Shell E&P Ireland Limited

In December 2018, Vermilion acquired all of the issued and outstanding common shares of Shell E&P Ireland Limited, along with an i interest in the Corrib Natural Gas Project ("Corrib") in Ireland from Nephin Energy Holdings Limited, a wholly owned subsidiary Investment Board. The acquisition increases Vermilion's total ownership in Corrib to 20% and aligns with the Company's sustai model. In addition to this transaction, Vermilion has assumed operatorship of Corrib.

The total consideration paid and the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are det

($M)	
Cash paid to vendor	
Cash acquired	
Contingent consideration	
Total consideration	

($M)	Alloc
Capital assets	
Deferred tax assets	
Assumed working capital deficit	
Lease obligations	
Asset retirement obligations	
Net assets acquired	
Gain on business combination	
Total net assets acquired, net of gain on business combination	

The fair value of the contingent consideration obligation is estimated to be approximately $0.3 million based on estimated futu estimated reserves. Maximum contingent payments are €5.8 million (approximately $9.1 million) through 2025.

The gain on the business combination primarily resulted from increases in working capital and the fair value of capital assets from sale agreement was entered into in July 2017 and when the acquisition closed in December 2018.

For the year ended December 31, 2018, the acquisition contributed revenues of $1.3 million and net earnings of $0.4 million. Had th January 1, 2018, revenues would have increased by $15.2 million and net earnings would have increased by $4.3 million for the y 2018.

Minor acquisitions

Vermilion completed a number of minor acquisitions during the year ended December 31, 2018 for total cash consideration of $56.0 million of capital assets, $28.6 million of exploration and evaluation assets, and $104.0 million of asset retirement obligations were r

Capital assets	12 Months Ended Dec. 31, 2018
Disclosure of detailed information about property, plant and equipment [abstract]	
Disclosure of property, plant and equipment [text block]	

6. Capital assets

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

($M)	2018
Balance at January 1	**3,337,965**
Acquisitions	**1,975,327**
Additions	**503,842**
Increase in right-of-use assets	**98,343**
Transfers from exploration and evaluation assets	**29,615**
Depletion and depreciation	**(605,994)**
Changes in asset retirement obligations	**(100,876)**
Foreign exchange	**78,651**
Balance at December 31	**5,316,873**
Cost	**9,202,604**
Accumulated depletion and depreciation	**(3,885,731)**
Carrying amount at December 31	**5,316,873**

The following table discloses the carrying balance and depreciation charge relating to right-of-use assets by class of underlying ass
ended December 31, 2018:

($M)	Depreciation
Office space	**9,119**
Gas processing facilities	**5,491**
Oil storage facilities	**2,728**
Vehicles and equipment	**2,020**
Total	**19,358**

2018 and 2017 impairment assessment

As at December 31, 2018 and 2017, Vermilion did not identify any indicators of impairment.

Exploration and evaluation assets	12 Months Ended Dec. 31, 2018
Disclosure Of Exploration And Evaluation Assets [Abstract]	
Disclosure of exploration and evaluation assets [text block]	**7. Exploration and evaluation assets** The following table reconciles the change in Vermilion's exploration and evaluation assets:

($M)	2018
Balance at January 1	**292,278**
Acquisitions	**28,572**
Additions	**14,372**
Changes in asset retirement obligations	**629**
Transfers to capital assets	**(29,615)**
Depreciation	**(5,942)**
Foreign exchange	**3,001**
Balance at December 31	**303,295**
Cost	**371,015**
Accumulated depreciation	**(67,720)**
Carrying amount at December 31	**303,295**

Asset retirement obligations	12 Months Ended Dec. 31, 2018
Disclosure Of Asset Retirement Obligations [Abstract]	
Disclosure of other provisions, contingent liabilities and contingent assets [text block]	**8. Asset retirement obligations**

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

($M)	2018
Balance at January 1	**517,180**
Additional obligations recognized	**211,580**
Changes in estimated abandonment timing and costs	**(98,158)**
Obligations settled	**(15,765)**
Accretion	**31,219**
Changes in discount rates	**(6,646)**
Foreign exchange	**10,754**
Balance at December 31	**650,164**

Vermilion has estimated the asset retirement obligations based on a total undiscounted future liability of $2.6 billion (2017 - $1.6 billi expected to be made between 2020 and 2078, with the majority of spending occurring between 2029 and 2036 ($0.6 billion), 2047 t 2063 and 2068 ($0.9 billion). Inflation rates used in determining the cash flow estimates were between 0.5% and 2.9% (2017 - be Vermilion calculated the present value of the obligations using a credit-adjusted risk-free rate, calculated using a credit spread of 4. to risk-free rates based on long-term, risk-free government bonds.

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

	Dec 31,
Canada	
France	
Netherlands	
Germany	
Ireland	
Australia	
USA	

A 0.5% increase/decrease in the discount rate applied to asset retirement obligations would decrease/increase asset retirement obli $55.0 million. A one-year increase/decrease in the expected timing of abandonment spend would decrease/increase asset r approximately $25.0 million.

Derivative instruments	12 Months Ended Dec. 31, 2018
Disclosure Of Derivative instruments [Abstract]	
Disclosure of derivative financial instruments [text block]	9. Derivative instruments

9. Derivative instruments

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

($M)	Year E Dec 31, 2018
Fair value of contracts, beginning of year	(70,713)
Reversal of opening contracts settled during the year	57,719
Assumed in acquisitions	(274)
Realized (loss) gain on contracts settled during the year	(111,258)
Unrealized gain (loss) during the year on contracts outstanding at the end of the year	51,607
Net receipt from counterparties on contract settlements during the year	111,258
Fair value of contracts, end of year	38,339
Comprised of:	
Current derivative asset	95,667
Current derivative liability	(41,016)
Non-current derivative asset	1,215
Non-current derivative liability	(17,527)
Fair value of contracts, end of year	38,339

The loss (gain) on derivative instruments for 2018 and 2017 were comprised of the following:

($M)	Year E Dec 31, 2018
Realized loss (gain) on contracts settled during the year	111,258
Reversal of opening contracts settled during the year	(57,719)
Unrealized (gain) loss on contracts outstanding at the end of the year	(51,607)
Loss (gain) on derivative instruments	1,932

Please refer to Note 19 (Supplemental information) for a listing of Vermilion's outstanding derivative instruments as at December 31,

Leases	12 Months Ended Dec. 31, 2018
Disclosure of leases [Abstract]	
Disclosure of leases [text block]	**10. Leases** Vermilion had the following future commitments associated with its lease obligations:

($M)	Dec 31, 2018
Less than 1 year	30,641
1 - 3 years	50,024
4 - 5 years	34,313
After 5 years	42,739
Total lease payments	157,717
Amounts representing interest	(24,583
Present value of net lease payments	133,134
Current portion of lease obligations	(24,945
Non-current portion of lease obligations	108,189

The significant increase in total lease payments as at December 31, 2018 compared to December 31, 2017 primarily relates to effective January 1, 2018 and lease obligations assumed on acquisitions. Please refer to Note 3 (Changes to accounting pronouncer combinations), and Note 6 (Capital assets) for additional information.

For the year ended December 31, 2018, interest expense of $7.2 million and total cash outflow of $28.0 million were recognized rela

Taxes	12 Months Ended Dec. 31, 2018
Disclosure Of Taxes [Abstract]	
Disclosure of income tax [text block]	**11. Taxes**

11. Taxes

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

($M)	As Dec 31, 2018
Deferred tax assets:	
Non-capital losses	487,398
Capital assets	(296,591)
Asset retirement obligations	38,429
Derivative contracts	(11,937)
Unrealized foreign exchange	(1,873)
Other	3,985
Deferred tax assets	219,411
Deferred tax liabilities:	
Capital assets	(319,553)
Non-capital losses	57,785
Asset retirement obligations	(51,031)
Unrealized foreign exchange	(10,715)
Derivative contracts	—
Other	5,380
Deferred tax liabilities	(318,134)

Income tax expense differs from the amount that would have been expected if the reported earnings had been subject only to the sta tax rate as follows:

($M)	Year Dec 31, 2018
Earnings before income taxes	354,698
Canadian corporate tax rate	27.0%
Expected tax expense	95,768
Increase (decrease) in taxes resulting from:	
Petroleum resource rent tax rate (PRRT) differential (1)	5,349
Foreign tax rate differentials (1), (2)	3,086
Equity based compensation expense	13,883
Amended returns and changes to estimated tax pools and tax positions	(873)
Statutory rate changes and the estimated reversal rates associated with temporary differences (3)	—
(Re-recognition) de-recognition of deferred tax assets	(26,931)
Adjustment for uncertain tax positions	8,080
Gain on business combinations	(28,812)
Other non-deductible items	13,498
Provision for income taxes	83,048

(1) In Australia, current taxes include both corporate income tax rates and PRRT. Corporate income tax rates were applied at a rat applied at a rate of 40%.

(2) The applicable tax rates for 2018 were: 34.4% in France, 50.0% in the Netherlands, 30.2% in Germany, 25.0% in Ireland, and 21

(3) On December 22, 2017, the Tax Cuts and Jobs Act was signed into law in the United States reducing the U.S. federal corpor 35% to 21%. On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 pr decrease of the French standard corporate income tax rate from 34.43% to 25.825% by 2022. On December 18, 2018, the Dut the 2019 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% to 20.5% by 2021, with the first reduction plan Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not exp impact to Vermilion taxes in the Netherlands.

At December 31, 2018, Vermilion had $2.6 billion (2017 - $2.0 billion) of unused tax losses of which $1.1 billion (2017 - $0.5 billi Canada segment and expire between 2025 and 2038 and $1.3 billion (2017 - $1.3 billion) relates to Vermilion's Ireland segment and over-year increase in unused tax losses in Vermilion's Canada segment was the result of tax losses acquired in the business combi 5.

At December 31, 2018, Vermilion re-recognized $90.6 million (2017 - de-recognized $145.6 million) of deductible temporary d aforementioned non-expiring tax loss pools in Ireland based on the Company's expected ability to fully utilize such losse price forecasts in effect as at December 31, 2018.

The aggregate amount of temporary differences associated with investments in subsidiaries for which deferred tax liabilities have n December 31, 2018 is approximately $0.5 billion (2017 – approximately $0.4 billion).

Long-term debt	12 Months Ended Dec. 31, 2018
Disclosure Of Long-Term Debt [Abstract]	
Disclosure of debt instruments [text block]	**12. Long-term debt**

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

($M)	As a Dec 31, 2018
Revolving credit facility	**1,392,206**
Senior unsecured notes	**404,001**
Long-term debt	**1,796,207**

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

($M)	2018
Balance at January 1	**1,270,330**
Borrowings (repayments) on the revolving credit facility	**251,155**
Issuance of senior unsecured notes	**—**
Assumed on acquisitions (1)	**188,496**
Amortization of transaction costs and prepaid interest	**2,286**
Foreign exchange	**83,940**
Balance at December 31	**1,796,207**

(1) Pursuant to the acquisitions described in Note 5 (Business Combinations), Vermilion assumed the credit facilities of the acquired companies and them following the respective acquisitions using proceeds from Vermilion's revolving credit facility.

Revolving credit facility

At December 31, 2018, Vermilion had in place a bank revolving credit facility maturing May 31, 2022 with the following terms:

($M)	As a Dec 31, 2018
Total facility amount	**1,800,000**
Amount drawn	**(1,392,206)**
Letters of credit outstanding	**(15,400)**
Unutilized capacity	**392,394**

The facility can be extended from time to time at the option of the lenders and upon notice from Vermilion. If no extension is gra amounts owing pursuant to the facility are due at the maturity date. The facility is secured by various fixed and floating charges ag Vermilion.

The facility bears interest at a rate applicable to demand loans plus applicable margins.

As at December 31, 2018, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As Dec 31, 2018
Consolidated total debt to consolidated EBITDA	4.0	**1.72**
Consolidated total senior debt to consolidated EBITDA	3.5	**1.34**
Consolidated total senior debt to total capitalization	55%	**30%**

The financial covenants include financial measures defined within the revolving credit facility agreement that are not defined under IF measures are defined by the revolving credit facility agreement as follows:

- Consolidated total debt: Includes all amounts classified as "Long-term debt" and "Lease obligations" (including the curren "Accounts payable and accrued liabilities" but excluding operating leases as defined under IAS 17) on the balance sheet.
- Consolidated total senior debt: Defined as consolidated total debt excluding unsecured and subordinated debt.
- Consolidated EBITDA: Defined as consolidated net earnings before interest, income taxes, depreciation, accretion and certa adjusted for the impact of the acquisition of a material subsidiary.
- Total capitalization: Includes all amounts classified as "Shareholders' equity" plus consolidated total debt as defined above.

As at December 31, 2018 and 2017, Vermilion was in compliance with the above covenants.

Senior unsecured notes

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

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

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

- Prior to March 15, 2020, Vermilion may redeem up to 35% of the original principal amount of the senior unsecured notes with the p offerings by the Company at a redemption price of 105.625% of the principal amount plus any accrued and unpaid interest to th date.
- Prior to March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at a price equal to 100% of the princ unsecured notes, plus an applicable premium and any accrued and unpaid interest.
- On or after March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth i any accrued and unpaid interest.

Year
2020
2021
2022
2023 and thereafter

Shareholders' capital	12 Months Ended Dec. 31, 2018
Disclosure of Shareholder's Capital [Abstract]	
Disclosure of share capital, reserves and other equity interest [text block]	**13. Shareholders' capital**

13. Shareholders' capital

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

Shareholders' Capital	2018 Shares ('000s)	2018 Amount ($M)	Sh ('0
Balance at January 1	**122,119**	**2,650,706**	118
Shares issued for acquisition	**27,883**	**1,234,676**	
Shares issued for the Dividend Reinvestment Plan	**1,179**	**49,051**	2
Vesting of equity based awards	**1,025**	**54,057**	1
Shares issued for equity based compensation	**314**	**12,565**	
Share-settled dividends on vested equity based awards	**184**	**7,773**	
Balance at December 31	**152,704**	**4,008,828**	122

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

Dividends are approved by the Board of Directors and are paid monthly. Dividends declared to shareholders for the year ended D $388.1 million or $2.72 per common share (2017 - $311.4 million or $2.58 per common share).

Subsequent to the end of year-end and prior to the consolidated financial statements being authorized for issue on February 27, 201 dividends of $70.3 million or $0.230 per share for each of January and February of 2019.

Capital disclosures	12 Months Ended Dec. 31, 2018
Disclosure Of Capital Disclosures [Abstract]	
Disclosure of objectives, policies and processes for managing capital [text block]	**14. Capital disclosures** Vermilion defines capital as net debt (long-term debt plus net working capital) and shareholders' capital. Vermilion excludes from its obligations secured by an offsetting asset, such as lease obligations. Vermilion monitors the ratio of net debt to fund flows from operations. As at December 31, 2018, our ratio of net debt to trailing fu is 2.30 (2017 - 2.28). Vermilion manages the ratio of net debt to fund flows from operations (refer to Note 4 - Segmented Inform expenditures, dividends, and asset retirement obligations with expected fund flows from operations. Vermilion intends for the ratio from operations to trend towards 1.5 over time. The following table calculates Vermilion's ratio of net debt to fund flows from operations:

($M except as indicated)	Year E Dec 31, 2018
Long-term debt	1,796,207
Current liabilities	563,199
Current assets	(429,877)
Net debt	**1,929,529**
Ratio of net debt to fund flows from operations	**2.30**

Equity based compensation	12 Months Ended Dec. 31, 2018

Disclosure Of Equity Based Compensation [Abstract]

Disclosure of share-based payment arrangements [text block]

15. Equity based compensation

The following table summarizes the number of awards outstanding under the VIP and the Five-Year Compensation Arrangement:

Number of Awards ('000s)	2018
Opening balance	1,685
Granted	932
Vested	(520)
Forfeited	(166)
Closing balance	**1,931**

For the year ended December 31, 2018, the awards granted had a weighted average fair value of $40.57 (2017 - $49.44). Equ expense is calculated based on the number of awards outstanding multiplied by the estimated performance factor that will be realiz 1.9; 2017 - 1.9) adjusted by an estimated annual forfeiture rate (2018 - 4.6%; 2017 - 4.4%). Equity based compensation expense of $4 during the year ended December 31, 2018 (2017 - $52.3 million) relating to the awards.

As at December 31, 2018, 36,845 awards included in the closing balance related to the Five-Year Compensation Arrangement.

Per share amounts	12 Months Ended Dec. 31, 2018
Disclosure Of Per Share Amounts [Abstract]	
Disclosure of earnings per share [text block]	**16. Per share amounts** Basic and diluted net earnings per share have been determined based on the following:

($M except per share amounts)	Year E Dec 31, 2018
Net earnings	**271,650**
Basic weighted average shares outstanding ('000s)	**140,619**
Dilutive impact of equity based compensation ('000s)	**1,716**
Diluted weighted average shares outstanding ('000s)	**142,335**
Basic earnings per share	**1.93**
Diluted earnings per share	**1.91**

Financial instruments	12 Months Ended Dec. 31, 2018
Disclosure of detailed information about financial instruments [abstract]	
Disclosure of financial instruments [text block]	

17. Financial instruments

Classification of financial instruments

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

($M)	As at Dec 31, 2018 Carrying value	Fair value	As a Carrying va
Fair value through profit or loss			
Cash and cash equivalents	**26,809**	**26,809**	46,5
Derivative assets	**96,882**	**96,882**	20,5
Derivative liabilities	**(58,543)**	**(58,543)**	(91,2
Amortized cost			
Accounts receivable	**260,322**	**260,322**	165,7
Accounts payable and accrued liabilities	**(449,651)**	**(449,651)**	(219,0
Dividends payable	**(35,122)**	**(35,122)**	(26,2
Long-term debt	**(1,796,207)**	**(1,781,809)**	(1,270,3

On January 1, 2018, Vermilion adopted IFRS 9 "Financial instruments". As a result, Vermilion's financial instruments were re-ca 9's new measurement categories. There were no changes in the carry amounts of financial instruments as a result of this re-categ "Financial instruments: recognition and measurement", Vermilion's financial instruments were classified as follows:

- Cash and cash equivalents and derivative assets were classified as held for trading. Held for trading financial instrum measured at fair value on the consolidated balance sheet with gains and losses recognized in net earnings.
- Accounts receivable were classified as loans and receivables while accounts payable and accrued liabilities, dividends pa and long-term debt were classified as other financial liabilities. Loans and receivables and other financial liabilities were su amortized cost on the consolidated balance sheet.

Fair value measurements are categorized into a fair value hierarchy based on the lowest level input that is significant to the fair value

- Level 1 inputs are determined by reference to unadjusted quoted prices in active markets for identical assets or liabilities. measurement of cash and cash equivalents and the senior unsecured notes are categorized as Level 1.
- Level 2 inputs are determined based on inputs other than unadjusted quoted prices that are observable, either directly or of Vermilion’s derivative assets and liabilities are determined using pricing models that incorporate future price forecasts (observable market transactions) and credit risk adjustments.
- Level 3 inputs are not based on observable market data. Vermilion does not have any financial instruments classified as Lev

There were no transfers between levels in the hierarchy in the years ended December 31, 2018 and 2017.

The carrying value of accounts receivable, accounts payable and accrued liabilities, and dividends payable are a reasonable approx due to the short maturity of these financial instruments. The carrying value of long-term debt outstanding on the revolving credit fa value due to the use of short-term borrowing instruments at market rates of interest.

Nature and Extent of Risks Associated with Financial Instruments

Vermilion is exposed to financial risks from its financial instruments. These financial risks include: market risk (includes commodity p and currency risk), credit risk, and liquidity risk.

Commodity price risk

Vermilion is exposed to commodity price risk on its derivative assets and liabilities which are used as part of the Company’s ris to mitigate the effects of changes in commodity prices on future cash flows. While transactions of this nature relate to future p production, Vermilion does not designate these derivative assets and liabilities as accounting hedges. As such, changes in commo value of derivative instruments and the corresponding gains or losses recognized on derivative instruments.

Currency risk

Vermilion is exposed to currency risk on its financial instruments denominated in foreign currencies. These financial instru cash equivalents, accounts receivables, accounts payables, lease obligations, long-term debt, derivative assets and derivative l instruments are primarily denominated in the US dollar and the Euro. Vermilion monitors its exposure to currency risk and reviews whe financial instruments is appropriate to manage potential fluctuations in foreign exchange rates.

Interest rate risk

Vermilion is exposed to interest rate risk on its revolving credit facility, which consists of short-term borrowing instruments that bea Thus, changes in interest rates could result in an increase or decrease in the amount paid by Vermilion to service this debt.

The following table summarizes the increase (positive values) or decrease (negative values) to net earnings before tax due to a Vermilion’s financial instruments as a result of a change in the relevant market risk variable. This analysis does not attempt to refle between the relevant risk variables.

($M)	Dec 31, 2018
Currency risk - Euro to Canadian dollar	

$0.01 increase in strength of the Canadian dollar against the Euro	**(2,205)**
$0.01 decrease in strength of the Canadian dollar against the Euro	**2,205**
Currency risk - US dollar to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the US $	**2,981**
$0.01 decrease in strength of the Canadian dollar against the US $	**(2,981)**
Commodity price risk - Crude oil	
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(18,421)**
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**17,351**
Commodity price risk - European natural gas	
€ 0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	**(36,508)**
€ 0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	**33,005**

Credit risk:
Vermilion is exposed to credit risk on accounts receivable and derivative assets in the event that customers, joint operation partners discharge their contractual obligations. As at December 31, 2018, Vermilion's maximum exposure to receivable credit risk was $357 2017 - $186.3 million) which is the value of accounts receivable and derivative assets on the balance sheet.

Vermilion's accounts receivable primarily relates to customers and joint operations partners in the petroleum and natural gas indu subject to normal industry payment terms and credit risks. Vermilion manages these risks by monitoring the creditworthiness of custor partners and, where appropriate, obtaining assurances such as parental guarantees and letters of credit. Vermilion determines the losses recognized on accounts receivable using a provision matrix. In preparing the provision matrix, the Company takes into acco experience based on the aging of accounts receivable, adjusted as necessary for current and future petroleum and natural gas changes in pricing may negatively impact the Company's customers and joint operations partners. The lifetime expected credit losse as at December 31, 2018 and 2017 is not material. As at the balance sheet date, approximately 0.7% (2017 - 0.7%) of the accounts outstanding for more than 90 days. Vermilion considers the balance of accounts receivable to be collectible.

Vermilion's derivative assets primarily relates to the fair value of financial instruments used as part of the Company's risk manager the effects of changes in commodity prices on future cash flows. Vermilion manages this risk by monitoring the creditworthiness of co primarily with counterparties that have investment grade third party credit ratings, and by limiting the concentration of financia counterparties. As a result, Vermilion has not obtained collateral or other security to support its financial derivatives.

Vermilion's cash deposited in financial institutions and guaranteed investment certificates are also subject to counterparty credit risk risk by transacting with financial institutions with high third party credit ratings.

Liquidity risk:
Liquidity risk is the risk that Vermilion will encounter difficulty in meeting obligations associated with its financial liabilities. Vermilion be a significant risk as its financial position and available committed borrowing facility provide significant financial flexibility and al obligations as they come due.

The following table summarizes Vermilion's undiscounted non-derivative financial liabilities and their contractual maturities:

($M)	1 month	1 month to 3 months	3 months to 1 year
December 31, 2018	167,491	306,927	10,355
December 31, 2017	99,092	138,273	7,974

Related party disclosures	12 Months Ended Dec. 31, 2018
Disclosure Of Related Party Disclosures [Abstract]	
Disclosure of related party [text block]	**18. Related party disclosures**

The compensation of directors and management is reviewed annually by the independent Governance and Human Resources Co practices for oil and gas companies of similar size and scope.

The following table summarizes the compensation of directors and other members of key management personnel during the years er and 2017:

($M)	Year E Dec 31, 2018
Short-term benefits	**6,018**
Share-based payments	**16,309**
	22,327
Number of individuals included in the above amounts	**18**

During the year ended December 31, 2018, Vermilion recorded $0.2 million of office rent recoveries (2017 - $0.2 million) relating a company whose Managing Director is also a member of Vermilion's Board of Directors. This related party transaction is providec business under the same commercial terms and conditions as transactions with unrelated companies and is recorded at the exchan

Supplemental information	12 Months Ended Dec. 31, 2018
[Disclosure Of Supplemental Information [Abstract]]	
Disclosure Of Supplemental Information [text block]	**19. Supplemental information**

19. Supplemental information

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

($M)	Year E Dec 31, 2018
Changes in:	
Accounts receivable	(94,562)
Crude oil inventory	(10,646)
Prepaid expenses	(4,896)
Accounts payable and accrued liabilities	230,567
Income taxes payable	(1,651)
Working capital assumed from acquisitions	(58,841)
Initial recognition of IFRS 16 liability	(10,483)
Foreign exchange	(873)
Changes in non-cash working capital	**48,615**
Changes in non-cash operating working capital	(6,876)
Changes in non-cash investing working capital	55,491
Changes in non-cash working capital	**48,615**

Cash and cash equivalents was comprised of the following:

($M)	As Dec 31, 2018
Cash on deposit with financial institutions	26,604
Guaranteed investment certificates	205
Cash and cash equivalents	**26,809**

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

($M)	Year E 2018
Operating expense	66,095
General and administration expense	42,496
Wages and benefits	**108,591**

The following tables summarize Vermilion's outstanding risk management positions as at December 31, 2018:

Crude Oil	Period	Exercise date (1)	Currency	Bought Put Volume (bbl/d)	Weighted Average Bought Put Price / bbl	Sold Call Volume (bbl/d)	Weighted Average Sold Call Price / bbl	Sold Put Volume (bbl/d)	Wei Av Sol Price
Dated Brent									
3-Way Collar	Sep 2018 - Jun 2019		CAD	2,500	91.20	2,500	98.63	2,500	7
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	
3-Way Collar	Aug 2018 - Jun 2019		USD	500	66.92	500	80.00	500	5
3-Way Collar	Jan 2019 - Dec 2019		USD	500	70.00	500	80.00	500	6
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	
Swap	Jul 2018 - Jun 2019		USD	—	—	—	—	—	
Swap	Jan 2019 - Dec 2019		USD	—	—	—	—	—	
WTI									
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	
3-Way Collar	Jan 2019 - Dec 2019		USD	250	70.00	250	80.25	250	6
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	

North American Gas	Period	Exercise date (1)	Currency	Bought Put Volume (mcf/d)	Weighted Average Bought Put Price / mcf	Sold Call Volume (mcf /d)	Weighted Average Sold Call Price / mcf	Sold Put Volume (mcf d)	Wei Av Sol Price
AECO									
Swap	Dec 2018 - Mar 2019		CAD	—	—	—	—	—	
AECO Basis (AECO less NYMEX Henry Hub)									
Swap	Jan 2019 - Jun 2020		USD	—	—	—	—	—	
AECO Basis (AECO less Chicago NGI)									
Swap	Nov 2018 - Mar 2019		USD	—	—	—	—	—	
NYMEX Henry Hub									
Swap	Jan 2019 - Mar 2019		USD	—	—	—	—	—	
Chicago NGI									

Swap	Dec 2018 - Mar 2019	USD	—	—	—	—	—
SOCAL Border							
Swap (2)	Jan 2019	USD	—	—	—	—	—
Swap (2)	Feb 2019	USD	—	—	—	—	—
Swap (2)	Mar 2019	USD	—	—	—	—	—

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract with Vermilion at the above detailed t

(2) These swaps hedge a physical sales agreement to sell Alberta natural gas production at SOCAL Border pricing less a fixed differential.

European Gas	Period	Exercise date (1)	Currency	Bought Put Volume (mcf/d)	Weighted Average Bought Put Price / mcf	Sold Call Volume (mcf/d)	Weighted Average Sold Call Price / mcf	Sold Put Volume (mcf/d)	Wei Av Sol Price
NBP									
3-Way Collar	Jan 2019 - Dec 2019		EUR	17,197	4.97	17,197	5.65	17,197	
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	
3-Way Collar	Jan 2020 - Dec 2020		EUR	19,654	5.10	19,654	5.92	19,654	
Collar	Oct 2018 - Mar 2019		EUR	3,685	6.40	2,457	7.62	—	
Call	Oct 2018 - Mar 2019		EUR	—	—	12,327	6.28	—	
Swap	Oct 2018 - Mar 2019		EUR	—	—	—	—	—	
Swaption	Jul 2019 - Jun 2021	June 28, 2019	EUR	—	—	—	—	—	
Swaption	Oct 2019 - Mar 2020	June 28, 2019	EUR	—	—	—	—	—	
Swaption	Oct 2020 - Mar 2021	June 28, 2019	EUR	—	—	—	—	—	
Swaption	Oct 2021 - Mar 2022	June 28, 2019	EUR	—	—	—	—	—	
NBP Basis (NBP less NYMEX HH)									
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	
TTF									
3-Way Collar	Oct 2017 - Dec 2019		EUR	7,370	4.59	7,370	5.42	7,370	
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	
3-Way Collar	Jan 2019 - Dec 2019		EUR	12,284	5.05	12,284	5.72	12,284	
3-Way Collar	Jan 2020 - Dec 2020		EUR	7,370	5.37	7,370	6.25	7,370	
Swap	Oct 2017 - Dec 2019		EUR	—	—	—	—	—	
Swap	Jan 2018 - Dec 2019		EUR	—	—	—	—	—	
Swap	Jul 2018 - Dec 2019		EUR	—	—	—	—	—	
Swap	Jan 2019 - Dec 2019		EUR	—	—	—	—	—	

Cross Currency Interest Rate		Receive Notional Amount (USD)	Rate (LIBOR +)	Pay Notional Amount (
Swap	Jan 2019	1,018,563,000	1.70 %	1,354,900

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

Significant accounting policies (Policies)	12 Months Ended Dec. 31, 2018
Disclosure Of Significant Accounting Policies [Abstract]	
Description of accounting policy for accounting framework [text block]	*Accounting framework* The consolidated financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as iss Accounting Standards Board ("IASB").
Description of accounting policy for principles of consolidation [text block]	*Principles of consolidation* The consolidated financial statements include the accounts of Vermilion Energy Inc. and its subsidiaries. Vermilion's subsidiaries of the jurisdictions that Vermilion operates as described in Note 4 including: Canada, France, Netherlands, Germany, Ireland (thro Cayman Islands incorporated company), Australia, the United States, Hungary, Slovakia, and Croatia. Vermilion Energy Inc. dire holding companies owns all of the voting securities of each material subsidiary. Transactions between Vermilion Energy Inc. and its eliminated. Vermilion accounts for joint operations by recognizing the Company's share of assets, liabilities, income, and expenses.
Description of accounting policy for exploration and evaluation expenditures [text block]	*Exploration and evaluation assets* Vermilion classifies costs as exploration and evaluation ("E&E") assets when they relate to exploring and evaluating an area for whi license or right to explore and extract resources. E&E costs may include: geological and geophysical costs; land and license acquis the drilling, completion, and testing of exploration wells. E&E costs are reclassified to capital assets if the technical feasibility and commercial viability of the area can be determined. E&E impairment prior to any reclassification. The technical feasibility and commercial viability of extracting the reserves is considered t proved and probable reserves are identified. Costs incurred prior to the acquisition of the legal rights to explore an area are expensed as incurred. If reserves are not found or the area is abandoned, the related E&E costs are depreciated over a period not greater than five years. If an exploration lice commencement of exploration activities, the cost of the exploration license is written off through depreciation in the year of expiration
Description of accounting policy for property, plant and equipment [text block]	*Capital assets* Vermilion recognizes capital assets at cost less accumulated depletion, depreciation and impairment losses. Costs include directly a for the drilling, completion, and tie-in of wells and the construction of production and processing facilities. When components of capital assets are replaced, disposed of, or no longer in use, they are derecognized. Gains and losses on disp determined by comparing the proceeds of disposal compared to the carrying amount.
Description of accounting policy for depreciation expense [text block]	*Depletion and depreciation* Capital assets are grouped into depletion units, which are groups of assets within a specific production area that have similar econo represent the lowest level of disaggregation for which costs are accumulated for the purposes of calculating depletion and depreciati The net carrying value of each depletion unit is depleted using the unit of production method by reference to the ratio of production proved and probable reserves, taking into account the future development costs necessary to bring the applicable reserves into proc For the purposes of the depletion calculations, oil and gas reserves are converted to a common unit of measure on the basis of the based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent.
Description of accounting policy for impairment of assets [text block]	*Impairment of capital assets and exploration and evaluation assets* Depletion units are aggregated into cash generating units ("CGUs") for impairment testing. CGUs are the lowest level for which th inflows that are largely independent of cash inflows of other groups of assets. CGUs are reviewed for indicators of potential impairme E&E assets are tested for impairment when reclassified to capital assets or when indicators of potential impairment are identified. E for indicators of potential impairment at each reporting date. If indicators of potential impairment are identified, E&E assets are teste of the CGU attributable to the jurisdiction in which the exploration area resides. If an indicator of potential impairment exists, the CGU's carrying value is compared to its recoverable amount. A CGU's recoverable its fair value less costs of disposal and its value-in-use. If the carrying amount of a CGU exceeds its recoverable amount, an impairm reduce the carrying value of the CGU to its recoverable amount. If an impairment loss has been recognized in a prior period, an assessment is performed at each reporting date to determine if the circumstances which led to the impairment loss have reversed. If the change in circumstances results in the recoverable amou carrying value after the impairment loss, then the impairment loss (net of depletion that would otherwise have been recorded) is reve
Description of accounting policy for Lease obligations and right-of-use assets [text block]	*Lease obligations and right-of-use assets* A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exc At the lease commencement date, a lease obligation is recognized at the present value of future lease payments, typically using th borrowing rate. A corresponding right-of-use asset is recognized at the amount of the lease obligation, adjusted for lease incentives costs. Vermilion does not recognize leases for short-term leases with a lease term of 12 months or less, or leases for low-value asse Payments are applied against the lease obligation and interest expense is recognized on the lease obligations using the effecti Depreciation is recognized on the right-of-use asset over the lease term.
Description of accounting policy for determining	*Cash and cash equivalents* Cash and cash equivalents include cash on deposit with financial institutions and guaranteed investment certificates.

components of cash and cash equivalents [text block]	
Description of accounting policy for measuring inventories [text block]	*Crude oil inventory* Crude oil inventory is valued at the lower of cost or net realizable value. The cost of crude oil inventory produced includes related ope and depletion determined on a weighted-average basis.
Description of accounting policy for asset retirement obligation [text block]	*Asset retirement obligations* Vermilion recognizes a provision for asset retirement obligations when an event occurs giving rise to an obligation of uncertain retirement obligations are recognized on the consolidated balance sheet as a long-term liability with a corresponding increase to E&I Asset retirement obligations reflect the present value of estimated future settlement costs. The discount rate used to calculate the pr the jurisdiction the obligation relates to and is reflective of current market assessment of the time value of money and risks specific not been reflected in the cash flow estimates. Asset retirement obligations are remeasured at each reporting period to reflect changes in market rates and estimated future retirement obligations are increased each reporting period to reflect the passage of time with a corresponding charge to accretion ex
Description of accounting policy for recognition of revenue [text block]	*Revenue recognition* Revenue associated with the sale of crude oil and condensate, natural gas, and natural gas liquids is measured based on the c contracts with customers. Revenue from contracts with customers is recognized when or as Vermilion satisfies a performance obligation by transferring condensate, natural gas, or natural gas liquids to a customer at contractually specified transfer points. This transfer coincides with title and the customer taking physical possession of the commodity. Vermilion principally satisfies its performance obligations at a point of revenue recognized relating to performance obligations satisfied over time are not significant. Vermilion invoices customers for delivered products monthly and payment occurs shortly thereafter. Vermilion does not have any co between the transfer of control of the commodity to the customer and payment by the customer exceeds one year. As a result, Ver revenue transactions to reflect significant financing components.
Description of accounting policy for financial instruments [text block]	*Financial instruments* On initial recognition, financial instruments are measured at fair value. Measurement in subsequent periods depends on the clas instrument as described below: • Fair value through profit or loss: Financial instruments under this classification include cash and cash equivalents and deriva • Amortized cost: Financial instruments under this classification include accounts receivable, accounts payable and accr payable, lease obligations, and long-term debt. Accounts receivable are measured net of a loss allowance equal to the lifetime expected credit loss.
Description of accounting policy for share-based payment transactions [text block]	*Equity based compensation* Equity based compensation expense results from equity-settled awards issued under Vermilion's long-term share-based compensa grant date fair value of Vermilion common shares issued under the Company's bonus and employee share savings plans. Vermilion's long-term share-based compensation plans consist of the Vermilion Incentive Plan ("VIP") and a security-based compensa Year Compensation Arrangement"). Equity-settled awards issued under the VIP vest over a period of one to three years while a Five-Year Compensation Arrangement vest in the fifth year following the grant date. Awards under both plans are adjusted upon v factor determined by the Company's Board of Directors. Equity based compensation expense for both plans is recognized over t corresponding adjustment to contributed surplus. The expense recognized is based on the grant date fair value of the awards, an est factor that will be achieved, and an estimate of forfeiture rates based on historical vesting data. Dividends notionally accrue to the a in the determination of grant date fair values. Upon vesting, the amount recognized in contributed surplus is reclassified to sharehold The grant date fair value of the equity-settled awards issued under the VIP and the Five-Year Compensation Arrangement and th Vermilion common shares issued under the Company's bonus and employee share savings plans are determined as the closing pric shares on the Toronto Stock Exchange on the grant date.
Description of accounting policy for earnings per share [text block]	*Per share amounts* Basic net earnings per share is calculated by dividing net earnings by the weighted-average number of shares outstanding during th Diluted net earnings per share is calculated by dividing net earnings by the diluted weighted-average number of shares outstandin diluted weighted-average number of shares outstanding is the sum of the basic weighted-average number of shares outstanding an reduces diluted net earnings per share) the number of shares issuable for equity-settled awards determined using the treasury sto stock method assumes that the unrecognized equity based compensation expense are deemed proceeds used to repurchase Vern the average market price during the period.
Description of accounting policy for foreign currency translation [text block]	*Foreign currency translation* Vermilion Energy Inc.'s functional and presentation currency is the Canadian dollar. Vermilion has subsidiaries that transact and o than Canada and have functional currencies other than the Canadian dollar. Foreign currency translation includes the translation of foreign currency transactions and the translation of foreign operations. Foreign currency transaction translation occur when translating transactions and balances in foreign currencies to the applicab Vermilion Energy Inc. and its subsidiaries. Gains and losses from foreign currency transactions are recorded as foreign exchange currency transaction translation occurs as follows: • Income and expenses are translated at the prevailing rates on the date of the transaction • Non-monetary assets or liabilities are carried at the prevailing rates on the date of the transaction

- Monetary items, including intercompany loans that are not deemed to represent net investments in a foreign subsidiary, are translated a balance sheet date

Foreign operation translation occurs when translating the financial statements of non-Canadian functional currency subsidiaries and when translating intercompany loans that are deemed to represent net investments in a foreign subsidiary. Gains and losse translations are recorded as currency translation adjustments. Foreign operation translations occur as follows:

- Income and expenses are translated at the average exchange rates for the period
- Assets and liabilities are translated at the prevailing rates on the balance sheet date.

Description of accounting policy for income tax [text block]

Income taxes

Deferred tax assets and liabilities are calculated using the balance sheet method. Deferred tax assets and liabilities are recognized of any temporary differences between the amounts recognized on Vermilion's consolidated balance sheet and the respective tax ba enacted or substantively enacted tax rates that are expected to be in effect when the temporary differences are expected to revers in tax rates on deferred taxes is recognized in the period the related legislation is substantively enacted.

Deferred tax assets are recognized to the extent that it is probable that future taxable profits will be available against which t differences can be used. Deferred tax assets are reviewed at each reporting date and are reduced to the extent it is no longer prol benefit will be realized.

Description of accounting policy for business combinations [text block]

Business combinations

Acquisitions of corporations or groups of assets are accounted for as business combinations using the acquisition method if the a a business. Under the acquisition method, assets acquired and liabilities assumed in a business combination (with the exceptio and liabilities) are measured at their fair value. Deferred tax assets or liabilities arising from the assets acquired and liabilities as accordance with the policies described in "Income taxes" above.

If applicable, the excess or deficiency of net assets acquired compared to consideration paid is recognized as a gain on business co on the consolidated balance sheet. Acquisition-related costs incurred to effect a business combination are expensed in the period in

Description of accounting policy for segment reporting [text block]

Segmented information

Vermilion has a decentralized business unit structure designed to manage assets in each country the Company operates in. Each segments derives its revenues solely from the production and sale of petroleum and natural gas.

Vermilion's Corporate segment aggregates costs incurred at the Company's Corporate head office located in Calgary, Alberta, C incurred relating to Vermilion's exploration and production activities in Hungary, Slovakia, and Croatia (Central and Eastern E segments have similar economic characteristics as they do not currently generate material revenue.

Vermilion's chief operating decision maker regularly reviews fund flows from operations generated by each of Vermilion's operatin from operations is a measure of profit or loss that provides the chief operating decision maker with the ability to assess the profi segment and, correspondingly, the ability of each operating segment to fund its share of dividends, asset retirement obligations, and

Description of accounting policy for management judgements and estimation uncertainty [text block]

Management judgments and estimation uncertainty

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, esti that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these esti management has made judgments, estimates, and assumptions are described below.

The measurement of the fair value of capital assets acquired in a business combination and the determination of the recoverable ar units:

- Calculating the fair value of capital assets acquired in a business combination and the recoverable amount of cash generatin of impairments or reversals of previous impairments if indicators of impairment or impairment reversal are identified) future commodity prices and estimated reserves and resources. Reserve and resource estimates are based on: engineerin commodity prices, expected future rates of production, and assumptions regarding the timing and amount of future expend estimates and assumptions can directly impact the calculated fair value of capital assets acquired (and thus the resulting goo combination) and the recoverable amount of a CGU (and thus the resulting impairment loss or recovery).
- In addition, the recoverable amount of a CGU is impacted by the composition of CGUs, which are subject to management' level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of ass Vermilion to determine CGUs vary by jurisdiction due to their unique operating and geographic conditions. In general, V following factors: geographic proximity of the assets within a group to one another, geographic proximity of the group of a assets, homogeneity of the production from the group of assets and the sharing of infrastructure used to process and/or trans in these judgments can directly impact the calculated recoverable amount of a CGU (and thus the resulting impairment loss

The measurement of the carrying value of asset retirement obligations on the balance sheet, including the fair value and subseque retirement obligations assumed in a business combination:

- Asset retirement obligations are based on judgments regarding regulatory requirements, estimates of future costs, assur timing of expenditures, and estimates of the underlying risk inherent to the obligation. The carrying balance of asset re accretion expense may differ due to changes in: laws and regulations, technology, the expected timing of expenditures affecting the discount rate applied.

The recognition and measurement of deferred tax assets and liabilities:

- Tax interpretations, regulations, and legislation in the various jurisdictions in which Vermilion and its subsidiaries operate a interpretation. Changes in laws and interpretations can affect the timing of the reversal of temporary tax differences, the such differences reverse and Vermilion's ability to use tax losses and other tax pools in the future. The Company's incor to audit by taxation authorities in numerous jurisdictions and the results of such audits may increase or decrease the tax li of tax amounts recognized in the consolidated financial statements are based on management's assessment of the tax p consideration of their technical merits, communications with tax authorities and management's view of the most likely outcor
- The extent to which deferred tax assets are recognized are based on estimates of future profitability. These estimates are b commodity prices and estimates of reserves. Judgments, estimates, and assumptions inherent in reserve estimates are des

The measurement of lease obligations and corresponding right-of-use assets:

- The measurement of lease obligations are subject to management's judgments of the applicable incremental borrowing rate term. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depletion and dep differ due to changes in the market conditions and expected lease terms. Applicable incremental borrowing rates are ba economic environment, term, currency, and the underlying risk inherent to the asset. Lease terms are based on assumptio and extension terms that allow for operational flexibility based on future market conditions.

Segmented information (Tables)	12 Months Ended Dec. 31, 2018
Disclosure Of Segmented Information [Abstract]	
Disclosure of operating segments [text block]	Substantially all sales in the France, Netherlands, and Ireland operating segments for the years ended December 31, 2018 and 2017 were to one c segment.

($M)	Canada	France	Netherlands	Year Ended December 31, 2018 Germany	Ireland	Australia	USA
Total assets	3,060,291	918,398	277,348	284,063	709,585	263,739	407,323
Drilling and development	277,857	79,451	17,963	10,863	224	75,638	40,837
Exploration and evaluation	—	307	(480)	4,943	—	—	—
Crude oil and condensate sales	541,844	360,471	2,462	32,704	—	150,733	31,142
NGL sales	56,554	—	—	—	—	—	4,622
Natural gas sales	72,774	131	163,454	49,745	205,150	—	2,701
Royalties	(84,696)	(46,781)	(3,181)	(6,626)	—	—	(10,070)
Revenue from external customers	586,476	313,821	162,735	75,823	205,150	150,733	28,395
Transportation	(29,912)	(10,426)	—	(6,420)	(5,129)	—	—
Operating	(177,499)	(54,690)	(26,681)	(23,048)	(15,366)	(53,199)	(6,421)
General and administration	(6,057)	(14,170)	(1,947)	(7,401)	(8,386)	(4,918)	(6,306)
PRRT	—	—	—	—	—	(4,824)	—
Corporate income taxes	—	(15,084)	(16,561)	—	—	(6,595)	—
Interest expense	—	—	—	—	—	—	—
Realized loss on derivative instruments	—	—	—	—	—	—	—
Realized foreign exchange gain	—	—	—	—	—	—	—
Realized other income	—	—	—	—	—	—	—
Fund flows from operations	**373,008**	**219,451**	**117,546**	**38,954**	**176,269**	**81,197**	**15,668**

($M)	Canada	France	Netherlands	Year Ended December 31, 2017 Germany	Ireland	Australia	USA
Total assets	1,542,193	831,783	203,929	295,026	667,068	236,677	73,867
Drilling and development	148,667	71,087	15,107	6,165	551	29,942	19,074
Exploration and evaluation	—	2,294	16,468	3,366	—	—	—
Crude oil and condensate sales	209,560	268,102	1,864	23,554	—	154,391	14,605
NGL sales	37,809	—	—	—	—	—	456
Natural gas sales	83,534	1	106,196	45,142	153,330	—	294
Royalties	(33,258)	(28,565)	(1,722)	(6,655)	—	—	(4,276)
Revenue from external customers	297,645	239,538	106,338	62,041	153,330	154,391	11,079
Transportation	(17,368)	(14,627)	—	(6,207)	(5,205)	—	(41)
Operating	(80,444)	(51,002)	(21,212)	(20,176)	(17,596)	(50,139)	(1,698)
General and administration	(9,604)	(13,585)	(2,212)	(7,767)	(2,320)	(8,194)	(4,341)
PRRT	—	—	—	—	—	(19,819)	—
Corporate income taxes	—	(10,556)	3,331	—	—	(4,536)	—
Interest expense	—	—	—	—	—	—	—
Realized gain on derivative instruments	—	—	—	—	—	—	—
Realized foreign exchange gain	—	—	—	—	—	—	—
Realized other income	—	—	—	—	—	—	—
Fund flows from operations	**190,229**	**149,768**	**86,245**	**27,891**	**128,209**	**71,703**	**4,999**

Reconciliation of fund flows from operations to net earnings:

($M)	Year E Dec 31, 2018
Fund flows from operations	**838,652**
Accretion	**(31,219)**
Depletion and depreciation	**(609,056)**
Gain on business combinations	**128,208**
Unrealized gain (loss) on derivative instruments	**109,326**
Equity based compensation	**(60,746)**
Unrealized foreign exchange (loss) gain	**(63,243)**
Unrealized other expense	**(801)**
Deferred tax	**(39,471)**
Net earnings	**271,650**

Business combinations (Tables)	12 Months Ended Dec. 31, 2018
Southeast Saskatchewan and Southwest Manitoba [Member]	
Disclosure of detailed information about business combinations [text block]	The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are detailed in

($M)
Cash paid to vendor
Total consideration

($M)	Alloc
Capital assets	
Deferred tax assets	
Acquired working capital	
Long-term debt	
Asset retirement obligations	
Net assets acquired	

Spartan Energy Corp [Member]	
Disclosure of detailed information about business combinations [text block]	The total consideration paid and the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are det

($M)
Shares issued for acquisition
Total consideration

($M)	Alloc
Capital assets	
Deferred tax assets	
Long-term debt	
Asset retirement obligations	
Lease obligations	
Assumed working capital deficit	
Net assets acquired	

Wyoming [Member]	
Disclosure of detailed information about business combinations [text block]	The total consideration paid and the fair value of the assets acquired and liabilities assumed at the date of acquisition are detailed in

($M)
Cash paid to vendor
Total consideration

($M)	Alloc
Capital assets	
Deferred tax liability	
Asset retirement obligations	
Assumed working capital deficit	
Net assets acquired	
Gain on business combination	
Total net assets acquired, net of gain on business combination	

Shell EP Ireland Limited [Member]	
Disclosure of detailed information about business combinations [text block]	The total consideration paid and the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are det

($M)
Cash paid to vendor
Cash acquired
Contingent consideration
Total consideration

($M)	Alloc
Capital assets	
Deferred tax assets	
Assumed working capital deficit	
Lease obligations	
Asset retirement obligations	
Net assets acquired	
Gain on business combination	
Total net assets acquired, net of gain on business combination	

Capital assets (Tables)	12 Months Ended Dec. 31, 2018
Disclosure of detailed information about property, plant and equipment [abstract]	
Disclosure of detailed information about property, plant and equipment [text block]	The following table reconciles the change in Vermilion's capital assets:

($M)	2018
Balance at January 1	**3,337,965**
Acquisitions	**1,975,327**
Additions	**503,842**
Increase in right-of-use assets	**98,343**
Transfers from exploration and evaluation assets	**29,615**
Depletion and depreciation	**(605,994)**
Changes in asset retirement obligations	**(100,876)**
Foreign exchange	**78,651**
Balance at December 31	**5,316,873**
Cost	**9,202,604**
Accumulated depletion and depreciation	**(3,885,731)**
Carrying amount at December 31	**5,316,873**

Disclosure of detailed information about right of use assets [Table Text Block]

The following table discloses the carrying balance and depreciation charge relating to right-of-use assets by class of underlying ass ended December 31, 2018:

($M)	Depreciation
Office space	**9,119**
Gas processing facilities	**5,491**
Oil storage facilities	**2,728**
Vehicles and equipment	**2,020**
Total	**19,358**

Exploration and evaluation assets (Tables)	12 Months Ended Dec. 31, 2018
Exploration and evaluation assets [member]	
Disclosure Of Exploration And Evaluation Assets [Line Items]	
Disclosure of detailed information about exploration and evaluation assets [text block]	The following table reconciles the change in Vermilion's exploration and evaluation assets:

($M)	2018
Balance at January 1	**292,278**
Acquisitions	**28,572**
Additions	**14,372**
Changes in asset retirement obligations	**629**
Transfers to capital assets	**(29,615)**
Depreciation	**(5,942)**
Foreign exchange	**3,001**
Balance at December 31	**303,295**
Cost	**371,015**
Accumulated depreciation	**(67,720)**
Carrying amount at December 31	**303,295**

Asset retirement obligations (Tables)	12 Months Ended Dec. 31, 2018
Disclosure Of Asset Retirement Obligations [Abstract]	
Disclosure of other provisions [text block]	The following table reconciles the change in Vermilion's asset retirement obligations:

($M)	2018
Balance at January 1	**517,180**
Additional obligations recognized	**211,580**
Changes in estimated abandonment timing and costs	**(98,158)**
Obligations settled	**(15,765)**
Accretion	**31,219**
Changes in discount rates	**(6,646)**
Foreign exchange	**10,754**
Balance at December 31	**650,164**

Disclosure of detailed information about risk free rates used to discount the obligations [text block]

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

	Dec 31,
Canada	
France	
Netherlands	
Germany	
Ireland	
Australia	
USA	

Derivative instruments (Tables)	12 Months Ended Dec. 31, 2018
Disclosure Of Derivative instruments [Abstract]	
Disclosure of detailed information about change in fair value of derivative instruments [text block]	The following table reconciles the change in the fair value of Vermilion's derivative instruments:

($M)	Year E Dec 31, 2018
Fair value of contracts, beginning of year	**(70,713)**
Reversal of opening contracts settled during the year	**57,719**
Assumed in acquisitions	**(274)**
Realized (loss) gain on contracts settled during the year	**(111,258)**
Unrealized gain (loss) during the year on contracts outstanding at the end of the year	**51,607**
Net receipt from counterparties on contract settlements during the year	**111,258**
Fair value of contracts, end of year	**38,339**
Comprised of:	
Current derivative asset	**95,667**
Current derivative liability	**(41,016)**
Non-current derivative asset	**1,215**
Non-current derivative liability	**(17,527)**
Fair value of contracts, end of year	**38,339**

Disclosure of detailed information of about loss gain on derivative instruments [text block]	The loss (gain) on derivative instruments for 2018 and 2017 were comprised of the following:

($M)	Year E Dec 31, 2018
Realized loss (gain) on contracts settled during the year	**111,258**
Reversal of opening contracts settled during the year	**(57,719)**
Unrealized (gain) loss on contracts outstanding at the end of the year	**(51,607)**
Loss (gain) on derivative instruments	**1,932**

Leases (Tables)

12 Months Ended Dec. 31, 2018

Disclosure of leases [Abstract]

Disclosure of finance lease and operating lease by lessee [text block]

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

($M)	A Dec 31, 2018
Less than 1 year	30,641
1 - 3 years	50,024
4 - 5 years	34,313
After 5 years	42,739
Total lease payments	157,717
Amounts representing interest	(24,583
Present value of net lease payments	133,134
Current portion of lease obligations	(24,945
Non-current portion of lease obligations	108,189

Taxes (Tables) | **12 Months Ended Dec. 31, 2018**

Disclosure Of Taxes [Abstract]

Disclosure of detailed information of deferred tax asset and liability [text block]

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

($M)	As a Dec 31, 2018
Deferred tax assets:	
Non-capital losses	487,398
Capital assets	(296,591)
Asset retirement obligations	38,429
Derivative contracts	(11,937)
Unrealized foreign exchange	(1,873)
Other	3,985
Deferred tax assets	**219,411**
Deferred tax liabilities:	
Capital assets	(319,553)
Non-capital losses	57,785
Asset retirement obligations	(51,031)
Unrealized foreign exchange	(10,715)
Derivative contracts	—
Other	5,380
Deferred tax liabilities	**(318,134)**

Disclosure of detailed information about reconciliation of accounting profit multiplied by applicable tax rates [text block]

Income tax expense differs from the amount that would have been expected if the reported earnings had been subject only to the sta tax rate as follows:

($M)	Year I Dec 31, 2018
Earnings before income taxes	354,698
Canadian corporate tax rate	27.0%
Expected tax expense	95,768
Increase (decrease) in taxes resulting from:	
Petroleum resource rent tax rate (PRRT) differential (1)	5,349
Foreign tax rate differentials (1), (2)	3,086
Equity based compensation expense	13,883
Amended returns and changes to estimated tax pools and tax positions	(873)
Statutory rate changes and the estimated reversal rates associated with temporary differences (3)	—
(Re-recognition) de-recognition of deferred tax assets	(26,931)
Adjustment for uncertain tax positions	8,080
Gain on business combinations	(28,812)
Other non-deductible items	13,498
Provision for income taxes	**83,048**

(1) In Australia, current taxes include both corporate income tax rates and PRRT. Corporate income tax rates were applied at a rat applied at a rate of 40%.

(2) The applicable tax rates for 2018 were: 34.4% in France, 50.0% in the Netherlands, 30.2% in Germany, 25.0% in Ireland, and 21

(3) On December 22, 2017, the Tax Cuts and Jobs Act was signed into law in the United States reducing the U.S. federal corpor 35% to 21%. On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 pr decrease of the French standard corporate income tax rate from 34.43% to 25.825% by 2022. On December 18, 2018, the Dut the 2019 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% to 20.5% by 2021, with the first reduction plar Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not exp impact to Vermilion taxes in the Netherlands.

Long-term debt (Tables)	12 Months Ended Dec. 31, 2018
Disclosure of Long-Term Debt [Line Items]	
Disclosure of detailed information about borrowings [text block]	The following table summarizes Vermilion's outstanding long-term debt:

($M)	As a Dec 31, 2018
Revolving credit facility	1,392,206
Senior unsecured notes	404,001
Long-term debt	**1,796,207**

Disclosure of detailed information about change long-term debt [text block]

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

($M)	2018
Balance at January 1	**1,270,330**
Borrowings (repayments) on the revolving credit facility	251,155
Issuance of senior unsecured notes	—
Assumed on acquisitions [(1)]	188,496
Amortization of transaction costs and prepaid interest	2,286
Foreign exchange	83,940
Balance at December 31	**1,796,207**

(1) Pursuant to the acquisitions described in Note 5 (Business Combinations), Vermilion assumed the credit facilities of the acquired companies and them following the respective acquisitions using proceeds from Vermilion's revolving credit facility.

Disclosure of detailed information about borrowings financial covenants [text block]

As at December 31, 2018, the revolving credit facility was subject to the following financial covenants:

Financial covenant	Limit	As Dec 31, 2018
Consolidated total debt to consolidated EBITDA	4.0	1.72
Consolidated total senior debt to consolidated EBITDA	3.5	1.34
Consolidated total senior debt to total capitalization	55%	30%

Disclosure of detailed information about redemption price of unsecured notes [text block]

Year
2020
2021
2022
2023 and thereafter

Revolving Credit Facilities [Member]

Disclosure of Long-Term Debt [Line Items]

Disclosure of detailed information about borrowings [text block]

At December 31, 2018, Vermilion had in place a bank revolving credit facility maturing May 31, 2022 with the following terms:

($M)	As a Dec 31, 2018
Total facility amount	1,800,000
Amount drawn	(1,392,206)
Letters of credit outstanding	(15,400)
Unutilized capacity	**392,394**

Shareholders' capital (Tables)	12 Months Ended Dec. 31, 2018
Disclosure of Shareholder's Capital [Abstract]	
Disclosure of classes of share capital [text block]	The following table reconciles the change in Vermilion's shareholders' capital:

	2018		
Shareholders' Capital	**Shares ('000s)**	**Amount ($M)**	**Sh ('0**
Balance at January 1	**122,119**	**2,650,706**	118
Shares issued for acquisition	**27,883**	**1,234,676**	
Shares issued for the Dividend Reinvestment Plan	**1,179**	**49,051**	2
Vesting of equity based awards	**1,025**	**54,057**	1
Shares issued for equity based compensation	**314**	**12,565**	
Share-settled dividends on vested equity based awards	**184**	**7,773**	
Balance at December 31	**152,704**	**4,008,828**	122

Capital disclosures (Tables)	12 Months Ended Dec. 31, 2018
Disclosure Of Capital Disclosures [Abstract]	
Disclosure of detailed information about debt to funds flow ratio [text block]	The following table calculates Vermilion's ratio of net debt to fund flows from operations:

($M except as indicated)	Year E Dec 31, 2018
Long-term debt	1,796,207
Current liabilities	563,199
Current assets	(429,877)
Net debt	**1,929,529**
Ratio of net debt to fund flows from operations	**2.30**

Equity based compensation (Tables)	12 Months Ended Dec. 31, 2018
Vermilion incentive plan [Member]	
Disclosure Of Equity Based Compensation [Line Items]	
Disclosure of number and weighted average exercise prices of other equity instruments [text block]	The following table summarizes the number of awards outstanding under the VIP and the Five-Year Compensation Arrangement:

Number of Awards ('000s)	2018
Opening balance	**1,685**
Granted	**932**
Vested	**(520)**
Forfeited	**(166)**
Closing balance	**1,931**

Per share amounts (Tables)	12 Months Ended Dec. 31, 2018
Disclosure Of Per Share Amounts [Abstract]	
Disclosure of detailed information about basic and diluted earnings per share [text block]	Basic and diluted net earnings per share have been determined based on the following:

($M except per share amounts)	Year E Dec 31, 2018
Net earnings	**271,650**
Basic weighted average shares outstanding ('000s)	**140,619**
Dilutive impact of equity based compensation ('000s)	**1,716**
Diluted weighted average shares outstanding ('000s)	**142,335**
Basic earnings per share	**1.93**
Diluted earnings per share	**1.91**

Financial instruments (Tables)	12 Months Ended Dec. 31, 2018
Disclosure of detailed information about financial instruments [abstract]	
Disclosure of detailed information about financial instruments [text block]	The following table summarizes information relating to Vermilion’s financial instruments:

($M)	As at Dec 31, 2018 Carrying value	Fair value	As a Carrying va
Fair value through profit or loss			
Cash and cash equivalents	**26,809**	**26,809**	46,5
Derivative assets	**96,882**	**96,882**	20,5
Derivative liabilities	**(58,543)**	**(58,543)**	(91,2
Amortized cost			
Accounts receivable	**260,322**	**260,322**	165,7
Accounts payable and accrued liabilities	**(449,651)**	**(449,651)**	(219,0
Dividends payable	**(35,122)**	**(35,122)**	(26,2
Long-term debt	**(1,796,207)**	**(1,781,809)**	(1,270,3

Disclosure Of Detailed Information On Sensitivity Of Fair Value Measures Explanatory [Text Block]

The following table summarizes the increase (positive values) or decrease (negative values) to net earnings before tax due to a Vermilion’s financial instruments as a result of a change in the relevant market risk variable. This analysis does not attempt to reflec between the relevant risk variables.

($M)	Dec 31, 2018
Currency risk - Euro to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the Euro	**(2,205)**
$0.01 decrease in strength of the Canadian dollar against the Euro	**2,205**
Currency risk - US dollar to Canadian dollar	
$0.01 increase in strength of the Canadian dollar against the US $	**2,981**
$0.01 decrease in strength of the Canadian dollar against the US $	**(2,981)**
Commodity price risk - Crude oil	
US $5.00/bbl increase in crude oil price used to determine the fair value of derivatives	**(18,421)**
US $5.00/bbl decrease in crude oil price used to determine the fair value of derivatives	**17,351**
Commodity price risk - European natural gas	
€ 0.5/GJ increase in European natural gas price used to determine the fair value of derivatives	**(36,508)**
€ 0.5/GJ decrease in European natural gas price used to determine the fair value of derivatives	**33,005**

Disclosure of maturity analysis for non-derivative financial liabilities [text block]

The following table summarizes Vermilion’s undiscounted non-derivative financial liabilities and their contractual maturities:

($M)	1 month	1 month to 3 months	3 months to 1 year
December 31, 2018	167,491	306,927	10,355
December 31, 2017	99,092	138,273	7,974

Related party disclosures (Tables)	12 Months Ended Dec. 31, 2018
Disclosure Of Related Party Disclosures [Abstract]	
Disclosure of information about key management personnel [text block]	The following table summarizes the compensation of directors and other members of key management personnel during the years er and 2017:

($M)	Year E Dec 31, 2018
Short-term benefits	**6,018**
Share-based payments	**16,309**
	22,327
Number of individuals included in the above amounts	**18**

Supplemental information (Tables)	12 Months Ended Dec. 31, 2018
Disclosure Of Supplemental Information [Abstract]	
Disclosure of cash flow statement [text block]	Changes in non-cash working capital was comprised of the following:

($M)	Year E Dec 31, 2018
Changes in:	
Accounts receivable	(94,562)
Crude oil inventory	(10,646)
Prepaid expenses	(4,896)
Accounts payable and accrued liabilities	230,567
Income taxes payable	(1,651)
Working capital assumed from acquisitions	(58,841)
Initial recognition of IFRS 16 liability	(10,483)
Foreign exchange	(873)
Changes in non-cash working capital	**48,615**
Changes in non-cash operating working capital	(6,876)
Changes in non-cash investing working capital	55,491
Changes in non-cash working capital	**48,615**

Disclosure of cash and cash equivalents [text block]

Cash and cash equivalents was comprised of the following:

($M)	As Dec 31, 2018
Cash on deposit with financial institutions	26,604
Guaranteed investment certificates	205
Cash and cash equivalents	**26,809**

Disclosure of employee benefits [text block]

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

($M)	Year E 2018
Operating expense	66,095
General and administration expense	42,496
Wages and benefits	**108,591**

Disclosure of detailed information about outstanding risk management positions [Text Block]

The following tables summarize Vermilion's outstanding risk management positions as at December 31, 2018:

Crude Oil	Period	Exercise date [1]	Currency	Bought Put Volume (bbl/d)	Weighted Average Bought Put Price / bbl	Sold Call Volume (bbl/d)	Weighted Average Sold Call Price / bbl	Sold Put Volume (bbl/d)	Wei Av Sol Price
Dated Brent									
3-Way Collar	Sep 2018 - Jun 2019		CAD	2,500	91.20	2,500	98.63	2,500	7
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	
3-Way Collar	Aug 2018 - Jun 2019		USD	500	66.92	500	80.00	500	5
3-Way Collar	Jan 2019 - Dec 2019		USD	500	70.00	500	80.00	500	6
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	
Swap	Jul 2018 - Jun 2019		USD	—	—	—	—	—	
Swap	Jan 2019 - Dec 2019		USD	—	—	—	—	—	
WTI									
Swap	Jan 2019 - Dec 2019		CAD	—	—	—	—	—	
3-Way Collar	Jan 2019 - Dec 2019		USD	250	70.00	250	80.25	250	6
Swap	Apr 2018 - Mar 2019		USD	—	—	—	—	—	

North American Gas	Period	Exercise date [1]	Currency	Bought Put Volume (mcf/d)	Weighted Average Bought Put Price / mcf	Sold Call Volume (mcf /d)	Weighted Average Sold Call Price / mcf	Sold Put Volume (mcf d)	Wei Av Sol Price
AECO									
Swap	Dec 2018 - Mar 2019		CAD	—	—	—	—	—	
AECO Basis (AECO less NYMEX Henry Hub)									
Swap	Jan 2019 - Jun 2020		USD	—	—	—	—	—	
AECO Basis (AECO less Chicago NGI)									
Swap	Nov 2018 - Mar 2019		USD	—	—	—	—	—	
NYMEX Henry Hub									
Swap	Jan 2019 - Mar 2019		USD	—	—	—	—	—	
Chicago NGI									
Swap	Dec 2018 - Mar 2019		USD	—	—	—	—	—	
SOCAL Border									
Swap [2]	Jan 2019		USD	—	—	—	—	—	
Swap [2]	Feb 2019		USD	—	—	—	—	—	
Swap [2]	Mar 2019		USD	—	—	—	—	—	

(1) The sold swaption instrument allows the counterparty, at the specified date, to enter into a derivative instrument contract with Vermilion at the above detailed t

(2) These swaps hedge a physical sales agreement to sell Alberta natural gas production at SOCAL Border pricing less a fixed differential.

European Gas	Period	Exercise date (1)	Currency	Bought Put Volume (mcf/d)	Weighted Average Bought Put Price / mcf	Sold Call Volume (mcf/d)	Weighted Average Sold Call Price / mcf	Sold Put Volume (mcf/d)	Wei Av Sol Price
NBP									
3-Way Collar	Jan 2019 - Dec 2019		EUR	17,197	4.97	17,197	5.65	17,197	
3-Way Collar	Jan 2019 - Dec 2020		EUR	7,370	4.96	7,370	5.76	7,370	
3-Way Collar	Jan 2020 - Dec 2020		EUR	19,654	5.10	19,654	5.92	19,654	
Collar	Oct 2018 - Mar 2019		EUR	3,685	6.40	2,457	7.62	—	
Call	Oct 2018 - Mar 2019		EUR	—	—	12,327	6.28	—	
Swap	Oct 2018 - Mar 2019		EUR	—	—	—	—	—	
Swaption	Jul 2019 - Jun 2021	June 28, 2019	EUR	—	—	—	—	—	
Swaption	Oct 2019 - Mar 2020	June 28, 2019	EUR	—	—	—	—	—	
Swaption	Oct 2020 - Mar 2021	June 28, 2019	EUR	—	—	—	—	—	
Swaption	Oct 2021 - Mar 2022	June 28, 2019	EUR	—	—	—	—	—	
NBP Basis (NBP less NYMEX HH)									
Collar	Jan 2019 - Sep 2020		USD	7,500	2.07	7,500	4.00	—	
TTF									
3-Way Collar	Oct 2017 - Dec 2019		EUR	7,370	4.59	7,370	5.42	7,370	
3-Way Collar	Jan 2018 - Dec 2019		EUR	3,685	4.74	3,685	5.52	3,685	
3-Way Collar	Jan 2019 - Dec 2019		EUR	12,284	5.05	12,284	5.72	12,284	
3-Way Collar	Jan 2020 - Dec 2020		EUR	7,370	5.37	7,370	6.25	7,370	
Swap	Oct 2017 - Dec 2019		EUR	—	—	—	—	—	
Swap	Jan 2018 - Dec 2019		EUR	—	—	—	—	—	
Swap	Jul 2018 - Dec 2019		EUR	—	—	—	—	—	
Swap	Jan 2019 - Dec 2019		EUR	—	—	—	—	—	

Cross Currency Interest Rate		Receive Notional Amount (USD)	Rate (LIBOR +)	Pay Notional Amount (
Swap	Jan 2019	1,018,563,000	1.70 %	1,354,900

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

Changes in accounting pronouncements (Details Textual) $ in Thousands, $ in Millions	Dec. 31, 2018 CAD ($)	Jan. 01, 2018 USD ($)	Dec. 31, 2017 CAD ($)	Dec. 31, 2017 USD ($)
Changes In Accounting Pronouncements [Line Items]				
Right-of-use assets	$ 133,946			
Non-current lease liabilities	$ 108,189		$ 15,807	
Weighted average lessee's incremental borrowing rate applied to lease liabilities recognised at date of initial application of IFRS 16	5.40%		5.40%	5.40%
Current lease liabilities	$ 11,000			
Operating Lease Commitment				$ 40.2
Lease liabilities	28,000			$ 34.3
Increase in Lease Liability		$ 62.8		
At cost or in accordance with IFRS 16 within fair value model [member]				
Changes In Accounting Pronouncements [Line Items]				
Lease liabilities		$ 97.1		
Capital assets [Member]				
Changes In Accounting Pronouncements [Line Items]				
Right-of-use assets	97,100			
Lease Obligations [Member]				
Changes In Accounting Pronouncements [Line Items]				
Non-current lease liabilities	$ 86,100			

Segmented information (Details) - CAD ($) $ in Thousands	12 Months Ended Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Segmented Information [Line Items]		
Total assets	$ 6,270,671	$ 3,974,965
Drilling and development	503,842	290,593
Exploration and evaluation	14,372	29,856
Royalties	(152,167)	(74,476)
Revenue from external customers	1,525,950	1,024,362
Transportation	(51,887)	(43,448)
Operating	(357,014)	(242,267)
General and administration	(51,929)	(54,373)
Current tax income (expense)	(43,577)	(32,107)
Interest expense	(72,759)	(57,313)
Fund flows from operations	838,652	602,565
Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Total assets	6,270,671	3,974,965
Drilling and development	503,842	290,593
Exploration and evaluation	14,372	29,856
Crude oil and condensate sales	1,119,356	672,076
NGL sales	61,176	38,265
Natural gas sales	497,585	388,497
Royalties	(152,167)	(74,476)
Revenue from external customers	1,525,950	1,024,362
Transportation	(51,887)	(43,448)
Operating	(357,014)	(242,267)
General and administration	(51,929)	(54,373)
Interest expense	(72,759)	(57,313)
Realized loss on derivative instruments	(111,258)	4,721
Realized other income	883	674
Fund flows from operations	838,652	602,565
Reportable segments [member] | Operating Segments [Member]		
Disclosure Of Segmented Information [Line Items]		
Realized foreign exchange gain	243	2,316
PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	(4,824)	(19,819)
Corporate income tax [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	(38,753)	(12,288)
CANADA | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		

Total assets	3,060,291	1,542,193
Drilling and development	277,857	148,667
Exploration and evaluation	0	0
Crude oil and condensate sales	541,844	209,560
NGL sales	56,554	37,809
Natural gas sales	72,774	83,534
Royalties	(84,696)	(33,258)
Revenue from external customers	586,476	297,645
Transportation	(29,912)	(17,368)
Operating	(177,499)	(80,444)
General and administration	(6,057)	(9,604)
Interest expense	0	0
Realized loss on derivative instruments	0	0
Realized foreign exchange gain	0	0
Realized other income	0	0
Fund flows from operations	373,008	190,229
CANADA | PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
CANADA | Corporate income tax [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
FRANCE | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Total assets	918,398	831,783
Drilling and development	79,451	71,087
Exploration and evaluation	307	2,294
Crude oil and condensate sales	360,471	268,102
NGL sales	0	0
Natural gas sales	131	1
Royalties	(46,781)	(28,565)
Revenue from external customers	313,821	239,538
Transportation	(10,426)	(14,627)
Operating	(54,690)	(51,002)
General and administration	(14,170)	(13,585)
Interest expense	0	0
Realized loss on derivative instruments	0	0
Realized foreign exchange gain	0	0
Realized other income	0	0
Fund flows from operations	219,451	149,768
FRANCE | PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
FRANCE | Corporate income tax [Member] | Reportable segments [member]		

Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	(15,084)	(10,556)
NETHERLANDS | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Total assets	277,348	203,929
Drilling and development	17,963	15,107
Exploration and evaluation	(480)	16,468
Crude oil and condensate sales	2,462	1,864
NGL sales	0	0
Natural gas sales	163,454	106,196
Royalties	(3,181)	(1,722)
Revenue from external customers	162,735	106,338
Transportation	0	0
Operating	(26,681)	(21,212)
General and administration	(1,947)	(2,212)
Interest expense	0	0
Realized loss on derivative instruments	0	0
Realized foreign exchange gain	0	0
Realized other income	0	0
Fund flows from operations	117,546	86,245
NETHERLANDS | PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
NETHERLANDS | Corporate income tax [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	(16,561)	3,331
GERMANY | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Total assets	284,063	295,026
Drilling and development	10,863	6,165
Exploration and evaluation	4,943	3,366
Crude oil and condensate sales	32,704	23,554
NGL sales	0	0
Natural gas sales	49,745	45,142
Royalties	(6,626)	(6,655)
Revenue from external customers	75,823	62,041
Transportation	(6,420)	(6,207)
Operating	(23,048)	(20,176)
General and administration	(7,401)	(7,767)
Interest expense	0	0
Realized loss on derivative instruments	0	0
Realized foreign exchange gain	0	0
Realized other income	0	0

Fund flows from operations	38,954	27,891
GERMANY | PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
GERMANY | Corporate income tax [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
IRELAND | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Total assets	709,585	667,068
Drilling and development	224	551
Exploration and evaluation	0	0
Crude oil and condensate sales	0	0
NGL sales	0	0
Natural gas sales	205,150	153,330
Royalties	0	0
Revenue from external customers	205,150	153,330
Transportation	(5,129)	(5,205)
Operating	(15,366)	(17,596)
General and administration	(8,386)	(2,320)
Interest expense	0	0
Realized loss on derivative instruments	0	0
Realized foreign exchange gain	0	0
Realized other income	0	0
Fund flows from operations	176,269	128,209
IRELAND | PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
IRELAND | Corporate income tax [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
AUSTRALIA | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Total assets	263,739	236,677
Drilling and development	75,638	29,942
Exploration and evaluation	0	0
Crude oil and condensate sales	150,733	154,391
NGL sales	0	0
Natural gas sales	0	0
Royalties	0	0
Revenue from external customers	150,733	154,391
Transportation	0	0
Operating	(53,199)	(50,139)
General and administration	(4,918)	(8,194)

Interest expense	0	0
Realized loss on derivative instruments	0	0
Realized foreign exchange gain	0	0
Realized other income	0	0
Fund flows from operations	81,197	71,703
AUSTRALIA | PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	(4,824)	(19,819)
AUSTRALIA | Corporate income tax [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	(6,595)	(4,536)
UNITED STATES | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Total assets	407,323	73,867
Drilling and development	40,837	19,074
Exploration and evaluation	0	0
Crude oil and condensate sales	31,142	14,605
NGL sales	4,622	456
Natural gas sales	2,701	294
Royalties	(10,070)	(4,276)
Revenue from external customers	28,395	11,079
Transportation	0	(41)
Operating	(6,421)	(1,698)
General and administration	(6,306)	(4,341)
Interest expense	0	0
Realized loss on derivative instruments	0	0
Realized foreign exchange gain	0	0
Realized other income	0	0
Fund flows from operations	15,668	4,999
UNITED STATES | PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
UNITED STATES | Corporate income tax [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
Corporate | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Total assets	349,924	124,422
Drilling and development	1,009	0
Exploration and evaluation	9,602	7,728
Crude oil and condensate sales	0	0
NGL sales	0	0
Natural gas sales	3,630	0

Royalties	(813)	0
Revenue from external customers	2,817	0
Transportation	0	0
Operating	(110)	0
General and administration	(2,744)	(6,350)
Interest expense	(72,759)	(57,313)
Realized loss on derivative instruments	(111,258)	4,721
Realized other income	883	674
Fund flows from operations	(183,441)	(56,479)
Corporate | Reportable segments [member] | Operating Segments [Member]		
Disclosure Of Segmented Information [Line Items]		
Realized foreign exchange gain	243	2,316
Corporate | PRRT [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	0	0
Corporate | Corporate income tax [Member] | Reportable segments [member]		
Disclosure Of Segmented Information [Line Items]		
Current tax income (expense)	$ (513)	$ (527)

Segmented information (Details 1) - CAD ($) $ in Thousands	12 Months Ended Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Segmented Information [Abstract]		
Fund flows from operations	$ 838,652	$ 602,565
Accretion	(31,219)	(26,971)
Depletion and depreciation	(609,056)	(491,683)
Gain on business combinations	128,208	0
Unrealized gain (loss) on derivative instruments	109,326	(1,062)
Equity based compensation	(60,746)	(61,579)
Unrealized foreign exchange (loss) gain	(63,243)	71,742
Unrealized other expense	(801)	(637)
Deferred tax	(39,471)	(30,117)
Net earnings	$ 271,650	$ 62,258

Business combinations (Details) - CAD ($) $ in Thousands	12 Months Ended				
	Dec. 31, 2018	Dec. 31, 2017	Aug. 31, 2018	May 28, 2018	Feb. 15, 2018
Disclosure of detailed information about business combination [line items]					
Lease obligations	$ (108,189)	$ (15,807)			
Gain on business combination	128,208	$ 0			
Southeast Saskatchewan and Southwest Manitoba [Member]					
Disclosure of detailed information about business combination [line items]					
Cash paid to vendor					$ 53,288
Total consideration					53,288
Capital assets					67,549
Deferred tax assets					26,914
Acquired working capital					1,577
Long-term debt					(38,300)
Asset retirement obligations					(4,452)
Net assets acquired					$ 53,288
Spartan Energy Corp [Member]					
Disclosure of detailed information about business combination [line items]					
Shares issued for acquisition				$ 1,235,221	
Total consideration				1,235,221	
Capital assets				1,401,686	
Deferred tax assets				123,813	
Long-term debt				(150,196)	
Asset retirement obligations				(92,149)	
Lease obligations				(25,455)	
Assumed working capital deficit				(22,478)	
Net assets acquired				$ 1,235,221	
Wyoming [Member]					
Disclosure of detailed information about business combination [line items]					
Cash paid to vendor			$ 189,014		
Total consideration			189,014		
Capital assets			284,333		
Deferred tax liability			(19,019)		
Asset retirement obligations			(4,821)		
Assumed working capital deficit			(2,651)		
Net assets acquired			257,842		

Gain on business combination	(68,828)	
Total net assets acquired, net of gain on business combination		$ 189,014
Shell E&P Ireland Limited [Member]		
Disclosure of detailed information about business combination [line items]		
Cash paid to vendor	40,805	
Cash acquired	(82,116)	
Contingent consideration	290	
Total consideration	(41,021)	
Capital assets	53,368	
Deferred tax assets	4,239	
Asset retirement obligations	(1,565)	
Lease obligations	(2,234)	
Assumed working capital deficit	(35,449)	
Net assets acquired	18,359	
Gain on business combination	(59,380)	
Total net assets acquired, net of gain on business combination	$ (41,021)	

Business combinations (Details Textual) $ / shares in Units, $ in Thousands, € in Millions, $ in Millions	1 Months Ended	12 Months Ended				
	May 28, 2018 CAD ($) $ / shares	Dec. 31, 2018 CAD ($)	Dec. 31, 2018 USD ($)	Dec. 31, 2018 EUR (€)	Aug. 31, 2018 CAD ($)	Feb. 15, 2018 CAD ($)
Southeast Saskatchewan and Southwest Manitoba [Member]						
Cash flows from used in operations		$ 1,000				
Revenue of acquiree since acquisition date		18,700				
Revenue of combined entity as if combination occurred at beginning of period		2,900				
Profit (loss) of combined entity as if combination occurred at beginning of period		1,000				
Consideration transferred, acquisition-date fair value						$ 53,288
Cash transferred						53,288
Property, plant and equipment recognised as of acquisition date						67,549
Profit (loss) of acquiree since acquisition date		6,700				
Asset Retirement Obligations Recognized On Acquisition Date						$ 4,452
Spartan Energy Corp [Member]						
Cash flows from used in operations		35,000				
Revenue of acquiree since acquisition date		242,100				
Revenue of combined entity as if combination occurred at beginning of period		182,400				
Profit (loss) of combined entity as if combination occurred at beginning of period		35,000				
Equity interests of acquirer	$ 1,235,221					
Acquisition-related costs for transaction recognised separately from acquisition of assets and assumption of liabilities in business combination		1,300				
Consideration transferred, acquisition-date fair value	1,235,221					
Property, plant and equipment recognised as of acquisition date	1,401,686					
Profit (loss) of acquiree since acquisition date		45,100				
Asset Retirement Obligations Recognized On Acquisition Date	92,149					
Spartan Energy Corp [Member] | Vermilion Common Shares [Member]						
Equity interests of acquirer	27,900					

Stock issued during period Value as of the acquistion date	$ 1,200,000			
Par value per share | $ / shares	$ 44.30			
Wyoming [Member]				
Cash flows from used in operations		(100)	$ 0.1	
Revenue of acquiree since acquisition date		11,600		
Revenue of combined entity as if combination occurred at beginning of period		11,100		
Profit (loss) of combined entity as if combination occurred at beginning of period		(100)	$ 0.1	
Consideration transferred, acquisition-date fair value				$ 189,014
Cash transferred				189,014
Property, plant and equipment recognised as of acquisition date				284,333
Profit (loss) of acquiree since acquisition date		300		
Asset Retirement Obligations Recognized On Acquisition Date				$ 4,821
Shell E&P Ireland Limited [Member]				
Cash flows from used in operations		4,300		
Revenue of acquiree since acquisition date		1,300		
Revenue of combined entity as if combination occurred at beginning of period		15,200		
Profit (loss) of combined entity as if combination occurred at beginning of period		4,300		
Consideration transferred, acquisition-date fair value		$ (41,021)		
Incremental Working interest		1.50%		
Proportion of ownership interest in subsidiary		20.00%	20.00%	20.00%
Contingent consideration arrangements and indemnification assets recognised as of acquisition date		$ 290		
Maximum Contingent Consideration		9,100		€ 5.8
Cash transferred		40,805		
Property, plant and equipment recognised as of acquisition date		53,368		
Profit (loss) of acquiree since acquisition date		400		
Asset Retirement Obligations Recognized On Acquisition Date		1,565		
Minor [Member]				
Cash transferred		56,000		
Property, plant and equipment recognised as of acquisition date		147,400		
Asset Retirement Obligations Recognized On Acquisition Date		104,000		
Minor [Member] | Exploration and evaluation assets [member]				

Non-current assets recognised as of acquisition date	$ 28,600

Capital assets (Details) - CAD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure of Capital assets [Line Items]		
Beginning balance	$ 3,337,965	
Ending balance	5,316,873	$ 3,337,965
Property, plant and equipment	5,316,873	3,337,965
Capital assets [Member]		
Disclosure of Capital assets [Line Items]		
Beginning balance	3,337,965	3,433,245
Acquisitions	1,975,327	25,390
Additions	503,842	290,593
Increase in right-of-use assets	98,343	0
Transfers from exploration and evaluation assets	29,615	8,187
Depletion and depreciation	(605,994)	(479,698)
Changes in asset retirement obligations	(100,876)	(48,187)
Foreign exchange	78,651	108,435
Ending balance	5,316,873	3,337,965
Property, plant and equipment	3,337,965	3,337,965
Capital assets [Member] | Gross carrying amount [member]		
Disclosure of Capital assets [Line Items]		
Beginning balance	6,539,052	
Ending balance	9,202,604	6,539,052
Property, plant and equipment	9,202,604	6,539,052
Capital assets [Member] | Accumulated depreciation and amortisation [member]		
Disclosure of Capital assets [Line Items]		
Beginning balance	(3,201,087)	
Ending balance	(3,885,731)	(3,201,087)
Property, plant and equipment	$ (3,885,731)	$ (3,201,087)

Capital assets (Details 1) $ in Thousands	12 Months Ended Dec. 31, 2018 CAD ($)
Disclosure of Capital assets [Line Items]	
Depreciation	$ 19,358
Balance	133,946
Office space [Member]	
Disclosure of Capital assets [Line Items]	
Depreciation	9,119
Balance	62,279
Gas processing facilities [Member]	
Disclosure of Capital assets [Line Items]	
Depreciation	5,491
Balance	41,788
Oil storage facilities [Member]	
Disclosure of Capital assets [Line Items]	
Depreciation	2,728
Balance	20,758
Vehicles and equipment [Member]	
Disclosure of Capital assets [Line Items]	
Depreciation	2,020
Balance	$ 9,121

Exploration and evaluation assets (Details) - CAD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Exploration And Evaluation Assets [Line Items]		
Beginning balance	$ 3,337,965	
Ending balance	5,316,873	$ 3,337,965
Property, plant and equipment	5,316,873	3,337,965
Exploration and evaluation assets [member]		
Disclosure Of Exploration And Evaluation Assets [Line Items]		
Beginning balance	292,278	274,830
Acquisitions	28,572	2,247
Additions	14,372	29,856
Changes in asset retirement obligations	629	(30)
Transfers to capital assets	(29,615)	(8,187)
Depreciation	(5,942)	(11,727)
Foreign exchange	3,001	5,289
Ending balance	303,295	292,278
Property, plant and equipment	292,278	292,278
Exploration and evaluation assets [member] | Gross carrying amount [member]		
Disclosure Of Exploration And Evaluation Assets [Line Items]		
Beginning balance	354,615	
Ending balance	371,015	354,615
Property, plant and equipment	371,015	354,615
Exploration and evaluation assets [member] | Accumulated depreciation and amortisation [member]		
Disclosure Of Exploration And Evaluation Assets [Line Items]		
Beginning balance	(62,337)	
Ending balance	(67,720)	(62,337)
Property, plant and equipment	$ (67,720)	$ (62,337)

Asset retirement obligations (Details) - CAD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Asset Retirement Obligations [Line Items]		
Beginning balance	$ 517,180	$ 525,022
Additional obligations recognized	211,580	3,273
Changes in estimated abandonment timing and costs	(98,158)	(48,904)
Obligations settled	(15,765)	(9,334)
Accretion	31,219	26,971
Changes in discount rates	(6,646)	(2,586)
Foreign exchange	10,754	22,738
Ending balance	$ 650,164	$ 517,180

Asset retirement obligations (Details 1) - Provision for decommissioning, restoration and rehabilitation costs [member]	Dec. 31, 2018	Dec. 31, 2017
CANADA		
Disclosure Of Asset Retirement Obligations [Line Items]		
Discount rate used in current measurement of fair value less costs of disposal	2.20%	2.30%
FRANCE		
Disclosure Of Asset Retirement Obligations [Line Items]		
Discount rate used in current measurement of fair value less costs of disposal	1.60%	1.80%
NETHERLANDS		
Disclosure Of Asset Retirement Obligations [Line Items]		
Discount rate used in current measurement of fair value less costs of disposal	0.40%	0.50%
GERMANY		
Disclosure Of Asset Retirement Obligations [Line Items]		
Discount rate used in current measurement of fair value less costs of disposal	0.90%	1.00%
IRELAND		
Disclosure Of Asset Retirement Obligations [Line Items]		
Discount rate used in current measurement of fair value less costs of disposal	1.60%	0.40%
AUSTRALIA		
Disclosure Of Asset Retirement Obligations [Line Items]		
Discount rate used in current measurement of fair value less costs of disposal	2.60%	2.90%
UNITED STATES		
Disclosure Of Asset Retirement Obligations [Line Items]		
Discount rate used in current measurement of fair value less costs of disposal	2.70%	2.40%

Asset retirement obligations (Details Textual) - CAD ($) $ in Millions	12 Months Ended Dec. 31, 2019	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Asset Retirement Obligations [Line Items]			
Credit Risk Rate Used In Determining Other Provisions		4.00%	3.80%
Increase decrease in discount rate, asset retirement obligations		0.50%	
Increase (Decrease) in Asset Retirement Obligations		$ 55.0	
Scenerio Forecasts [Member]			
Disclosure Of Asset Retirement Obligations [Line Items]			
Increase (Decrease) in Asset Retirement Obligations	$ 25.0		
Two Thousand Twenty And Two Thousand Seventy Eight [Member]			
Disclosure Of Asset Retirement Obligations [Line Items]			
Asset retirement obligations based on a total undiscounted future liability		2,600.0	$ 1,600.0
Two Thousand Twenty Nine And Two Thousand Thirty Six [Member]			
Disclosure Of Asset Retirement Obligations [Line Items]			
Asset retirement obligations based on a total undiscounted future liability		600.0	
Two Thousand Forty Seven And Two Thousand Fifty Five [Member]			
Disclosure Of Asset Retirement Obligations [Line Items]			
Asset retirement obligations based on a total undiscounted future liability		600.0	
Two Thousand Sixty Three And Two Thousand Sixty Eight [Member]			
Disclosure Of Asset Retirement Obligations [Line Items]			
Asset retirement obligations based on a total undiscounted future liability		$ 900.0	
Bottom of range [member]			
Disclosure Of Asset Retirement Obligations [Line Items]			
Inflation rates used in determining the cash flow estimates		0.50%	0.60%
Top of range [member]			
Disclosure Of Asset Retirement Obligations [Line Items]			
Inflation rates used in determining the cash flow estimates		2.90%	2.20%

Derivative instruments (Details) - CAD ($) $ in Thousands	12 Months Ended Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Derivative instruments [Abstract]				
Fair value of contracts, beginning of year	$ (70,713)	$ (69,651)		
Reversal of opening contracts settled during the year	57,719	43,324		
Assumed in acquisitions			$ (274)	$ 0
Realized (loss) gain on contracts settled during the year	(111,258)	4,721		
Unrealized gain (loss) during the year on contracts outstanding at the end of the year	51,607	(44,386)		
Net receipt from counterparties on contract settlements during the year	111,258	(4,721)		
Fair value of contracts, end of year	38,339	(70,713)		
Current derivative asset			95,667	17,988
Current derivative liability			(41,016)	(78,905)
Non-current derivative asset			1,215	2,552
Non-current derivative liability			(17,527)	(12,348)
Fair value of contracts, end of year	$ (70,713)	$ (70,713)	$ 38,339	$ (70,713)

Derivative instruments (Details 1) - CAD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Derivative instruments [Abstract]		
Realized loss (gain) on contracts settled during the year	$ 111,258	$ (4,721)
Reversal of opening contracts settled during the year	(57,719)	(43,324)
Unrealized (gain) loss on contracts outstanding at the end of the year	(51,607)	44,386
Loss (gain) on derivative instruments	$ 1,932	$ (3,659)

Leases (Details) - CAD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of leases [Line Items]		
Total lease payments	$ 157,717	$ 24,903
Amounts representing interest	(24,583)	(3,526)
Present value of net minimum lease payments	133,134	21,377
Current portion of finance lease obligation	(24,945)	(5,570)
Non-current portion of finance lease obligation	108,189	15,807
Not later than one year [member]		
Disclosure Of leases [Line Items]		
Total lease payments	30,641	6,680
Later than one year and not later than three years [member]		
Disclosure Of leases [Line Items]		
Total lease payments	50,024	10,207
Later than four years and not later than five years [member]		
Disclosure Of leases [Line Items]		
Total lease payments	34,313	4,665
Later than five years [member]		
Disclosure Of leases [Line Items]		
Total lease payments	$ 42,739	$ 3,351

Leases (Details Textual) $ in Millions, $ in Millions	12 Months Ended Dec. 31, 2018 CAD ($)	Dec. 31, 2017 USD ($)
Disclosure of leases [Abstract]		
Interest expense on lease liabilities	$ 7.2	
Lease liabilities	$ 28.0	$ 34.3

Taxes (Details) - CAD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017
Deferred Tax Assets [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	$ 219,411	$ 80,324
Deferred Tax Liabilities [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	(318,134)	(253,108)
Non-capital losses [Member] | Deferred Tax Assets [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	487,398	342,202
Non-capital losses [Member] | Deferred Tax Liabilities [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	57,785	34,703
Capital assets [Member] | Deferred Tax Assets [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	(296,591)	(294,178)
Capital assets [Member] | Deferred Tax Liabilities [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	(319,553)	(259,236)
Asset retirement obligations [Member] | Deferred Tax Assets [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	38,429	28,056
Asset retirement obligations [Member] | Deferred Tax Liabilities [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	(51,031)	(27,868)
Derivative contracts [Member] | Deferred Tax Assets [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	(11,937)	10,164
Derivative contracts [Member] | Deferred Tax Liabilities [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	0	11,386
Unrealized foreign exchange [Member] | Deferred Tax Assets [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	(1,873)	(7,927)
Unrealized foreign exchange [Member] | Deferred Tax Liabilities [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	(10,715)	(13,355)
Other deferred tax assets [Member] | Deferred Tax Assets [Member]		
Disclosure of income tax [Line Items]		
Deferred tax liability (asset)	3,985	2,007
Other deferred tax liabilities [Member] | Deferred Tax Liabilities [Member]		
Disclosure of income tax [Line Items]		

Deferred tax liability (asset)	$ 5,380	$ 1,262

Taxes (Details 1) - CAD ($) $ in Thousands		1 Months Ended	12 Months Ended	
		Dec. 31, 2020	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Taxes [Abstract]				
Earnings before income taxes			$ 354,698	$ 124,482
Canadian corporate tax rate		22.55%	27.00%	27.00%
Expected tax expense			$ 95,768	$ 33,610
Petroleum resource rent tax rate (PRRT) differential	[1]		5,349	3,531
Foreign tax rate differentials	[1],[2]		3,086	7,146
Equity based compensation expense			13,883	10,343
Amended returns and changes to estimated tax pools and tax positions			(873)	(17,246)
Statutory rate changes and the estimated reversal rates associated with temporary differences	[3]		0	(16,449)
(Re-recognition) de-recognition of deferred tax assets			(26,931)	44,608
Adjustment for uncertain tax positions			8,080	2,191
Gain on business combinations			(28,812)	0
Other non-deductible items			13,498	(5,510)
Provision for income taxes			$ 83,048	$ 62,224

[1] In Australia, current taxes include both corporate income tax rates and PRRT. Corporate income tax rates were applied at a rate of 30% and PRRT was applied at a rate of 40%.

[2] The applicable tax rates for 2018 were: 34.4% in France, 50.0% in the Netherlands, 30.2% in Germany, 25.0% in Ireland, and 21.0% in the United States.

[3] On December 22, 2017, the Tax Cuts and Jobs Act was signed into law in the United States reducing the U.S. federal corporate income tax rate from 35% to 21%. On December 21, 2017, the French Parliament approved the Finance Bill for 2018. The Finance Bill for 2018 provides for a progressive decrease of the French standard corporate income tax rate from 34.43% to 25.825% by 2022. On December 18, 2018, the Dutch government approved the 2019 Tax Plan. The Bill provides for reduced corporate tax rates from 25.0% to 20.5% by 2021, with the first reduction planned for 2020 to 22.55%. Due to the tax regime applicable to natural gas producers in the Netherlands, the reduction to the corporate tax rate is not expected to have a material impact to Vermilion taxes in the Netherlands.

Taxes (Details Textual) - CAD ($) $ in Millions		1 Months Ended			12 Months Ended	
	Dec. 31, 2022	Dec. 31, 2021	Dec. 31, 2020	Dec. 22, 2017	Dec. 31, 2018	Dec. 31, 2017
Disclosure of income tax [Line Items]						
Applicable tax rate			22.55%		27.00%	27.00%
Unused tax losses for which no deferred tax asset recognised					$ 2,600.0	$ 2,000.0
Deductible temporary differences for which no deferred tax asset is recognised					90.6	145.6
Temporary differences associated with investments in subsidiaries, branches and associates and interests in joint arrangements for which deferred tax liabilities have not been recognised					500.0	400.0
Vermilion's Canada Segment [Member]						
Disclosure of income tax [Line Items]						
Deductible temporary differences, unused tax losses and unused tax credits expired					1,100.0	500.0
Vermilion's Ireland Segment [Member]						
Disclosure of income tax [Line Items]						
Deductible temporary differences, unused tax losses and unused tax credits expired					$ 1,300.0	$ 1,300.0
Bottom of range [member] | Vermilion's Canada Segment [Member]						
Disclosure of income tax [Line Items]						
Description of expiry date of deductible temporary differences, unused tax losses and unused tax credits					2025	
Top of range [member] | Vermilion's Canada Segment [Member]						
Disclosure of income tax [Line Items]						
Description of expiry date of deductible temporary differences, unused tax losses and unused tax credits					2038	
FRANCE						
Disclosure of income tax [Line Items]						
Applicable tax rate					34.40%	
NETHERLANDS						
Disclosure of income tax [Line Items]						
Applicable tax rate					50.00%	
GERMANY						
Disclosure of income tax [Line Items]						
Applicable tax rate					30.20%	
IRELAND						
Disclosure of income tax [Line Items]						
Applicable tax rate					25.00%	

UNITED STATES				
Disclosure of income tax [Line Items]				
Applicable tax rate				21.00%
Corporate Income tax [Member]				
Disclosure of income tax [Line Items]				
Applicable tax rate		20.50%		25.00%
Corporate Income tax [Member] | AUSTRALIA				
Disclosure of income tax [Line Items]				
Applicable tax rate				30.00%
Petroleum Resource Rent Tax [Member] | AUSTRALIA				
Disclosure of income tax [Line Items]				
Applicable tax rate				40.00%
United states Corporate Income tax [Member]				
Disclosure of income tax [Line Items]				
Applicable tax rate			35.00%	21.00%
FrenchCorporate Income tax [Member]				
Disclosure of income tax [Line Items]				
Applicable tax rate	25.825%			34.43%

Long-term debt (Details) - CAD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Long-Term Debt [Abstract]		
Revolving credit facility	$ 1,392,206	$ 899,595
Senior unsecured notes	404,001	370,735
Long-term debt	$ 1,796,207	$ 1,270,330

Long-term debt (Details 1) - CAD ($) $ in Thousands		12 Months Ended	
		Dec. 31, 2018	Dec. 31, 2017
Disclosure of Long-Term Debt [Line Items]			
Beginning balance		$ 1,270,330	$ 1,362,192
Borrowings (repayments) on the revolving credit facility		251,155	(450,646)
Issuance of senior unsecured notes		0	391,906
Assumed on acquisitions	[1]	188,496	0
Amortization of transaction costs and prepaid interest		2,286	2,012
Foreign exchange		83,940	(35,134)
Ending balance		$ 1,796,207	$ 1,270,330

[1] Pursuant to the acquisitions described in Note 5 (Business Combinations), Vermilion assumed the credit facilities of the acquired companies and immediately extinguished them following the respective acquisitions using proceeds from Vermilion's revolving credit facility.

Long-term debt (Details 2) - Revolving Credit Facilities [Member] - CAD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017
Disclosure of Long-Term Debt [Line Items]		
Total facility amount	$ 1,800,000	$ 1,400,000
Amount drawn	(1,392,206)	(899,595)
Letters of credit outstanding	(15,400)	(7,400)
Unutilized capacity	$ 392,394	$ 493,005

Long-term debt (Details 3) - Limit	Dec. 31, 2018	Dec. 31, 2017
Disclosure of Long-Term Debt [Line Items]		
Consolidated total debt to consolidated EBITDA	1.72	1.87
Consolidated total senior debt to consolidated EBITDA	1.34	1.30
Consolidated total senior debt to total capitalization	30.00%	32.00%
Top of range [member]		
Disclosure of Long-Term Debt [Line Items]		
Consolidated total debt to consolidated EBITDA	4.0	
Consolidated total senior debt to consolidated EBITDA	3.5	
Consolidated total senior debt to total capitalization	55.00%	

Long-term debt (Details 4)	12 Months Ended Dec. 31, 2018
2020 [Member]	
Disclosure of Long-Term Debt [Line Items]	
Redemption price Percentage of senior unsecured notes	104.219%
2021 [Member]	
Disclosure of Long-Term Debt [Line Items]	
Redemption price Percentage of senior unsecured notes	102.813%
2022 [Member]	
Disclosure of Long-Term Debt [Line Items]	
Redemption price Percentage of senior unsecured notes	101.406%
2023 and thereafter [Member]	
Disclosure of Long-Term Debt [Line Items]	
Redemption price Percentage of senior unsecured notes	100.00%

Long-term debt (Details Textual) - USD ($) $ in Millions	Mar. 15, 2020	12 Months Ended Dec. 31, 2018	Mar. 13, 2017
Disclosure of Long-Term Debt [Line Items]			
Borrowings Repayment Description Prior Maturity	Prior to March 15, 2020, Vermilion may redeem up to 35% of the original principal amount of the senior unsecured notes with the proceeds of certain equity offerings by the Company at a redemption price of 105.625% of the principal amount plus any accrued and unpaid interest to the applicable redemption date. Prior to March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at a price equal to 100% of the principal amount of the senior unsecured notes, plus an applicable premium and any accrued and unpaid interest. On or after March 15, 2020, Vermilion may redeem some or all of the senior unsecured notes at the redemption prices set forth in the following table plus any accrued and unpaid interest.		
Unsecured notes [Member]			
Disclosure of Long-Term Debt [Line Items]			
Notional amount			$ 300.0
Borrowings, interest rate			5.625%
Borrowings Repayment Description Prior Maturity		March 15, 2025	

Shareholders' capital (Details) - CAD ($) shares in Thousands, $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Shareholder's Capital [Line Items]		
Balance, beginning of year	$ 2,650,706	$ 2,452,722
Balance at January 1 (shares)	122,119	118,263
Shares issued for acquisition	$ 1,234,676	$ 0
Shares issued for acquisition (shares)	27,883	0
Shares issued for the Dividend Reinvestment Plan	$ 49,051	$ 110,493
Vesting of equity based awards (shares)	1,025	1,060
Share-settled dividends on vested equity based awards (shares)	184	170
Balance, end of year	$ 4,008,828	$ 2,650,706
Balance at December 31 (shares)	152,704	122,119
Equity based compensation [Member]		
Disclosure Of Shareholder's Capital [Line Items]		
Shares issued for equity based compensation (shares)	314	197
Dividend reinvestment plan [Member]		
Disclosure Of Shareholder's Capital [Line Items]		
Shares issued for the Dividend Reinvestment Plan (shares)	1,179	2,429
Issued capital [member]		
Disclosure Of Shareholder's Capital [Line Items]		
Vesting of equity based awards	$ 54,057	$ 69,743
Shares issued for equity based compensation	12,565	9,270
Share-settled dividends on vested equity based awards	$ 7,773	$ 8,478

Shareholders' capital (Details Textual) - CAD ($) $ / shares in Units, $ in Millions	1 Months Ended	12 Months Ended	
	Feb. 27, 2019	Dec. 31, 2018	Dec. 31, 2017
Disclosure of Shareholder's Capital [Abstract]			
Dividends proposed or declared before financial statements authorised for issue but not recognised as distribution to owners	$ 70.3		
Dividends proposed or declared before financial statements authorised for issue but not recognised as distribution to owners per share	$ 0.230		
Dividends paid, ordinary shares		$ 388.1	$ 311.4
Dividends paid, ordinary shares per share		$ 2.72	$ 2.58

Capital disclosures (Details) $ in Thousands	Dec. 31, 2018 CAD ($)	Dec. 31, 2017 CAD ($)	Dec. 31, 2016 CAD ($)
Disclosure Of Capital Disclosures [Abstract]			
Long-term debt	$ 1,796,207	$ 1,270,330	$ 1,362,192
Current liabilities	563,199	363,306	
Current assets	(429,877)	(261,846)	
Net debt	$ 1,929,529	$ 1,371,790	
Ratio of net debt to fund flows from operations	2.30	2.28	

Capital disclosures (Details Textual)	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Capital Disclosures [Line Items]		
Ratio of net debt to funds from operations	2.30	2.28
Top of range [member]		
Disclosure Of Capital Disclosures [Line Items]		
Ratio of net debt to funds from operations	1.5	

Equity based compensation (Details) - Vermilion incentive plan [Member] - Awards Awards in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Equity Based Compensation [Line Items]		
Opening balance	1,685	1,738
Granted	932	563
Vested	(520)	(539)
Forfeited	(166)	(77)
Closing balance	1,931	1,685

Equity based compensation (Details Textual)	12 Months Ended Dec. 31, 2018 CAD ($) Awards	Dec. 31, 2017 CAD ($) Awards	Dec. 31, 2016 Awards
Disclosure Of Equity Based Compensation [Line Items]			
Expense from share-based payment transactions with employees	$ 60,746,000	$ 61,579,000	
Vermilion incentive plan [Member]			
Disclosure Of Equity Based Compensation [Line Items]			
Weighted average fair value at measurement date, other equity instruments granted	$ 40.57	$ 49.44	
Performance factor (ratio)	1.9	1.9	
Annual forfeiture rate share options granted	4.60%	4.40%	
Expense from share-based payment transactions with employees	$ 48,200,000	$ 52,300,000	
Number of other equity instruments outstanding in share-based payment arrangement | Awards	1,931,000	1,685,000	1,738,000
Five-Year Compensation Arrangement [member]			
Disclosure Of Equity Based Compensation [Line Items]			
Number of other equity instruments outstanding in share-based payment arrangement | Awards	36,845		

Per share amounts (Details) - CAD ($) $ / shares in Units, shares in Thousands, $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Per Share Amounts [Abstract]		
Net earnings	$ 271,650	$ 62,258
Basic weighted average shares outstanding ('000s)	140,619	120,582
Dilutive impact of equity based compensation ('000s)	1,716	1,826
Diluted weighted average shares outstanding ('000s)	142,335	122,408
Basic earnings per share	$ 1.93	$ 0.52
Diluted earnings per share	$ 1.91	$ 0.51

Financial instruments (Details) - CAD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017
Derivative liabilities [Member]		
Disclosure of detailed information about financial instruments [line items]		
FINANCIAL LIABILITIES, Carrying Value	$ (58,543)	$ (91,253)
FINANCIAL LIABILITIES, Fair Value	(58,543)	(91,253)
Dividends payable [Member]		
Disclosure of detailed information about financial instruments [line items]		
FINANCIAL LIABILITIES, Carrying Value	(35,122)	(26,256)
FINANCIAL LIABILITIES, Fair Value	(35,122)	(26,256)
Accounts payable and accrued liabilities [Member]		
Disclosure of detailed information about financial instruments [line items]		
FINANCIAL LIABILITIES, Carrying Value	(449,651)	(219,084)
FINANCIAL LIABILITIES, Fair Value	(449,651)	(219,084)
Long-term debt [Member]		
Disclosure of detailed information about financial instruments [line items]		
FINANCIAL LIABILITIES, Carrying Value	(1,796,207)	(1,270,330)
FINANCIAL LIABILITIES, Fair Value	(1,781,809)	(1,274,891)
Cash and cash equivalents [Member]		
Disclosure of detailed information about financial instruments [line items]		
FINANCIAL ASSETS, Carrying Value	26,809	46,561
FINANCIAL ASSETS, Fair Value	26,809	46,561
Derivative assets [Member]		
Disclosure of detailed information about financial instruments [line items]		
FINANCIAL ASSETS, Carrying Value	96,882	20,540
FINANCIAL ASSETS, Fair Value	96,882	20,540
Loans and receivables [Member]		
Disclosure of detailed information about financial instruments [line items]		
FINANCIAL ASSETS, Carrying Value	260,322	165,760
FINANCIAL ASSETS, Fair Value	$ 260,322	$ 165,760

Financial instruments (Details 1) - CAD ($) $ in Thousands	12 Months Ended Dec. 31, 2018	Dec. 31, 2017
Currency risk increase [Member] | Euro [Member]		
Disclosure of detailed information about financial instruments [line items]		
Increase or decrease to net earnings before tax due to change in fair value of financial instruments	$ (2,205)	$ (4,607)
Currency risk increase [Member] | US dollar [Member]		
Disclosure of detailed information about financial instruments [line items]		
Increase or decrease to net earnings before tax due to change in fair value of financial instruments	2,981	2,239
Currency risk decrease [Member] | Euro [Member]		
Disclosure of detailed information about financial instruments [line items]		
Increase or decrease to net earnings before tax due to change in fair value of financial instruments	2,205	4,607
Currency risk decrease [Member] | US dollar [Member]		
Disclosure of detailed information about financial instruments [line items]		
Increase or decrease to net earnings before tax due to change in fair value of financial instruments	(2,981)	(2,239)
Commodity price risk increase [Member] | Euro [Member]		
Disclosure of detailed information about financial instruments [line items]		
Increase or decrease to net earnings before tax due to change in fair value of financial instruments	(36,508)	(32,642)
Commodity price risk increase [Member] | US dollar [Member]		
Disclosure of detailed information about financial instruments [line items]		
Increase or decrease to net earnings before tax due to change in fair value of financial instruments	(18,421)	(21,616)
Commodity price risk decrease [Member] | Euro [Member]		
Disclosure of detailed information about financial instruments [line items]		
Increase or decrease to net earnings before tax due to change in fair value of financial instruments	33,005	25,321
Commodity price risk decrease [Member] | US dollar [Member]		
Disclosure of detailed information about financial instruments [line items]		
Increase or decrease to net earnings before tax due to change in fair value of financial instruments	$ 17,351	$ 19,845

Financial instruments (Details 2) - CAD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017
1 month		
Disclosure of detailed information about financial instruments [line items]		
Non-derivative financial liabilities, undiscounted cash flows	$ 167,491	$ 99,092
1 month to 3 months		
Disclosure of detailed information about financial instruments [line items]		
Non-derivative financial liabilities, undiscounted cash flows	306,927	138,273
3 months to 1 year		
Disclosure of detailed information about financial instruments [line items]		
Non-derivative financial liabilities, undiscounted cash flows	10,355	7,974
1 year to 5 years		
Disclosure of detailed information about financial instruments [line items]		
Non-derivative financial liabilities, undiscounted cash flows	$ 1,472,087	$ 912,306

Financial instruments (Details Textual) - CAD ($) $ in Millions	Dec. 31, 2018	Dec. 31, 2017
Disclosure of detailed information about financial instruments [line items]		
Maximum exposure to credit risk	$ 357.2	$ 186.3
Percentage of trade and other current receivables	0.70%	0.70%

Related party disclosures (Details) $ in Thousands	12 Months Ended Dec. 31, 2018 CAD ($) Awards	Dec. 31, 2017 CAD ($) Number
Disclosure Of Related Party Disclosures [Line Items]		
Short-term benefits	$ 6,018	$ 5,183
Share-based payments	16,309	20,135
Key management personnel compensation	$ 22,327	$ 25,318
Key management personnel [member]		
Disclosure Of Related Party Disclosures [Line Items]		
Number of individuals included in the above amounts	18	20

Related party disclosures (Details Textual) - CAD ($) $ in Millions	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Related Party Disclosures [Abstract]		
Income from subleasing right-of-use assets	$ 0.2	$ 0.2

Supplemental information (Details) - CAD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Increase Decrease In Working Capital [Abstract]		
Accounts receivable	$ (94,562)	$ (34,041)
Crude oil inventory	(10,646)	(2,577)
Prepaid expenses	(4,896)	(1,884)
Accounts payable and accrued liabilities	230,567	37,527
Income taxes payable	(1,651)	2,842
Working capital assumed from acquisitions	(58,841)	0
Initial recognition of IFRS 16 liability	(10,483)	0
Foreign exchange	(873)	(795)
Changes in non-cash working capital	48,615	1,072
Changes in non-cash operating working capital	(6,876)	665
Changes in non-cash investing working capital	55,491	407
Changes in non-cash working capital	$ 48,615	$ 1,072

Supplemental information (Details 1) - CAD ($) $ in Thousands	Dec. 31, 2018	Dec. 31, 2017	Dec. 31, 2016
Disclosure Of Supplemental Information [Line Items]			
Cash on deposit with financial institutions	$ 26,604	$ 46,229	
Guaranteed investment certificates	205	332	
Cash and cash equivalents	$ 26,809	$ 46,561	$ 62,775

Supplemental information (Details 2) - CAD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2018	Dec. 31, 2017
Disclosure Of Supplemental Information [Line Items]		
Short-term employee benefits expense	$ 108,591	$ 85,531
Operating expense [Member]		
Disclosure Of Supplemental Information [Line Items]		
Short-term employee benefits expense	66,095	48,823
General and administration expense [Member]		
Disclosure Of Supplemental Information [Line Items]		
Short-term employee benefits expense	$ 42,496	$ 36,708

Supplemental information (Details 3) - 12 months ended Dec. 31, 2018	CAD ($)	USD ($)	Awards	mmbtu_d	$ / CallPrice_mmbtu	€ / CallPrice_mmbtu	$ / CallPrice_mmbtu
Derivative, contract period	Nov 2018 - Mar 2019	Nov 2018 - Mar 2019					
Description of presentation currency	USD	USD					
Derivative, bought put volume			0				
Derivative,weighted average bought put | $ / CallPrice_mmbtu					0		
Derivative, sold call volume			0				
Derivative,weighted average sold call					0		4.00
Derivative, sold put volume			0				
Derivative,weighted average sold put | $ / CallPrice_mmbtu					0		
Derivative, swap volume			5,000				
Derivative,weighted average swap | $ / CallPrice_mmbtu					(1.46)		
European Gas NBP [Member] | Purchased call options [member]							
Derivative, contract period	Oct 2018 - Mar 2019	Oct 2018 - Mar 2019					
Description of presentation currency	EUR	EUR					
Derivative, bought put volume | mmbtu_d				0			
Derivative,weighted average bought put | $ / CallPrice_mmbtu					0		
Derivative, sold call volume			12,327				
Derivative,weighted average sold call | € / CallPrice_mmbtu						6.28	
Derivative, sold put volume			0				
Derivative,weighted average sold put | $ / CallPrice_mmbtu					0		
Derivative, swap volume			0				
Derivative,weighted average swap | $ / CallPrice_mmbtu					0		
Swap Contract One [Member] | Crude oil dated brent [Member]							
Derivative, contract period	Jan 2019 - Dec 2019	Jan 2019 - Dec 2019					
Description of presentation currency	CAD	CAD					
Derivative, bought put volume			0				

Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			1,350	
Derivative,weighted average swap | $ / CallPrice_mmbtu				91.76
Swap Contract One [Member] | Crude oil west texas intermediate [Member]				
Derivative, contract period	Jan 2019 - Dec 2019	Jan 2019 - Dec 2019		
Description of presentation currency	CAD	CAD		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			1,050	
Derivative,weighted average swap | $ / CallPrice_mmbtu				81.41
Swap Contract One [Member] | North American Gas AECO [Member]				
Derivative, contract period	Dec 2018 - Mar 2019	Dec 2018 - Mar 2019		
Description of presentation currency	CAD	CAD		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0

Derivative, swap volume			2,500	
Derivative,weighted average swap | $ / CallPrice_mmbtu				2.41
Swap Contract One [Member] | North American Gas AECO basis [Member]				
Derivative, contract period	Jan 2019 - Jun 2020	Jan 2019 - Jun 2020		
Description of presentation currency	USD	USD		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			2,500	
Derivative,weighted average swap | $ / CallPrice_mmbtu				(0.93)
Swap Contract One [Member] | North American Gas NYMEX HH [Member]				
Derivative, contract period	Jan 2019 - Mar 2019	Jan 2019 - Mar 2019		
Description of presentation currency	USD	USD		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			5,000	
Derivative,weighted average swap | $ / CallPrice_mmbtu				4.00
Swap Contract One [Member] | European Gas NBP [Member]				
Derivative, contract period	Oct 2018 - Mar 2019	Oct 2018 - Mar 2019		
Description of presentation currency	EUR	EUR		

Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			4,913	
Derivative,weighted average swap | $ / CallPrice_mmbtu				7.92
Swap Contract One [Member] | European Gas TTF [Member]				
Derivative, contract period	Oct 2017 - Dec 2019	Oct 2017 - Dec 2019		
Description of presentation currency	EUR	EUR		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			7,370	
Derivative,weighted average swap | $ / CallPrice_mmbtu				4.87
Swap Contract One [Member] | European Gas cross currency interest rate [Member]				
Derivative interest maturity period	Jan 2019	Jan 2019		
Proceeds from sales or maturity of financial instruments, classified as investing activities | $		$ 1,018,563,000		
London Interbank Offered Rate	1.70%	1.70%		
Purchase of financial instruments, classified as investing activities | $	$ 1,354,900,000			
Canadian Dollar Offered Rate	1.02%	1.02%		
Swap Contract One [Member] | North American Gas Chicago NGI [Member]				
Derivative, contract period	Dec 2018 - Mar 2019	Dec 2018 - Mar 2019		
Description of presentation currency	USD	USD		
Derivative, bought put volume			0	

Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			5,000	
Derivative,weighted average swap | $ / CallPrice_mmbtu				4.40
Swap Contract One [Member] | North American Gas Socal Border [Member]				
Derivative, contract period [1]	Jan 2019	Jan 2019		
Description of presentation currency [1]	USD	USD		
Derivative, bought put volume [1]			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu [1]				0
Derivative, sold call volume [1]			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu [1]				0
Derivative, sold put volume [1]			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu [1]				0
Derivative, swap volume [1]			10,000	
Derivative,weighted average swap | $ / CallPrice_mmbtu [1]				5.50
3 Way Collar One | Crude oil dated brent [Member]				
Derivative, contract period	Sep 2018 - Jun 2019	Sep 2018 - Jun 2019		
Description of presentation currency	CAD	CAD		
Derivative, bought put volume			2,500	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				91.20
Derivative, sold call volume			2,500	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				98.63
Derivative, sold put volume			2,500	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				76.00
Derivative, swap volume			0	

Derivative,weighted average swap | $ / CallPrice_mmbtu					0	
3 Way Collar One | Crude oil west texas intermediate [Member]						
Derivative, contract period	Jan 2019 - Dec 2019	Jan 2019 - Dec 2019				
Description of presentation currency	USD	USD				
Derivative, bought put volume			250			
Derivative,weighted average bought put | $ / CallPrice_mmbtu					70.00	
Derivative, sold call volume			250			
Derivative,weighted average sold call | $ / CallPrice_mmbtu					80.25	
Derivative, sold put volume			250			
Derivative,weighted average sold put | $ / CallPrice_mmbtu					60.00	
Derivative, swap volume			0			
Derivative,weighted average swap | $ / CallPrice_mmbtu					0	
3 Way Collar One | European Gas NBP [Member]						
Derivative, contract period	Jan 2019 - Dec 2019	Jan 2019 - Dec 2019				
Description of presentation currency	EUR	EUR				
Derivative, bought put volume | mmbtu_d				17,197		
Derivative,weighted average bought put | $ / CallPrice_mmbtu					4.97	
Derivative, sold call volume			17,197			
Derivative,weighted average sold call | € / CallPrice_mmbtu						5.65
Derivative, sold put volume			17,197			
Derivative,weighted average sold put | $ / CallPrice_mmbtu					3.79	
Derivative, swap volume			0			
Derivative,weighted average swap | $ / CallPrice_mmbtu					0	
3 Way Collar One | European Gas TTF [Member]						
Derivative, contract period	Oct 2017 - Dec 2019	Oct 2017 - Dec 2019				
Description of presentation currency	EUR	EUR				
Derivative, bought put volume			7,370			

Derivative,weighted average bought put | $ / CallPrice_mmbtu					4.59	
Derivative, sold call volume			7,370			
Derivative,weighted average sold call | $ / CallPrice_mmbtu					5.42	
Derivative, sold put volume			7,370			
Derivative,weighted average sold put | $ / CallPrice_mmbtu					2.93	
Derivative, swap volume			0			
Derivative,weighted average swap | $ / CallPrice_mmbtu					0	
3 Way Collar Two | Crude oil dated brent [Member]						
Derivative, contract period	Aug 2018 - Jun 2019	Aug 2018 - Jun 2019				
Description of presentation currency	USD	USD				
Derivative, bought put volume			500			
Derivative,weighted average bought put | $ / CallPrice_mmbtu					66.92	
Derivative, sold call volume			500			
Derivative,weighted average sold call | $ / CallPrice_mmbtu					80.00	
Derivative, sold put volume			500			
Derivative,weighted average sold put | $ / CallPrice_mmbtu					55.00	
Derivative, swap volume			0			
Derivative,weighted average swap | $ / CallPrice_mmbtu					0	
3 Way Collar Two | European Gas NBP [Member]						
Derivative, contract period	Jan 2019 - Dec 2020	Jan 2019 - Dec 2020				
Description of presentation currency	EUR	EUR				
Derivative, bought put volume | mmbtu_d				7,370		
Derivative,weighted average bought put | $ / CallPrice_mmbtu					4.96	
Derivative, sold call volume			7,370			
Derivative,weighted average sold call | € / CallPrice_mmbtu						5.76
Derivative, sold put volume			7,370			
Derivative,weighted average sold put | $ / CallPrice_mmbtu					3.74	
Derivative, swap volume			0			

Derivative,weighted average swap | $ / CallPrice_mmbtu					0
3 Way Collar Two | European Gas TTF [Member]					
Derivative, contract period	Jan 2018 - Dec 2019	Jan 2018 - Dec 2019			
Description of presentation currency	EUR	EUR			
Derivative, bought put volume			3,685		
Derivative,weighted average bought put | $ / CallPrice_mmbtu					4.74
Derivative, sold call volume			3,685		
Derivative,weighted average sold call | $ / CallPrice_mmbtu					5.52
Derivative, sold put volume			3,685		
Derivative,weighted average sold put | $ / CallPrice_mmbtu					3.13
Derivative, swap volume			0		
Derivative,weighted average swap | $ / CallPrice_mmbtu					0
3 Way Collar Three | Crude oil dated brent [Member]					
Derivative, contract period	Jan 2019 - Dec 2019	Jan 2019 - Dec 2019			
Description of presentation currency	USD	USD			
Derivative, bought put volume			500		
Derivative,weighted average bought put | $ / CallPrice_mmbtu					70.00
Derivative, sold call volume			500		
Derivative,weighted average sold call | $ / CallPrice_mmbtu					80.00
Derivative, sold put volume			500		
Derivative,weighted average sold put | $ / CallPrice_mmbtu					60.00
Derivative, swap volume			0		
Derivative,weighted average swap | $ / CallPrice_mmbtu					0
3 Way Collar Three | European Gas NBP [Member]					
Derivative, contract period	Jan 2020 - Dec 2020	Jan 2020 - Dec 2020			
Description of presentation currency	EUR	EUR			
Derivative, bought put volume | mmbtu_d				19,654	

Derivative,weighted average bought put | $ / CallPrice_mmbtu				5.10	
Derivative, sold call volume			19,654		
Derivative,weighted average sold call | € / CallPrice_mmbtu					5.92
Derivative, sold put volume			19,654		
Derivative,weighted average sold put | $ / CallPrice_mmbtu				4.01	
Derivative, swap volume			0		
Derivative,weighted average swap | $ / CallPrice_mmbtu				0	
3 Way Collar Three | European Gas TTF [Member]					
Derivative, contract period	Jan 2019 - Dec 2019	Jan 2019 - Dec 2019			
Description of presentation currency	EUR	EUR			
Derivative, bought put volume			12,284		
Derivative,weighted average bought put | $ / CallPrice_mmbtu				5.05	
Derivative, sold call volume			12,284		
Derivative,weighted average sold call | $ / CallPrice_mmbtu				5.72	
Derivative, sold put volume			12,284		
Derivative,weighted average sold put | $ / CallPrice_mmbtu				3.69	
Derivative, swap volume			0		
Derivative,weighted average swap | $ / CallPrice_mmbtu				0	
3 Way Collar Four | European Gas TTF [Member]					
Derivative, contract period	Jan 2020 - Dec 2020	Jan 2020 - Dec 2020			
Description of presentation currency	EUR	EUR			
Derivative, bought put volume			7,370		
Derivative,weighted average bought put | $ / CallPrice_mmbtu				5.37	
Derivative, sold call volume			7,370		
Derivative,weighted average sold call | $ / CallPrice_mmbtu				6.25	
Derivative, sold put volume			7,370		
Derivative,weighted average sold put | $ / CallPrice_mmbtu				3.81	
Derivative, swap volume			0		

Derivative,weighted average swap | $ / CallPrice_mmbtu					0	
Collar One [Member] | European Gas NBP [Member]						
Derivative, contract period	Oct 2018 - Mar 2019	Oct 2018 - Mar 2019				
Description of presentation currency	EUR	EUR				
Derivative, bought put volume | mmbtu_d				3,685		
Derivative,weighted average bought put | $ / CallPrice_mmbtu					6.40	
Derivative, sold call volume			2,457			
Derivative,weighted average sold call | € / CallPrice_mmbtu						7.62
Derivative, sold put volume			0			
Derivative,weighted average sold put | $ / CallPrice_mmbtu					0	
Derivative, swap volume			0			
Derivative,weighted average swap | $ / CallPrice_mmbtu					0	
Collar One [Member] | European Gas NBP basis [Member]						
Derivative, contract period	Jan 2019 - Sep 2020	Jan 2019 - Sep 2020				
Description of presentation currency	USD	USD				
Derivative, bought put volume			7,500			
Derivative,weighted average bought put | $ / CallPrice_mmbtu					2.07	
Derivative, sold call volume			7,500			
Derivative, sold put volume			0			
Derivative,weighted average sold put | $ / CallPrice_mmbtu					0	
Derivative, swap volume			0			
Derivative,weighted average swap | $ / CallPrice_mmbtu					0	
Swap Contract Two [Member] | Crude oil dated brent [Member]						
Derivative, contract period	Apr 2018 - Mar 2019	Apr 2018 - Mar 2019				
Description of presentation currency	USD	USD				
Derivative, bought put volume			0			
Derivative,weighted average bought put | $ / CallPrice_mmbtu					0	

Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			750	
Derivative,weighted average swap | $ / CallPrice_mmbtu				61.33
Swap Contract Two [Member] | Crude oil west texas intermediate [Member]				
Derivative, contract period	Apr 2018 - Mar 2019	Apr 2018 - Mar 2019		
Description of presentation currency	USD	USD		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			250	
Derivative,weighted average swap | $ / CallPrice_mmbtu				54.00
Swap Contract Two [Member] | European Gas TTF [Member]				
Derivative, contract period	Jan 2018 - Dec 2019	Jan 2018 - Dec 2019		
Description of presentation currency	EUR	EUR		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			1,228	
Derivative,weighted average swap | $ / CallPrice_mmbtu				5.00
Swap Contract Two [Member] | North American Gas Socal Border [Member]				

Derivative, contract period	[1]	Feb 2019	Feb 2019		
Description of presentation currency	[1]	USD	USD		
Derivative, bought put volume	[1]			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu	[1]				0
Derivative, sold call volume	[1]			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu	[1]				0
Derivative, sold put volume	[1]			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu	[1]				0
Derivative, swap volume	[1]			10,000	
Derivative,weighted average swap | $ / CallPrice_mmbtu	[1]				4.39
Swap Contract Three [Member] | Crude oil dated brent [Member]					
Derivative, contract period		Jul 2018 - Jun 2019	Jul 2018 - Jun 2019		
Description of presentation currency		USD	USD		
Derivative, bought put volume				0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu					0
Derivative, sold call volume				0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu					0
Derivative, sold put volume				0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu					0
Derivative, swap volume				1,500	
Derivative,weighted average swap | $ / CallPrice_mmbtu					68.52
Swap Contract Three [Member] | European Gas TTF [Member]					
Derivative, contract period		Jul 2018 - Dec 2019	Jul 2018 - Dec 2019		
Description of presentation currency		EUR	EUR		
Derivative, bought put volume				0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu					0
Derivative, sold call volume				0	

Derivative,weighted average sold call | $ / CallPrice_mmbtu						0	
Derivative, sold put volume				0			
Derivative,weighted average sold put | $ / CallPrice_mmbtu						0	
Derivative, swap volume				4,913			
Derivative,weighted average swap | $ / CallPrice_mmbtu						4.98	
Swap Contract Three [Member] | North American Gas Socal Border [Member]							
Derivative, contract period	[1]	Mar 2019	Mar 2019				
Description of presentation currency	[1]	USD	USD				
Derivative, bought put volume	[1]			0			
Derivative,weighted average bought put | $ / CallPrice_mmbtu	[1]					0	
Derivative, sold call volume	[1]			0			
Derivative,weighted average sold call | $ / CallPrice_mmbtu	[1]					0	
Derivative, sold put volume	[1]			0			
Derivative,weighted average sold put | $ / CallPrice_mmbtu	[1]					0	
Derivative, swap volume	[1]			10,000			
Derivative,weighted average swap | $ / CallPrice_mmbtu	[1]					3.36	
Swaption Contract One [Member] | European Gas NBP [Member]							
Derivative, contract period		Jul 2019 - Jun 2021	Jul 2019 - Jun 2021				
Derivative, exercise date	[2]	Jun. 28, 2019	Jun. 28, 2019				
Description of presentation currency		EUR	EUR				
Derivative, bought put volume | mmbtu_d					0		
Derivative,weighted average bought put | $ / CallPrice_mmbtu						0	
Derivative, sold call volume				0			
Derivative,weighted average sold call | € / CallPrice_mmbtu							0
Derivative, sold put volume				0			
Derivative,weighted average sold put | $ / CallPrice_mmbtu						0	
Derivative, swap volume				9,827			
Derivative,weighted average swap | $ / CallPrice_mmbtu						5.64	

Swaption Contract One [Member] | European Gas TTF [Member]				
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Swaption Contract Two [Member] | European Gas NBP [Member]				
Derivative, contract period	Oct 2019 - Mar 2020	Oct 2019 - Mar 2020		
Derivative, exercise date	[2] Jun. 28, 2019	Jun. 28, 2019		
Description of presentation currency	EUR	EUR		
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			7,370	
Derivative,weighted average swap | $ / CallPrice_mmbtu				5.86
Swaption Contract Two [Member] | European Gas TTF [Member]				
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Swap Contract Four [Member] | Crude oil dated brent [Member]				
Derivative, contract period	Jan 2019 - Dec 2019	Jan 2019 - Dec 2019		
Description of presentation currency	USD	USD		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			2,250	
Derivative,weighted average swap | $ / CallPrice_mmbtu				73.17
Swap Contract Four [Member] | European Gas TTF [Member]				

Derivative, contract period	Jan 2019 - Dec 2019	Jan 2019 - Dec 2019		
Description of presentation currency	EUR	EUR		
Derivative, bought put volume			0	
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative,weighted average sold call | $ / CallPrice_mmbtu				0
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			2,457	
Derivative,weighted average swap | $ / CallPrice_mmbtu				4.92
Swaption Contract Three [Member] | European Gas NBP [Member]				
Derivative, contract period	Oct 2020 - Mar 2021	Oct 2020 - Mar 2021		
Derivative, exercise date	[2] Jun. 28, 2019	Jun. 28, 2019		
Description of presentation currency	EUR	EUR		
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			7,370	
Derivative,weighted average swap | $ / CallPrice_mmbtu				5.86
Swaption Contract Four [Member] | European Gas NBP [Member]				
Derivative, contract period	Oct 2021 - Mar 2022	Oct 2021 - Mar 2022		
Derivative, exercise date	[2] Jun. 28, 2019	Jun. 28, 2019		
Description of presentation currency	EUR	EUR		
Derivative,weighted average bought put | $ / CallPrice_mmbtu				0
Derivative, sold call volume			0	
Derivative, sold put volume			0	
Derivative,weighted average sold put | $ / CallPrice_mmbtu				0
Derivative, swap volume			7,370	

Derivative,weighted average swap | $ / CallPrice_mmbtu	5.86

[1] These swaps hedge a physical sales agreement to sell Alberta natural gas production at SOCAL Border pricing less a fixed differential.

[2] The sold swaption instrument allows the counterparty, at the specified date, to enter into a swap with Vermilion at the above detailed terms.