VERMILION ENERGY

NEWS RELEASE MARCH 1, 2018
VERMILION ENERGY INC. ANNOUNCES 2017 YEAR-END SUMMARY RESERVES AND RESOURCE INFORMATION

Vermilion Energy Inc. ("Vermilion", the "Company", "We" or "Our") (TSX, NYSE: VET) is pleased to announce summary 2017 year-end reserves and resource information. The estimates of reserves and resources and other oil and gas information contained in this news release have been estimated by GLJ Petroleum Consultants Ltd. ("GLJ") effective as at December 31, 2017 and prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGEH"). For additional information about Vermilion, including Vermilion's statement of reserves data and other information in Form 51-101F1, report on reserves data by independent qualified reserves evaluator or auditor in Form 51-101F2 and report of management and directors on oil and gas disclosure in Form 51-101F3, please review the Company's Annual Information Form for the year ended December 31, 2017, to be filed on March 1, 2018 and available on SEDAR at www.sedar.com and on the SEC's EDGAR system at www.sec.gov/edgar.shtml.

HIGHLIGHTS

- Total proved ("1P") reserves increased by 0.5% to 176.6 mmboe, while total proved plus probable ("2P") reserves increased 3% to 298.5 mmboe. We replaced 103% and 134% of production at the 1P and 2P levels respectively in 2017.

- Finding and Development ("F&D")(2) and Finding, Development and Acquisition ("FD&A")(2) costs, including Future Development Capital ("FDC") for 2017 on a 2P basis increased to $10.57/boe and $11.24/boe, compared to $5.57/boe and $6.62/boe in 2016, respectively. Our three-year F&D and FD&A costs, including FDC, on a 2P basis were $8.23/boe and $8.87/boe, respectively. The largest driver of the increase in F&D cost was the strengthening of the Euro relative to the Canadian dollar in GLJ's foreign exchange rate forecast as compared to the previous year, which increased FDC for our European properties. Operating Recycle Ratio(3) (including FDC) was 2.8x in 2017.

- Proved Developed Producing ("PDP") reserves increased by 1.3% to 123.8 mmboe at an average F&D cost (including FDC) of $12.41/boe resulting in a PDP Operating Recycle Ratio(3) (including FDC) of 2.4x. PDP reserves represent 70% of 1P reserves.

- At year-end 2017, 2P reserves were comprised of 29% Brent-based light crude, 15% North American-based light crude, 12% natural gas liquids, 19% European natural gas and 25% North American natural gas.

- We continued to build our strong resource base in our West Pembina area in Alberta. We added 29 (23.9 net) 2P locations in the condensate-rich portion of the Mannville gas play in West Pembina at an average reserves addition per well of approximately 520 mboe. The West Pembina-Mannville reserves are Vermilion's largest resource base, representing over 40% of total Canadian 2P reserves at December 31, 2017.

- In the Ferrier area of Alberta we added nine (7.1 net) 2P locations in the liquids-rich Mannville gas play at an average reserve addition per well of approximately 1,100 mboe.

- Our independent GLJ 2017 Resource Assessment(4) indicates risked low, best, and high estimates for contingent resources in the Development Pending category of 107.3(4) mmboe, 176.7(4) mmboe, and 253.6(4) mmboe, respectively. The GLJ 2017 Resource Assessment also indicates risked low, best, and high estimates for contingent resources in the Development Unclarified category of 7.5(4) mmboe, 32.8(4) mmboe, and 46.1(4) mmboe, respectively. Over 80% of our risked contingent resources reside in the Development Pending category. Prospective resources were assessed at risked low, best and high estimates of 51.5(4) mmboe, 153.4(4) mmboe, and 260.4(4) mmboe. Our contingent and prospective resource bases remain a source of reserve additions, with 20.5 mmboe of contingent resources and 1.7 mmboe of prospective resources converted to 2P reserves during 2017.

(1) As evaluated by GLJ Petroleum Consultants Ltd. ("GLJ") in a report dated February 1, 2018 with an effective date of December 31, 2017.

(2) F&D (finding and development) and FD&A (finding, development and acquisition) costs are used as a measure of capital efficiency and are calculated by dividing the applicable capital expenditures for the period, including the change in undiscounted future development capital ("FDC"), by the change in the reserves, incorporating revisions and production, for the same period.

(3) "Operating Recycle Ratio" is a measure of capital efficiency calculated by dividing the Operating Netback by the cost of adding reserves (F&D cost). "Operating Netback" is calculated as sales less royalties, operating expense, transportation costs, PRRT and realized hedging gains and losses presented on a per unit basis.

(4) Vermilion retained GLJ to conduct an independent resource evaluation dated February 1, 2018 to assess contingent and prospective resources across all of the Company's key operating regions with an effective date of December 31, 2017 (the "GLJ 2017 Resource Assessment"). The aggregate associated chance of development for each of the low, best and high estimate for contingent resources in the Development Pending category are 84%, 83% and 82%, respectively. The aggregate associated chance of development for each of the low, best and high estimate for contingent resources in the Development Unclarified category are 56%, 46% and 47%, respectively. The aggregate associated chance of commerciality for each of the low, best and high estimate for prospective resources in the Prospect category are 23%, 22% and 22%, respectively. There is uncertainty that it will be commercially viable to produce any portion of the resources. For further information, see the "Contingent Resources" section of this news release.

DISCLAIMER

Certain statements included or incorporated by reference in this news release 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 news release may include, but are not limited to:

- capital expenditures;
- business strategies and objectives;
- estimated reserve quantities and the discounted present value of future net cash flows from such reserves;
- petroleum and natural gas sales;
- future production levels (including the timing thereof) and rates of average annual production growth, estimated contingent resources 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 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 the annual information form of the Company for the year ended December 31, 2017 or in the Company's other filings with Canadian securities authorities.

The forward-looking statements or information contained in this news release 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.

RESERVES, FUTURE NET REVENUE AND OTHER OIL AND GAS INFORMATION

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, independent petroleum engineering consultants in Calgary in a report dated February 1, 2018 with an effective date of December 31, 2017 (the "GLJ 2017 Reserves Evaluation"). The GLJ 2017 Reserves Evaluation was prepared in accordance with National Instrument 51-101 and COGEH.

Reserves and other oil and gas information in this news release is effective December 31, 2017 unless otherwise stated.

All evaluations of future net production 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 production revenues estimated by the GLJ 2017 Reserves Evaluation 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 2017 Reserve Evaluation. There is no assurance that the future price and cost assumptions used in the GLJ 2017 Reserves Evaluation will prove accurate and variances could be material.**

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

Estimates of reserves have been made assuming that development of each property, in respect of which estimates have been made, will occur without regard to the availability of funding required for that development.

With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Pricing used in the forecast price estimates is set forth in the table below and referenced in the notes to subsequent tables.

Table 1: Forecast Prices used in Estimates (1)

		Light Crude Oil and & Medium Crude Oil		Crude Oil	Conventional Natural Gas Canada	Conventional Natural Gas Europe	Natural Gas Liquids	Inflation Rate	Exchange Rate	Exchange Rate
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40˚ API ($Cdn/bbl)**	**Cromer Medium 29.3˚ API ($Cdn/bbl)**	**Brent Blend FOB North Sea ($US/bbl)**	**AECO Gas Price ($Cdn/MMBtu)**	**National Balancing Point (UK) ($US/MMBtu)**	**FOB Field Gate ($Cdn/bbl)**	**Percent Per Year**	**($US/$Cdn)**	**($Cdn/EUR)**
2017	50.88	62.78	59.90	54.16	2.16	5.63	46.67	1.60	0.77	1.46
Forecast										
2018	59.00	70.25	65.34	65.50	2.20	6.25	56.85	2.00	0.79	1.49
2019	59.00	70.25	65.34	63.50	2.54	6.50	53.46	2.00	0.79	1.46
2020	60.00	70.31	65.39	63.00	2.88	6.75	53.18	2.00	0.80	1.44
2021	66.00	72.84	67.74	66.00	3.24	7.00	54.74	2.00	0.81	1.42
2022	69.00	75.61	70.32	69.00	3.47	7.15	56.37	2.00	0.82	1.40
2023	72.00	78.31	72.83	72.00	3.58	7.30	58.31	2.00	0.83	1.39
2024	75.00	81.93	76.19	75.00	3.66	7.45	60.94	2.00	0.83	1.39
2025	78.00	85.54	79.55	78.00	3.73	7.60	63.57	2.00	0.83	1.39
2026	80.33	88.35	82.16	80.33	3.80	7.75	65.61	2.00	0.83	1.39
2027	81.88	90.22	83.90	81.88	3.88	7.90	66.96	2.00	0.83	1.39
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	0.83	1.39

Note:

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

All forecast prices in the tables above are provided by GLJ. For 2017, the price of crude oil in the United States is based on WTI. The benchmark price for Canadian crude oil is Edmonton Par and Canadian natural gas is priced against AECO. The benchmark price for Australia, France and Germany crude oil is Dated Brent. The price of our natural gas in Ireland is based on the NBP index. The price of Vermilion's natural gas in the Netherlands and Germany is based on the TTF day/month-ahead index, as determined on the Title Transfer Facility Virtual Trading Point. For the year ended December 31, 2017, the average realized sales prices before hedging were $57.64 per bbl (United States) for WTI, $51.36 per bbl for Canadian-based crude oil, condensate and NGLs and $2.34 per Mcf for Canadian natural gas, $73.99 per bbl (Australia), $67.08 per bbl (France) for Brent-based crude oil, $7.19 per Mcf (Ireland), $7.18 per Mcf (Netherlands), and $6.38 per Mcf (Germany).

The following table summarizes the capital expenditures made by Vermilion on oil and gas properties for the year ended December 31, 2017:

Table 2: Capital Costs Incurred

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

The following table sets forth the reserve life index based on total proved and proved plus probable reserve and fourth quarter 2017 production of 72,821 boe/d.

Table 3: Reserve Life Index

Commodity	Production	Reserve Life Index (years)	
	Fourth Quarter 2017	Total Proved	Proved Plus Probable
Crude oil, condensate and natural gas liquids (bbl/d)	33,109	8.5	13.8
Natural gas (mmcf/d)	238.27	5.1	9.1
Oil Equivalent (boe/d)	72,821	6.6	11.2

The following tables provide reserves data and a breakdown of future net revenue by component and production group using forecast prices and costs. For Canada, the tables following include Alberta gas cost allowance.

The following tables may not total due to rounding.

Table 4: Oil and Gas Reserves - Based on Forecast Prices and Costs (1)

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (MMcf)	Net (2) (MMcf)
Proved Developed Producing (3) (5) (6)								
Australia	9,065	9,065	—	—	—	—	—	—
Canada	11,148	10,219	—	—	—	—	139,772	128,023
France	35,944	33,265	—	—	—	—	8,619	7,939
Germany	5,008	4,880	—	—	—	—	29,791	26,881
Ireland	—	—	—	—	—	—	81,803	81,803
Netherlands	—	—	—	—	—	—	37,296	24,721
United States	982	782	—	—	—	—	1,071	854
Total Proved Developed Producing	62,147	58,211	—	—	—	—	298,352	270,221

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

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Developed Non-Producing [3] [5] [7]								
Australia	350	350	—	—	—	—		
Canada	878	768	—	—	—	—	9,420	8,489
France	562	492	—	—	—	—	—	—
Germany	539	521	—	—	—	—	8,959	8,156
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	21,010	20,482
United States	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	2,329	2,131	—	—	—	—	39,389	37,127

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

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved Undeveloped [3] [8]								
Australia	1,500	1,500	—	—	—	—	—	—
Canada	7,634	6,929	—	—	—	—	91,104	83,603
France	4,140	3,767	—	—	—	—	64	64
Germany	241	235	—	—	—	—	2,361	1,939
Ireland	—	—	—	—	—	—	—	—
Netherlands	—	—	—	—	—	—	2,620	2,620
United States	3,300	2,693	—	—	—	—	3,309	2,700
Total Proved Undeveloped	16,815	15,124	—	—	—	—	99,458	90,926

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

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Proved [3]								
Australia	10,915	10,915	—	—	—	—	—	—
Canada	19,660	17,916	—	—	—	—	240,296	220,115
France	40,646	37,524	—	—	—	—	8,683	8,003
Germany	5,788	5,636	—	—	—	—	41,111	36,976
Ireland	—	—	—	—	—	—	81,803	81,803
Netherlands	—	—	—	—	—	—	60,926	47,823
United States	4,282	3,475	—	—	—	—	4,380	3,554
Total Proved	81,291	75,466	—	—	—	—	437,199	398,274

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

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (Mbbl)	Net [2] (Mbbl)	Gross [2] (MMcf)	Net [2] (MMcf)
Probable [4]								
Australia	4,650	4,650	—	—	—	—	—	—
Canada	12,885	11,417	—	—	—	—	181,055	164,336
France	21,786	20,115	—	—	—	—	1,854	1,769
Germany	3,000	2,931	—	—	—	—	53,134	47,092
Ireland	—	—	—	—	—	—	51,389	51,389
Netherlands	—	—	—	—	—	—	44,380	35,383
United States	7,073	5,827	—	—	—	—	7,520	6,194
Total Probable	49,394	44,940	—	—	—	—	339,332	306,163

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

	Light Crude Oil & Medium Crude Oil		Heavy Oil		Tight Oil		Conventional Natural Gas	
	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (Mbbl)	Net (2) (Mbbl)	Gross (2) (MMcf)	Net (2) (MMcf)
Proved Plus Probable (3) (4)								
Australia	15,565	15,565	—	—	—	—	—	—
Canada	32,545	29,333	—	—	—	—	421,351	384,451
France	62,432	57,639	—	—	—	—	10,537	9,772
Germany	8,788	8,567	—	—	—	—	94,245	84,068
Ireland	—	—	—	—	—	—	133,192	133,192
Netherlands	—	—	—	—	—	—	105,306	83,206
United States	11,355	9,302	—	—	—	—	11,900	9,748
Total Proved Plus Probable	130,685	120,406	—	—	—	—	776,531	704,437

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

Notes:

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

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

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

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

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

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

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

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

Table 5: Net Present Values of Future Net Revenue - Based on Forecast Prices and Costs (1)

	Before Deducting Future Income Taxes Discounted At					After Deducting Future Income Taxes Discounted At				
(M$)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved Developed Producing (2) (4) (5)										
Australia	(17,017)	90,880	132,474	146,048	147,713	77,180	124,390	136,979	136,121	130,383
Canada	929,867	770,860	647,843	559,708	494,964	929,867	770,860	647,843	559,708	494,964
France	1,791,774	1,315,070	1,030,403	849,032	725,407	1,473,144	1,091,894	858,839	708,168	604,390
Germany	276,577	249,619	206,965	174,876	151,703	276,578	249,619	206,965	174,876	151,703
Ireland	389,204	376,115	346,327	316,408	290,143	389,204	376,115	346,327	316,408	290,143
Netherlands	48,794	60,781	66,245	68,260	68,404	48,793	60,781	66,245	68,260	68,404
United States	44,617	34,550	28,272	24,106	21,170	44,619	34,550	28,272	24,106	21,170
Total Proved Developed Producing	3,463,816	2,897,875	2,458,529	2,138,438	1,899,504	3,239,385	2,708,209	2,291,470	1,987,647	1,761,157
Proved Developed Non-Producing (2) (4) (6)										
Australia	28,079	24,122	20,869	18,180	15,942	28,079	24,122	20,869	18,180	15,942
Canada	60,804	42,405	32,416	26,238	22,048	60,804	42,405	32,417	26,238	22,048
France	10,082	8,113	6,095	4,559	3,438	6,848	5,499	3,953	2,763	1,896
Germany	49,825	37,600	27,510	20,411	15,501	32,059	29,369	23,502	18,374	14,426
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	70,140	70,244	67,599	63,916	59,989	53,099	54,167	52,375	49,452	46,205
United States	—	—	—	—	—	—	—	—	—	—
Total Proved Developed Non-Producing	218,930	182,484	154,489	133,304	116,918	180,889	155,562	133,116	115,007	100,517
Proved Undeveloped (2) (7)										
Australia	54,981	43,263	34,175	27,105	21,564	25,101	18,532	13,890	10,524	8,032
Canada	524,830	354,396	246,584	175,252	126,009	397,236	281,016	202,741	148,193	108,836
France	177,851	128,923	96,156	73,638	57,592	127,650	88,876	63,091	45,660	33,460
Germany	17,161	11,696	8,012	5,495	3,737	12,154	8,910	6,412	4,551	3,166
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	10,559	8,825	7,405	6,255	5,323	7,921	6,405	5,174	4,189	3,401
United States	110,911	64,500	39,231	24,394	15,111	105,425	62,306	38,295	23,973	14,912
Total Proved Undeveloped	896,293	611,603	431,563	312,139	229,336	675,487	466,045	329,603	237,090	171,807
Proved (2)										
Australia	66,043	158,265	187,518	191,333	185,219	130,360	167,044	171,738	164,825	154,357
Canada	1,515,501	1,167,661	926,843	761,198	643,021	1,387,907	1,094,281	883,001	734,139	625,848
France	1,979,707	1,452,106	1,132,654	927,229	786,437	1,607,642	1,186,269	925,883	756,591	639,746
Germany	343,563	298,915	242,487	200,782	170,941	320,791	287,898	236,879	197,801	169,295
Ireland	389,204	376,115	346,327	316,408	290,143	389,204	376,115	346,327	316,408	290,143
Netherlands	129,493	139,850	141,249	138,431	133,716	109,813	121,353	123,794	121,901	118,010
United States	155,528	99,050	67,503	48,500	36,281	150,044	96,856	66,567	48,079	36,082

Total Proved	4,579,039	3,691,962	3,044,581	2,583,881	2,245,758	4,095,761	3,329,816	2,754,189	2,339,744	2,033,481
Probable [3]										
Australia	154,459	149,732	125,619	102,719	84,652	93,591	88,478	72,912	58,670	47,633
Canada	1,363,584	814,347	539,091	384,014	288,722	1,003,602	592,655	390,429	278,355	210,521
France	1,200,008	673,205	431,159	299,927	219,972	879,913	477,377	292,831	193,985	134,663
Germany	414,585	244,149	151,416	100,767	70,641	293,314	172,157	104,603	68,306	47,063
Ireland	350,695	246,321	182,785	141,844	114,117	350,695	246,321	182,785	141,844	114,117
Netherlands	197,136	167,242	141,871	121,179	104,496	130,277	108,388	89,527	74,196	61,980
United States	353,649	198,078	124,603	84,897	61,103	278,493	157,846	100,547	69,404	50,591
Total Probable	4,034,116	2,493,074	1,696,544	1,235,347	943,703	3,029,885	1,843,222	1,233,634	884,760	666,568
Proved Plus Probable [2] [3]										
Australia	220,502	307,997	313,137	294,052	269,871	223,951	255,522	244,650	223,495	201,990
Canada	2,879,085	1,982,008	1,465,934	1,145,212	931,743	2,391,509	1,686,936	1,273,430	1,012,494	836,369
France	3,179,715	2,125,311	1,563,813	1,227,156	1,006,409	2,487,555	1,663,646	1,218,714	950,576	774,409
Germany	758,148	543,064	393,903	301,549	241,582	614,105	460,055	341,482	266,107	216,358
Ireland	739,899	622,436	529,112	458,252	404,260	739,899	622,436	529,112	458,252	404,260
Netherlands	326,629	307,092	283,120	259,610	238,212	240,090	229,741	213,321	196,097	179,990
United States	509,177	297,128	192,106	133,397	97,384	428,537	254,702	167,114	117,483	86,673
Total Proved Plus Probable	8,613,155	6,185,036	4,741,125	3,819,228	3,189,461	7,125,646	5,173,038	3,987,823	3,224,504	2,700,049

Notes:

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

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

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

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

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

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

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

Table 6: Total Future Net Revenue (Undiscounted) Based on Forecast Prices and Costs [(1)]

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

Notes:

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

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

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

Table 7: Future Net Revenue by Production Group Based on Forecast Prices and Costs (1)

	Future Net Revenue Before Income Taxes (2) (Discounted at 10% Per Year)	Unit Value
Proved Developed Producing	**(M$)**	**($/boe)**
Light Crude Oil & Medium Crude Oil (3)	1,764,235	27.51
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	693,722	14.33
Shale Gas	122	8.56
Coal Bed Methane	450	1.25
Total Proved Developed Producing	2,458,529	21.77
Proved Developed Non-Producing		
Light Crude Oil & Medium Crude Oil (3)	43,821	18.44
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	108,904	17.4
Shale Gas	984	4.54
Coal Bed Methane	780	2.13
Total Proved Developed Non-Producing	154,489	16.76
Proved Undeveloped		
Light Crude Oil & Medium Crude Oil (3)	273,008	14.16
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	158,318	8.31
Shale Gas	—	—
Coal Bed Methane	237	0.77
Total Proved Undeveloped	431,563	12.04
Proved		
Light Crude Oil & Medium Crude Oil (3)	2,081,064	24.35
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	960,944	12.92
Shale Gas	1,106	4.58
Coal Bed Methane	1,467	1.36
Total Proved	3,044,581	18.94
Probable		
Light Crude Oil & Medium Crude Oil (3)	1,031,625	19.21
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	663,113	11.98
Shale Gas	238	5.49
Coal Bed Methane	1,568	3.31
Total Probable	1,696,544	15.48
Proved Plus Probable		
Light Crude Oil & Medium Crude Oil (3)	3,112,689	22.47
Heavy Oil (3)	—	—
Conventional Natural Gas (4)	1,624,057	12.42
Shale Gas	1,344	4.85
Coal Bed Methane	3,035	1.92
Total Proved Plus Probable	4,741,125	17.53

Notes:

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

(2) Other Company revenue and costs not related to a specific product type have been allocated proportionately to the specified product types. Unit values are based on Company net reserves. Net present value of reserves categories are an approximation based on major products.
(3) Including solution gas and other by-products.
(4) Including by-products but excluding solution gas.

Reconciliations of Changes in Reserves

The following tables set forth a reconciliation of the changes in Vermilion's gross light and medium crude oil, heavy oil and associated and non-associated gas (combined) reserves as at December 31, 2017 compared to such reserves as at December 31, 2016.

Table 8: Reconciliation of Company Gross Reserves by Principal Product Type - Based on Forecast Prices and Costs (3)

AUSTRALIA	Total Oil (4)			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P (1) (2)	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	12,418	4,650	17,068	12,418	4,650	17,068	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	603	—	603	603	—	603	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	(2,106)	—	(2,106)	(2,106)	—	(2,106)	—	—	—	—	—	—
At December 31, 2017	10,915	4,650	15,565	10,915	4,650	15,565	—	—	—	—	—	—

	Total Gas (4)			Conventional Natural Gas			Coal Bed Methane (5)			Shale Gas (5)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

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

CANADA	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	21,974	14,105	36,079	21,962	14,103	36,065	—	—	—	12	2	14
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	594	302	896	594	302	896	—	—	—	—	—	—
Technical Revisions	(681)	(1,542)	(2,223)	(670)	(1,540)	(2,210)	—	—	—	(11)	(2)	(13)
Acquisitions	16	4	20	16	4	20	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(48)	16	(32)	(48)	16	(32)	—	—	—	—	—	—
Production	(2,195)	—	(2,195)	(2,194)	—	(2,194)	—	—	—	(1)	—	(1)
At December 31, 2017	19,660	12,885	32,545	19,660	12,885	32,545	—	—	—	—	—	—

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

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

FRANCE	Total Oil (4)			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P (1) (2)	**Proved**	**Probable**	**Proved + Probable**	**Proved**	**Probable**	**Proved + Probable**	**Proved**	**Probable**	**Proved + Probable**	**Proved**	**Probable**	**Proved + Probable**
Factors	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**	**(Mbbl)**
At December 31, 2016	42,044	21,933	63,977	42,044	21,933	63,977	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,688	1,879	3,567	1,688	1,879	3,567	—	—	—	—	—	—
Technical Revisions	1,086	(1,912)	(826)	1,086	(1,912)	(826)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(126)	(114)	(240)	(126)	(114)	(240)	—	—	—	—	—	—
Production	(4,046)	—	(4,046)	(4,046)	—	(4,046)	—	—	—	—	—	—
At December 31, 2017	40,646	21,786	62,432	40,646	21,786	62,432	—	—	—	—	—	—

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

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

GERMANY	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	5,288	2,279	7,567	5,288	2,279	7,567	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	300	275	575	300	275	575	—	—	—	—	—	—
Technical Revisions	699	480	1,179	699	480	1,179	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(112)	(34)	(146)	(112)	(34)	(146)	—	—	—	—	—	—
Production	(387)	—	(387)	(387)	—	(387)	—	—	—	—	—	—
At December 31, 2017	5,788	3,000	8,788	5,788	3,000	8,788	—	—	—	—	—	—

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

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

IRELAND	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

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

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

NETHERLANDS	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1] [2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	—	—	—	—	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—	—	—	—	—
At December 31, 2017	—	—	—	—	—	—	—	—	—	—	—	—

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

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

UNITED STATES	Total Oil (4)			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P (1) (2)	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	3,169	5,727	8,896	3,169	5,727	8,896	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	1,413	1,483	2,896	1,413	1,483	2,896	—	—	—	—	—	—
Technical Revisions	(49)	(133)	(182)	(49)	(133)	(182)	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(9)	(4)	(13)	(9)	(4)	(13)	—	—	—	—	—	—
Production	(242)	—	(242)	(242)	—	(242)	—	—	—	—	—	—
At December 31, 2017	4,282	7,073	11,355	4,282	7,073	11,355	—	—	—	—	—	—

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

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

TOTAL COMPANY	Total Oil [4]			Light Crude Oil & Medium Crude Oil			Heavy Oil			Tight Oil		
Proved Probable P+P [1,2]	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
At December 31, 2016	84,893	48,694	133,587	84,881	48,692	133,573	—	—	—	12	2	14
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	3,995	3,939	7,934	3,995	3,939	7,934	—	—	—	—	—	—
Technical Revisions	1,658	(3,107)	(1,449)	1,669	(3,105)	(1,436)	—	—	—	(11)	(2)	(13)
Acquisitions	16	4	20	16	4	20	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors	(295)	(136)	(431)	(295)	(136)	(431)	—	—	—	—	—	—
Production	(8,976)	—	(8,976)	(8,975)	—	(8,975)	—	—	—	(1)	—	(1)
At December 31, 2017	81,291	49,394	130,685	81,291	49,394	130,685	—	—	—	—	—	—

	Total Gas [4]			Conventional Natural Gas			Coal Bed Methane [5]			Shale Gas [5]		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
At December 31, 2016	438,387	311,296	749,683	428,955	306,335	735,290	8,061	4,677	12,738	1,371	284	1,655
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	67,648	38,989	106,637	66,683	38,446	105,129	965	543	1,508	—	—	—
Technical Revisions	20,541	(5,175)	15,366	19,902	(5,169)	14,733	799	64	863	(160)	(70)	(230)
Acquisitions	3,452	1,113	4,565	2,686	872	3,558	766	241	1,007	—	—	—
Dispositions	(2,182)	(2,150)	(4,332)	(576)	(231)	(807)	(1,606)	(1,919)	(3,525)	—	—	—
Economic Factors	(3,722)	(1,474)	(5,196)	(2,561)	(921)	(3,482)	(1,161)	(553)	(1,714)	—	—	—
Production	(79,073)	—	(79,073)	(77,890)	—	(77,890)	(1,111)	—	(1,111)	(72)	—	(72)
At December 31, 2017	445,051	342,599	787,650	437,199	339,332	776,531	6,713	3,053	9,766	1,139	214	1,353

	Natural Gas Liquids			BOE		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
Factors	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
At December 31, 2016	17,856	13,730	31,586	175,815	114,307	290,122
Discoveries	—	—	—	—	—	—
Extensions & Improved Recovery	5,881	1,469	7,350	21,151	11,906	33,057
Technical Revisions	(128)	189	61.49	4,953	(3,781)	1,172
Acquisitions	351	113	464	942	303	1,245
Dispositions	(3)	(1)	(4)	(367)	(359)	(726)
Economic Factors	(185)	(68)	(253)	(1,101)	(450)	(1,551)
Production	(2,674)	—	(2,674)	(24,829)	—	(24,829)
At December 31, 2017	21,098	15,432	36,530.49	176,564	121,926	298,490

Notes:

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

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

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

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

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

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).

Table 9: Future Development Costs(1)

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

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

Note:

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

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

APPENDIX A
CONTINGENT RESOURCES

Summary information regarding contingent resources and net present value of future net revenues from contingent resources are set forth below and are derived, in each case, from the GLJ Resources Assessment. The GLJ Resources Assessment was prepared in accordance with COGEH and NI-51-101 by GLJ, an independent qualified reserve evaluator. All contingent resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2017. Contingent resources are in addition to reserves estimated in the GLJ Report.

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

The GLJ Resources Assessment estimated gross risked contingent resources with a project maturity subclass of “Development Pending” of 107.3 million boe (low estimate) to 253.6 million boe (high estimate), with a best estimate of 176.7 million boe. Contingent resources are in addition to reserves estimated in the GLJ Report.

The GLJ Resources Assessment estimated gross risked contingent resources with a project maturity subclass of “Development Unclarified” of 7.5 million boe (low estimate) to 46.1 million boe (high estimate), with a best estimate of 32.8 million boe.

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

Table 10: Summary of Risked Oil and Gas Contingent Resources as at December 31, 2017 (1) (2) - Forecast Prices and Costs (3) (4)

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

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

Table 11: Summary of Risked Net Present Value of Future Net Revenues as at December 31, 2017 - Forecast Prices and Costs (3)

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

Notes:

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

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

(3) The forecast price and cost assumptions utilized in the year-end 2017 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See "Forecast Prices Used in Estimates" in this AIF.

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

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

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

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

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

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

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

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

(11) Risked development pending best estimate contingent resources for Australia have been estimated based on the continued drilling in our active core asset (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $143 MM and the expected timeline is between 6 and 8 years. The specific contingencies for these resources are corporate commitment and development timing.

(12) Risked development pending best estimate contingent resources for Canada have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $1,066 MM and the expected timeline is between 3 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(13) Risked development pending best estimate contingent resources for France have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $571 MM and the expected timeline is between 3 and 12 years. The specific contingencies for these resources are corporate commitment and development timing.

(14) Risked development pending best estimate contingent resources for Germany have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial

production is $75 MM and the expected timeline is between 2 and 4 years. The specific contingencies for these resources are corporate commitment and development timing.

(15) Risked development pending best estimate contingent resources for Netherlands have been estimated based on the continued drilling in our active core assets (see "Description of Properties" section of this AIF) using established recovery technologies. The risked estimated cost to bring these contingent resources on commercial production is $45 MM and the expected timeline is between 2 and 4 years. The specific contingencies for these resources are corporate commitment and development timing.

(16) Risked development pending best estimate contingent resources for USA have been estimated based on the continued drilling in our active core asset (see "Description of Properties" section of this AIF) using established recovery technologies. The risked risked estimated cost to bring these contingent resources on commercial production is $380 MM and the expected timeline is between 1 and 11 years. The specific contingencies for these resources are corporate commitment and development timing.

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

(18) In Canada, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 26.8 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $323 MM with an expected timeline of 3 to 12 years.

Edson Duvernay	Based on contingencies related to corporate commitment and development timing, economic risks associated with lower liquid yields, and capital and operating cost uncertainty, GLJ has estimated risked unclarified best estimate contingent resources at 15.5 mmboe and the risked estimated cost to bring these resources on commercial production is $242.8 MM. The expected timeline is 3 to 7 years.
Ferrier Notikewin	Based on contingencies related to corporate commitment and development timing that is greater than 10 years, GLJ has estimated risked unclarified best estimate contingent resources at 4.7 mmboe and the risked estimated cost to bring these resources on commercial production is $31 MM. The expected timeline is 11 to 15 years.
Ferrier Falher	Based on contingencies related to corporate commitment and development timing that is greater than 10 years, GLJ has estimated risked unclarified best estimate contingent resources at 3.2 mmboe and the risked estimated cost to bring these resources on commercial production is $23 MM. The expected timeline is 11 to 15 years.
West Pembina Glauconite	Based on contingencies related to corporate commitment and development timing as well as economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands, GLJ has estimated risked unclarified best estimate contingent resources at 3.3 mmboe and the risked estimated cost to bring these resources on commercial production is $26 MM. The expected timeline is 4 to 6 years.

(19) In France, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 2.5 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $37 MM with an expected timeline of 7 to 8 years.

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

(20) In the Netherlands, GLJ has estimated an aggregate of risked unclarified best estimate contingent resources of 3.1 mmboe for the projects outlined below. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $51 MM with an expected timeline of 8 to 10 years.

Netherlands East	Based on contingencies related to corporate commitment and development timing along with proof-of-concept utilizing directional drilling and unknown deliverability from Zechstein carbonates, GLJ has estimated risked unclarified best estimate contingent resources at 1.5 mmboe and the risked estimated cost to bring these resources on commercial production is $25 MM. The expected timeline is 3 to 7 years.
Netherlands West	Based on contingencies related to corporate commitment and development timing along with further study required regarding the deliverability of the Bunter sands, GLJ has estimated risked unclarified best estimate contingent resources at 1.6 mmboe and the risked estimated cost to bring these resources on commercial production is $26 MM. The expected timeline is 3 to 5 years.

PROSPECTIVE RESOURCES

Summary information regarding prospective resources and net present value of future net revenues from prospective resources are set forth below and are derived, in each case, from the GLJ Resources Assessment. The GLJ Resources Assessment was prepared in accordance with COGEH and NI-51-101 by GLJ, an independent qualified reserve evaluator. All prospective resources evaluated in the GLJ Resources Assessment were deemed economic at the effective date of December 31, 2017. Prospective resources are in addition to reserves estimated in the GLJ Report.

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

The GLJ Resources Assessment estimated gross risked prospective resources of 51.5 million boe (low estimate) to 260.4 million boe (high estimate), with a best estimate of 153.4 million boe.

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

Summary of Risked Oil and Gas Prospective Resources as at **December 31, 2017**(1) (2) ***- Forecast Prices and Costs*** (3) (4)

Resources	Light Crude Oil & Medium Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		BOE		Unrisked BOE		
Project													
Maturity	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Chance of Commerciality	Gross	Net
Sub-Class	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	% (9)	(Mboe)	(Mboe)
Prospective - Low Estimate													
Prospect (10)													
Australia	—	—	—	—	—	—	—	—	—	—		—	—
Canada	185	168	66,480	61,570	—	—	4,522	3,982	15,787	14,412	34.0 %	46,435	42,388
France	5,528	4,977	—	—	—	—	—	—	5,528	4,977	21.3 %	25,904	23,366
Germany	—	—	136,066	116,769	—	—	—	—	22,678	19,462	29.0 %	78,200	67,110
Ireland	—	—	—	—	—	—	—	—	—	—		—	—
Netherlands	—	—	44,603	41,372	—	—	50	46	7,484	6,941	10.1 %	73,823	68,723
USA	—	—	—	—	—	—	—	—	—	—		—	—
Total	5,713	5,145	247,149	219,711	—	—	4,572	4,028	51,477	45,792	22.9 %	224,362	201,587
Prospective - Best Estimate													
Prospect (10)													
Australia (11)	579	579	—	—	—	—	—	—	579	579	48.0 %	1,206	1,206
Canada (12)	2,090	1,871	162,093	147,542	112,623	106,205	24,876	22,098	72,752	66,260	23.5 %	309,610	281,957
France (13)	16,335	14,636	—	—	—	—	—	—	16,335	14,636	21.4 %	76,358	68,393
Germany (14)	—	—	292,725	251,987	—	—	—	—	48,788	41,998	29.0 %	168,235	144,821
Ireland	—	—	—	—	—	—	—	—	—	—		—	—
Netherlands (15)	—	—	89,366	82,029	—	—	96	89	14,990	13,761	10.2 %	147,256	134,912
USA	—	—	—	—	—	—	—	—	—	—		—	—
Total	19,004	17,086	544,184	481,558	112,623	106,205	24,972	22,187	153,444	137,234	21.8 %	702,665	631,289
Prospective - High Estimate													
Prospect (10)													
Australia	1,462	1,462	—	—	—	—	—	—	1,462	1,462	48.0 %	3,046	3,046
Canada	2,684	2,383	231,682	209,203	147,282	136,241	38,134	32,553	103,979	92,510	23.8 %	436,843	388,697
France	35,640	32,301	—	—	—	—	—	—	35,640	32,301	22.8 %	156,320	141,671
Germany	—	—	554,429	479,424	—	—	—	—	92,405	79,904	29.0 %	318,638	275,531
Ireland	—	—	—	—	—	—	—	—	—	—		—	—
Netherlands	—	—	160,271	148,815	—	—	171	159	26,883	24,962	10.6 %	252,881	235,491
USA	—	—	—	—	—	—	—	—	—	—		—	—
Total	39,786	36,146	946,382	837,442	147,282	136,241	38,305	32,712	260,369	231,139	22.3 %	1,167,728	1,044,436

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

Resources Project Maturity Sub-Class (M$)	Before Income Taxes, Discounted at [5]					After Income Taxes, Discounted at [5]				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Prospective (Pr1) -Low Estimate [6]										
Prospect [10]										
Australia	—	—	—	—	—	—	—	—	—	—
Canada	207,770	95,938	44,659	19,798	7,252	169,908	75,170	32,207	11,777	1,780
France	238,004	131,320	76,140	46,216	29,224	187,762	102,964	59,117	35,418	22,032
Germany	368,323	169,166	74,634	29,008	6,565	252,131	112,397	44,221	11,701	(3,782)
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	274,447	125,347	68,782	42,725	28,862	145,575	61,601	29,728	15,701	8,716
USA	—	—	—	—	—	—	—	—	—	—
Total	1,088,544	521,771	264,215	137,747	71,903	755,376	352,132	165,273	74,597	28,746
Prospective (Pr2) -Best Estimate [7]										
Prospect [10]										
Australia [11]	41,338	23,669	14,015	8,555	5,365	16,344	8,905	4,999	2,884	1,705
Canada [12]	1,491,712	623,324	281,364	133,988	65,665	1,065,129	430,068	182,436	78,310	31,913
France [13]	722,008	401,287	237,931	149,181	98,046	533,938	289,739	167,209	101,849	64,935
Germany [14]	1,259,830	556,044	260,954	126,408	60,705	883,031	385,237	174,225	78,544	32,534
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands [15]	664,124	319,700	187,996	124,429	88,794	358,130	165,622	92,188	57,620	38,865
USA	—	—	—	—	—	—	—	—	—	—
Total	4,179,012	1,924,024	982,260	542,561	318,575	2,856,572	1,279,571	621,057	319,207	169,952
Prospect [10]										
Australia	136,670	74,308	43,028	26,126	16,460	57,049	30,416	17,274	10,298	6,378
Canada	2,681,315	1,109,012	521,064	267,963	146,940	1,909,850	772,257	349,756	171,101	87,888
France	1,937,405	1,011,329	573,475	347,956	223,097	1,458,826	749,093	417,797	249,512	157,614
Germany	2,751,890	1,219,651	585,356	295,653	153,056	1,969,884	858,139	400,902	194,089	93,693
Ireland	—	—	—	—	—	—	—	—	—	—
Netherlands	1,355,100	675,317	411,776	281,254	206,125	738,129	360,566	214,793	143,533	103,140
USA	—	—	—	—	—	—	—	—	—	—
Total	8,862,380	4,089,617	2,134,699	1,218,952	745,678	6,133,738	2,770,471	1,400,522	768,533	448,713

Notes:

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

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

(3) The forecast price and cost assumptions utilized in the year-end 2017 reserves report were also utilized by GLJ in preparing the GLJ Resource Assessment. See "GLJ December 31, 2017 Forecast Prices" in this AIF.

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

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

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

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

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

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

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

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

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

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

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

(11) Prospective resources for Australia have been estimated based on development timing and reservoir risk, GLJ has estimated the CoDev at 80% and the CoDis at 60%. The corresponding chance of commerciality is 48%. Risked best estimate prospective resources have been estimated at .06 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is $17 MM. The expected development timeline is 8 years.

(12) Prospective resources for Canada have been estimated based on the individual prospects outlined below. GLJ has estimated the aggregate CoDev at 27% and the aggregate CoDis at 88%. The corresponding chance of commerciality is 23%. Risked best estimate prospective resources have been estimated at an aggregate of

72.8 mmboe. Utilizing established recovery technology, the risked estimated cost to bring these resources on commercial production is an aggregate of $1061 MM. The expected development timeline is 2 to 20 years.

Edson Duvernay	Based on reservoir risk, development timing and economic risk related to capital and operating cost uncertainty, GLJ has estimated the CoDev at 19% and the CoDis at 90%. The corresponding chance of commerciality is 17%. Risked best estimate prospective resources have been estimated at 33.6 mmboe and the risked estimated cost to bring these resources on commercial production is $638 MM with an expected timeline of 7 to 14 years.
Wilrich Prospect:	Based on reservoir risk, development timing and limited Wilrich development on the land base, GLJ has estimated the CoDev at 35% and the CoDis at 85%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 22.2 mmboe and the risked estimated cost to bring these resources on commercial production is $218 MM with an expected timeline of 2 to 9 years.
West Pembina Glauconite Prospect:	Based on chance of discovery risk due to uncertainty regarding threshold for reservoir quality to support commercial development of resources with horizontal drilling, along with economic risk related to capital and operating cost uncertainty due to limited horizontal development in proximity to interest lands and chance of development risk related to corporate commitment and development timing. GLJ has estimated the CoDev at 34% and the CoDis at 90%. The corresponding chance of commerciality is 31%. Risked best estimate prospective resources have been estimated at 6.2 mmboe and the risked estimated cost to bring these resources on commercial production is $53 MM with an expected timeline of 6 to 12 years.
Drayton Valley Notikewin Prospect:	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 85%. The corresponding chance of commerciality is 60%. Risked best estimate prospective resources have been estimated at 4.6 mmboe and the risked estimated cost to bring these resources on commercial production is $66 MM. The expected development timeline is 9 to 11 years.
Saskatchewan Prospects	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 90% and the CoDis at 80%. The corresponding chance of commerciality is 72%. Risked best estimate prospective resources have been estimated at 3.3 mmboe and the risked estimated cost to bring these resources on commercial production is $60 MM with an expected timeline of 7 to 11 years.
Ferrier Falher Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 90%. The corresponding chance of commerciality is 54%. Risked best estimate prospective resources have been estimated at 2.7 mmboe and the risked estimated cost to bring these resources on commercial production is $23 MM with an expected timeline of 15 to 20 years.
Utikuma Gilwood Prospect	Based on reservoir risk, development timing and limited Gilwood development in the area, GLJ has estimated the CoDev at 60% and the CoDis at 50%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $3 MM with an expected timeline of 3 to 9 years.

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

Seebach Prospect	Based on risks associated with seal, trap, reservoir and charge along with development timing, GLJ has estimated the CoDev at 75% and the CoDis at 18%. The corresponding chance of commerciality is 14%. Risked best estimate prospective resources have been estimated at 7.8 mmboe and the risked estimated cost to bring these resources on commercial production is $40 MM with an expected timeline of 5 to 7 years.
Rachee Prospect	Based on risk of closure and data quality along with development timing, GLJ has estimated the CoDev at 80% and the CoDis at 80%. The corresponding chance of commerciality is 64%. Risked best estimate prospective resources have been estimated at 3.4 mmboe and the risked estimated cost to bring these resources on commercial production is $233 MM with an expected timeline of 9 to 13 years.
Malnoue Prospect	Based on reservoir, structure and trap risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 38%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $35 MM with an expected timeline of 8 to 12 years.
West Lavergne Prospect	Based on structure risk and development timing GLJ has estimated the CoDev at 80% and the CoDis at 70%. The corresponding chance of commerciality is 56%. Risked best estimate prospective resources have been estimated at 1.2 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM with an expected timeline of 4 years.
Champotran Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 80% and the CoDis at 67%. The corresponding chance of commerciality is 54%. Risked best estimate prospective resources have been estimated at 0.9 mmboe and the risked estimated cost to bring these resources on commercial production is $21 MM with an expected timeline of 1 to 11 years.
Vulaines Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 80% and the CoDis at 40%. The corresponding chance of commerciality is 32%. Risked best estimate prospective resources have been estimated at 0.6 mmboe and the risked estimated cost to bring these resources on commercial production is $14 MM with an expected timeline of 7 to 9 years.
Charmottes Prospect	Based on reservoir risk and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 50%. The corresponding chance of commerciality is 30%. Risked best estimate prospective resources have been estimated at 0.5 mmboe and the risked estimated cost to bring these resources on commercial production is $19 MM with an expected timeline of 10 to 12 years.
Bernet Prospect	Based on risks associated with reservoir, seal and trap along with economic factors, and development timing, GLJ has estimated the CoDev at 50% and the CoDis at 65%. The corresponding chance of commerciality is 33%. Risked best estimate prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $7 MM with an expected timeline of 4 to 5 years.

Vert Le Grand Prospect	Based on reservoir and structure risk along with development timing, GLJ has estimated the CoDev at 70% and the CoDis at 28%. The corresponding chance of commerciality is 20%. Risked best estimate prospective resources have been estimated at 0.2 mmboe and the risked estimated cost to bring these resources on commercial production is $4 MM with an expected timeline of 4 to 5 years.
Les Genets Prospect	Based on reservoir, seal and closure risk, along with economic factors and development timing, GLJ has estimated the CoDev at 60% and the CoDis at 16%. The corresponding chance of commerciality is 10%. Risked best estimate prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $1 MM with an expected timeline of 8 years.
North Acacias Prospect	Based on reservoir, seal and trap risk, along with economic factors and development timing, GLJ has estimated the CoDev at 70% and the CoDis at 39%. The corresponding chance of commerciality is 27%. Risked best estimate prospective resources have been estimated at 0.07 mmboe and the risked estimated cost to bring these resources on commercial production is $1 MM with an expected timeline of 4 to 5 years.

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

Wisselshorst A Prospect	Based on seal and trap risk along with development timing , GLJ has estimated the CoDev at 90%, and the CoDisc at 58%. The corresponding chance of commerciality is 52%. Risked Best Estimate Prospective resources have been estimated at 13.5 mmboe and the risked estimated cost to bring these resources on commercial production is $85.5MM with an expected timeline of 2 to 9 years.
Ihlow Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 71%, and the CoDisc at 51%. The corresponding chance of commerciality is 36%. Risked Best Estimate Prospective resources have been estimated at 6.6 mmboe and the risked estimated cost to bring these resources on commercial production is $46.6MM with an expected timeline of 5 to 7 years.
Wisselshorst B Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 50%. The corresponding chance of commerciality is 45%. Risked Best Estimate Prospective resources have been estimated at 5.5 mmboe and the risked estimated cost to bring these resources on commercial production is $42.7MM with an expected timeline of 5 to 12 years.
Weissenmoor South	Based on reservoir and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 36%. The corresponding chance of commerciality is 32%. Risked Best Estimate Prospective resources have been estimated at 4.2 mmboe and the risked estimated cost to bring these resources on commercial production is $15.9MM with an expected timeline of 3 to 8 years.
Simonswolde South Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 71%, and the CoDisc at 48%. The corresponding chance of commerciality is 34%. Risked Best Estimate Prospective resources have been estimated at 4.1 mmboe and the risked estimated cost to bring these resources on commercial production is $16MM with an expected timeline of 8 to 9 years.
Fallingbostel	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 29%. The corresponding chance of commerciality is 26%. Risked Best Estimate Prospective resources have been estimated at 3.4 mmboe and the risked estimated cost to bring these resources on commercial production is $29.5MM with an expected timeline of 3 to 9 years.
Hellwege	Based on reservoir and trap risk along with development timing, GLJ has estimated the CoDev at 90%, and the CoDisc at 40%. The corresponding chance of commerciality is 36%. Risked Best Estimate Prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $16.1MM with an expected timeline of 3 to 8 years.
Jeddeloh Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 38%, and the CoDisc at 32%. The corresponding chance of commerciality is 12%. Risked Best Estimate Prospective resources have been estimated at 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is $23.1MM with an expected timeline of 3 to 12 years.
Ohlendorf Prospect	Based on source and trap risk along with development timing, GLJ has estimated the CoDev at 58%, and the CoDisc at 30%. The corresponding chance of commerciality is 17%. Risked Best Estimate Prospective resources have been estimated at 2.4 mmboe and the risked estimated cost to bring these resources on commercial production is $11.1MM with an expected timeline of 9 to 13 years.
Uphuser Meer Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 47%, and the CoDisc at 51%. The corresponding chance of commerciality is 24%. Risked Best Estimate Prospective resources have been estimated at 1.7 mmboe and the risked estimated cost to bring these resources on commercial production is $8.3MM with an expected timeline of 6 to 7 years.
Simonswolde North Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 62%, and the CoDisc at 45%. The corresponding chance of commerciality is 28%. Risked Best Estimate Prospective resources have been estimated at 1.4 mmboe and the risked estimated cost to bring these resources on commercial production is $6.1MM with an expected timeline of 6 to 7 years.
Burgmoor Z5 Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 63%, and the CoDisc at 52%. The corresponding chance of commerciality is 33%. Risked Best Estimate Prospective resources have been estimated at 0.7mmboe and the risked estimated cost to bring these resources on commercial production is $1.1MM with an expected timeline of 1 year.
Widdernhausen East Prospect	Based on reservoir, seal and trap risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDisc at 44%. The corresponding chance of commerciality is 14%. Risked Best Estimate Prospective resources have been estimated at 0.4 mmboe and the risked estimated cost to bring these resources on commercial production is $2.7MM with an expected timeline of 7 to 12 years.
Wellie Prospect	Based on reservoir, seal and source risk along with development timing, GLJ has estimated the CoDev at 32%, and the CoDisc at 20%. The corresponding chance of commerciality is 6%. Risked Best Estimate Prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3.3MM with an expected timeline of 10 years.

Otterstedt Prospect	Based on reservoir, seal and trap risk along with development timing , GLJ has estimated the CoDev at 46%, and the CoDisc at 34%. The corresponding chance of commerciality is 16%. Risked Best Estimate Prospective resources have been estimated at 0.3 mmboe and the risked estimated cost to bring these resources on commercial production is $3.5MM with an expected timeline of 8 to 13 years.
Ostervesede Prospect	Based on reservoir and seal risk along with development timing, GLJ has estimated the CoDev at 23%, and the CoDisc at 25%. The corresponding chance of commerciality is 6%. Risked Best Estimate Prospective resources have been estimated at 0.1 mmboe and the risked estimated cost to bring these resources on commercial production is $0.7MM with an expected timeline of 7 to 10 years.

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

Prospective resources for Netherlands East have been estimated based on the individual areas outlined below. GLJ has estimated the aggregate CoDev at 25% and the aggregate CoDis at 41%. The corresponding chance of commerciality is 10%. Risked best estimate prospective resources have been estimated at an aggregate of 12.1 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of 83 MM with an expected timeline of 2 to 15 years.

- Chance of discovery provided for 109 prospective reservoir targets across 91 prospective locations. Risk primarily associated with presence of reservoir and seal as region proven to have adequate source, migration and timing to charge target reservoirs.
- Chance of development risked to account for company commitment and development timing, anticipated timing for permitting in respective licenses and distance to export (i.e. pipeline/facility requirements to transport gas to sales point). Chance of development is also a function of prospect size.
- 65 prospects summed probabilistically across 13 development groups to appropriately allocate required infrastructure capital across multiple prospective targets within reasonable proximity. As probabilistic summation of the groups resulted in strong economic indicators, no further minimum economic field size calculations were applied as they were considered to have nominal impact.

Prospective resources for Netherlands West have been estimated based on the factors outlined below. GLJ has estimated the aggregate CoDev at 41% and the aggregate CoDis at 28%. The corresponding chance of commerciality is 12%. Risked best estimate prospective resources have been estimated at an aggregate of 2.9 mmboe and the risked estimated cost to bring these resources on commercial production is an aggregate of$ 43 MM with an expected timeline of 2 to 12 years.

- Chance of discovery provided for 25 prospective reservoir targets across 21 prospective locations. Risk primarily associated with presence of reservoir and seal as region proven to have adequate source, migration and timing to charge target reservoirs.
- Chance of development risked to account for company commitment and development timing, anticipated timing for permitting in respective licenses and distance to export (i.e. pipeline/facility requirements to transport gas to sales point). Chance of development is also a function of prospect size.
- 17 prospects summed probabilistically across 5 development groups to appropriately allocate required infrastructure capital across multiple prospective targets within reasonable proximity. As probabilistic summation of the groups resulted in strong economic indicators no further minimum economic field size calculations were applied as they were considered to have nominal impact.

ABOUT VERMILION

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. Our business model emphasizes organic production growth augmented with value-adding acquisitions, along with providing reliable and increasing dividends to investors. Vermilion is targeting growth in production primarily through 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 through oil drilling and workover programs in France and Australia. Vermilion currently holds an 18.5% working interest in the Corrib gas field in Ireland. Vermilion currently pays a monthly dividend of Canadian $0.215 per share, which provides a current yield of approximately 6.0%.

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. We have been recognized as a top decile performer amongst Canadian publicly listed companies in governance practices, as a Climate Leadership level (A-) performer by the CDP, and a Best Workplace in the Great Place to Work® Institute's annual rankings in Canada, France and the Netherlands. In addition, Vermilion emphasizes strategic community investment in each of our operating areas.

Employees and directors hold approximately 6.5% of our fully diluted shares, are committed to consistently delivering superior rewards for all stakeholders, and have delivered over 20 years of market outperformance. Vermilion trades on the Toronto Stock Exchange and the New York Stock Exchange under the symbol VET.

Natural gas volumes have been converted on the basis of six thousand cubic feet of natural gas to one barrel equivalent of oil. 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.

Netbacks and Operating Recycle Ratio are measures that do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable with the calculations of similar measures for other entities. "Operating Recycle Ratio" is a measure of capital efficiency calculated by dividing the Operating Netback by the cost of adding reserves (F&D cost). "Netbacks" are per boe and per Mcf measures used in operational and capital allocation decisions. "Operating Netback" is calculated as 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. F&D (finding and development) costs are used as a measure of capital efficiency and are calculated by dividing the applicable capital expenditures for the period, including the change in undiscounted future development capital, by the change in the reserves, incorporating revisions and production, for the same period.

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