RAZOR ENERGY CORP.
ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2019

April 28, 2020

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GLOSSARY

Certain terms and abbreviations used in this Annual Information Form are defined below:

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended, including the regulations promulgated thereunder.

"**Action**" has the meaning attributed thereto in "*Legal Proceedings and Regulatory Actions*".

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

"**AIF**" means this annual information form dated April 28, 2020 for the financial year ended December 31, 2019.

"**AIMCo**" means Her Majesty the Queen in Right of Alberta by its agent, Alberta Investment Management Corporation.

"**Amended Term Loan Facility**" has the meaning attributed thereto in "*Three-Year History*".

"**Arrangement**" has the meaning attributed thereto in "*Name, Address and Incorporation"*.

"**Board**" or "**Board of Directors**" means the board of directors of the Company, as constituted from time to time, including where applicable, any committee thereof.

"**Common Shares**" means the common shares in the capital of the Company.

"**Consolidation**" means the share consolidation of the Company on the basis of one post-Consolidation Common Share for every 20 pre-Consolidation Common Shares.

"**Company**" or "**Razor**" means Razor Energy Corp.

"**CPC**" means a corporation:

a. that has been incorporated or organized in a jurisdiction in Canada;
b. that has filed and obtained a receipt for a preliminary CPC prospectus from one or more of the securities regulatory authorities in compliance with the Policy 2.4 of the TSXV; and
c. in regard to which the completion of the Qualifying Transaction has not yet occurred.

"**Kaybob Acquisition**" means the acquisition of certain oil and gas assets located in the Kaybob area of Alberta from an arm's length public oil and gas company for aggregate consideration of $12.3 million, including customary closing and post-closing reconciliation adjustments.

"**Kaybob Triassic Unit 1 and 2 Working Interest Acquisition**" means series of acquisitions of additional working interest in the Kaybob Triassic Unit 1 and 2 for total cash consideration of $9.6 million, including customary closing and post-closing reconciliation adjustments.

"Little Rock Acquisition" means the acquisition of Little Rock Resources Ltd. ("Little Rock"), which owned certain oil and gas assets located in southern Alberta, for aggregate consideration of $13.2 million, including the issuance of $9.6 million in Common Shares and the assumption of Little Rock's net debt of $3.6 million.

"**NI 51-102**" means National Instrument 51-102 - *Continuous Disclosure Obligations* of the Canadian Securities Administrators.

"**Qualifying Transaction**" means a transaction where a CPC acquires Significant Assets other than cash, by way of purchase, amalgamation, merger or arrangement with another company or by other means and, for the purposes of this AIF, the reverse takeover of the Company by Razor Private.

"**Razor Private**" means Razor Energy Corp., a private company incorporated under the ABCA on June 14, 2016.

"**Shareholders**" means the holders of Common Shares.

"**Sproule Report**" means the independent engineering evaluation of the oil and natural gas reserves attributable to the properties of the Company prepared by Sproule dated February 24, 2020 and effective December 31, 2019.

"**Swan Hills Acquisition**" means the acquisition of certain oil and gas assets located in the Swan Hills area of Alberta from an arm's length public oil and gas company for aggregate consideration of $15.6 million, including customary closing and post-closing reconciliation adjustments.

"**Term Loan Facility**" has the meaning attributed thereto in "*Three Year History - Financial Year Ended December 31, 2018*".

"**TSXV**" or "**Exchange**" means the TSX Venture Exchange.

"**Vector**" means Vector Resources Inc., a CPC company incorporated under the *Business Corporations Act* (Ontario).

"**Vector Shares**" means the Common Shares prior to the closing of the Arrangement and prior to giving effect to the Consolidation.

CONVENTIONS

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information with respect to the Company has been presented in Canadian dollars in accordance with International Financial Reporting Standards ("**IFRS**"). The information in this AIF is stated as at December 31, 2019, unless otherwise indicated.

ABBREVIATIONS

	Oil and Natural Gas Liquids		*Natural Gas*
Bbl	barrel	GJ	gigajoule
Bbls	barrels	Mcf	thousand cubic feet
BOPD	barrel of oil per day	Mmcf	million cubic feet
Mbbl	thousand barrels	Mcf/d	thousand cubic feet per day
Bbls/d	barrels per day	Mmcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBTU	million British Thermal Units

Other

AECO	Alberta Energy Company's natural gas storage facility located at Suffield, Alberta.
API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
m3	cubic metres
MBOE	1,000 barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$000 or M$	thousands of dollars

CONVERSION

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

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

NOTE ON SHARE REFERENCES

The Common Shares were consolidated on the basis of one post-Consolidation Common Share for every 20 Vector Shares on January 31, 2017. References in this AIF to Common Shares are on a post-Consolidation basis. References in this AIF to pre-Consolidation Common Shares or Vector Shares refer to the Common Shares prior to the Consolidation. Readers should divide any referenced number of Vector Shares by 20 to arrive at the equivalent number of Common Shares.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF may constitute forward-looking statements. These statements relate to future events or the Company's future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this AIF should not be unduly relied upon by investors. These statements speak only as of the date of this AIF and are expressly qualified, in their entirety, by this cautionary statement.

Forward-looking statements or information in this AIF include, but are not limited to, the characteristics of the Company's oil and natural gas interests, future production levels, projection of market prices, capital expenditures, exploration plans, development plans, acquisition and disposition plans and the timing thereof, operating and other costs, world-wide supply and demand for petroleum products, royalty rates and treatment under governmental regulatory regimes. In addition, this AIF may contain forward-looking statements attributed to third party industry sources.

In particular, this AIF contains forward-looking statements pertaining to the following:

- future revenues and costs (including royalties) and revenues and costs per commodity unit;
- recovery factors;
- the performance characteristics of the Company's oil and natural gas properties;
- well completions and the timing thereof;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production and timing of results therefrom;
- future development and growth prospects;
- ability to meet current and future obligations;
- future sources of funding for capital programs and future availability of such sources;
- future asset acquisitions or dispositions;
- future development costs and operating costs:
- development plans;

- our ability to continue as a going concern in the future;
- anticipated land expiries;
- treatment under governmental regulatory regimes and tax laws;
- the ability to obtain financing on acceptable terms or at all; and
- currency, exchange and interest rates.

With respect to forward-looking statements contained in this AIF, the Company has made assumptions regarding, among other things:

- the Company's ability to continue as a going concern going forward and realize our assets and discharge our liabilities in the normal course of business;
- oil and natural gas production levels;
- the success of the Company's operations and exploration and development activities;
- prevailing climatic conditions, commodity prices and exchange rates;
- the impact of increasing competition;
- availability of skilled labour, services and drilling equipment;
- timing and amount of capital expenditures;
- the legislative and regulatory environments of the jurisdictions where the Company carries on business or has operations;
- conditions in general economic and financial markets;
- availability of drilling and related equipment;
- availability of pipeline capacity and other major facilities;
- royalty rates and future operating costs;
- access to market for the Company's production; and
- the Company's ability to obtain additional financing on satisfactory terms.

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this AIF:

- the possibility that we are not able to continue as a going concern and realize our assets and discharge our liabilities in the normal course of business;
- the global public health crises in respect of the outbreak of the novel coronavirus (COVID-19), including volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people;
- volatility in market prices for oil and natural gas, interest and exchange rates;
- uncertainties associated with estimating oil and natural gas reserves;
- the risks of the oil and gas industry, such as operational risks and market demand;
- pipeline and third-party facility capacity constraints and access to sales markets;
- the ability of management to execute its business plan;
- governmental regulation of the oil and gas industry, including environmental regulation;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- geological, technical, drilling and processing problems;
- exploration and development activities are capital intensive and involve a high degree of risk;
- risks and uncertainties involving geology of oil and gas deposits;
- risks inherent in marketing operations, including credit risk;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Company's capital expenditures;
- stock market volatility and market valuations;
- failure to realize the anticipated benefits of acquisitions and dispositions;
- unanticipated operating events which could reduce production or cause production to be shut-in or delayed;
- hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- the ability to add production and reserves through development and exploration activities;
- uncertainties in regard to the timing of exploration and development activities;
- changes in general economic, market and business conditions;
- the effect of litigation proceedings, including the Action, on the Company's business;

- the possibility that government policies or laws, including laws and regulations related to the environment, may change or governmental approvals may be delayed or withheld;
- uncertainty in amounts and timing of royalty payments;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third-party consents and approvals, as and when required;
- the availability of capital on acceptable terms or at all;
- cyber-security issues;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel; and
- the other factors considered under "*Risk Factors*" below.

Statements relating to "reserves" are deemed to be forward-looking statements or information, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitable in the future. There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties and classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Company with respect to these reserves will vary from such estimates, and such variances could be material.

The Company has included the above summary of assumptions and risks related to forward-looking information provided herein in order to provide investors with a more complete perspective on the Company's current and future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained herein, and the documents incorporated by reference herein, are expressly qualified by this cautionary statement. Except as required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements and readers should also carefully consider the matters discussed under the heading "Risk Factors" below.

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

Caution Respecting BOE
In this Annual Information Form, the abbreviation BOE means a barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency conversion ratio of 6 Mcf to 1 BOE, utilizing a conversion ratio of 6 Mcf to 1 BOE may be misleading as an indication of value.

Non-IFRS Measures
Certain financial measures in this document or in documents incorporated by reference herein do not have a standardized meaning as prescribed by IFRS and are therefore considered non-IFRS measures. These measures, such as netbacks, may not be comparable to similar measures presented by other issuers. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

NAME, ADDRESS AND INCORPORATION

The Company was incorporated under the laws of the Province of Ontario as "2236235 Ontario Inc." on March 5, 2010. On April 15, 2011, the Company filed articles of amendment to change its name from "2236235 Ontario Inc." to "Vector Resources Inc." On June 29, 2011, the Company filed articles of amendment to remove share transfer restrictions in its articles.

On September 28, 2011, the Company completed its initial public offering. The Company was classified as a CPC as described in the policies of the TSXV. As a result, Vector's business was to identify and evaluate businesses and assets with a view to completing a qualifying transaction.

On January 31, 2017, the Company completed its qualifying transaction by way of plan of arrangement (the "**Arrangement**"), whereby Razor Private, a private company incorporated on June 14, 2016, completed a reverse take-over of the Company (the "**Qualifying Transaction**"). On January 31, 2017, the Company completed the Consolidation and changed its name from "Vector Resources Inc." to "Razor Energy Corp." On February 3, 2017, the Company and Razor Private were amalgamated and continued as "Razor Energy Corp." On February 3, 2017, the Company completed a continuance of the Company from Ontario into Alberta under the ABCA.

The Company is a reporting issuer in British Columbia, Alberta and Ontario. The Common Shares are listed on the TSXV under the trading symbol "RZE".

The Company's head office is located at 800, 500 - 5th Avenue S.W., Calgary, Alberta, T2P 3L5. The registered office of the Company is located at 4300, 888 - 3rd Street S.W., Calgary, Alberta, T2P 5C5.

As at the date hereof the Company has three wholly-owned subsidiaries, Razor Resources Corp., Blade Energy Services Corp., and FutEra Power Corp. All subsidiaries are incorporated under the laws of the Province of Alberta.

GENERAL DEVELOPMENT OF THE BUSINESS

Three-Year History

Financial Year Ended December 31, 2017

On January 31, 2017, the Company completed the Arrangement, which constituted the Company's Qualifying Transaction. Pursuant to the Arrangement, each common share of Razor Private was exchanged for 2,042.13 Vector Shares. Former shareholders of Razor Private received an aggregate of 179,525,708 Common Shares of the Company on a pre-Consolidation basis.

On January 31, 2017, the Company secured a non-revolving term loan facility from AIMCo for a principal amount of $30.0 million (the "**Term Loan Facility**"). The Term Loan Facility has a four-year term with an interest rate of 10% and is payable semi-annually. A portion of the Term Loan Facility was used by the Company to fund the purchase price in respect of the Swan Hills Acquisition. The remaining proceeds of the Term Loan Facility were be used by the Company to fund its development program and for general corporate purposes. The Company also issued Common Shares to AIMCo, representing approximately 10.05% of the Common Shares, at the time of issuance, as additional consideration for the Term Loan Facility.

On January 31, 2017, the Company completed the Swan Hills Acquisition, pursuant to which the Company acquired certain oil and gas interests in the Swan Hills area of Alberta for aggregate cash consideration of $15.8 million, including customary closing and post-closing reconciliation adjustments.

On January 31, 2017, the Company completed the Consolidation and filed articles of amendment to change its name from "Vector Resources Inc." to "Razor Energy Corp.".

On May 15, 2017, the Company closed a prospectus financing of 5,750,000 subscription receipts at a price of $3.00 per subscription receipt for gross proceeds of $17.3 million (net proceeds of $15.5 million).

On May 24, 2017, the Company completed the Kaybob Acquisition, pursuant to which the Company acquired certain oil and gas interests in the Kaybob area of Alberta for aggregate cash consideration of $12.3 million, including customary closing and post-closing reconciliation adjustments. In connection with the closing of the Kaybob Acquisition, on May 24, 2017, each subscription receipt was converted to one common share of the Company and one-half of one common share purchase warrant of the Company. Each whole warrant was exercisable into one common share of the Company at an exercise price of $3.50 per common share and expired on May 24, 2018.

On December 18, 2017, the Company acquired additional working interest positions to consolidate its existing Kaybob Triassic Units 1 & 2 for aggregate cash consideration of $4.6 million, including customary closing and post-closing reconciliation adjustments.

Financial Year Ended December 31, 2018

On January 15, 2018, the Company increased its existing Term Loan Facility by $15.0 million for an amended principal amount of $45.0 million (the "Amended Term Loan Facility"). The terms of the Amended Term Loan Facility are materially unchanged from the Term Loan Facility. Principal continues to be due January 31, 2021 with an interest rate of 10%, payable semi-annually. As consideration for the Amended Term Loan Facility, 255,600 Common Shares were issued to AIMCo.

On January 15 and June 20, 2018, the Company acquired additional working interest positions to further consolidate its existing Kaybob Triassic Units 1 & 2 for aggregate cash consideration of $5.0 million, including customary closing and post-closing reconciliation adjustments.

On September 5, 2018, the Company declared a special cash dividend of $0.165 per Common Share payable on October 5, 2018 to Shareholders of record on October 2, 2018.

On October 1, 2018, the Company announced its transition to a dividend paying company and declared its first monthly cash dividend of $0.0125 per Common Share payable on October 31, 2018 to Shareholders of record on October 15, 2018. Monthly dividends were declared and paid in November and December 2018.

Financial Year Ended December 31, 2019

On February 6, 2019, the Company completed a non-monitory asset swap whereby Razor increased its working interest position in its Virginia Hills Unit 1 and completely disposed its working interest in Kaybob Beaverhill Lake Unit 1. This transaction increased the Company's working interest position in Virginia Hills Unit 1 to 100%.

On September 11, 2019, the Company completed the Little Rock Acquisition, pursuant to which the Company acquired certain oil and gas assets located in southern Alberta, for aggregate consideration of $13.2 million, including the issuance of $9.6 million in Common Shares and the assumption of Little Rock's net debt of $3.6 million. This acquisition provided the Company with a second core region in southern Alberta, with significant presence in the Jumpbush, Majorville, Badger, Enchant and Chin Coulee areas.

During 2019, the Company declared and paid a dividend of $0.0125 per Common Share each month, representing total dividends paid of $0.15 per Common Share for the year.

Significant Acquisitions

The Company has not completed any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS OF THE COMPANY

The Company is a growth oriented light oil weighted company operating in Alberta. The Company is focused on growing through corporate and asset acquisitions, exploitation and improvement of existing production and infrastructure, complemented by development and exploration drilling. Razor's full-cycle business plan supports its position as a growth junior oil and natural gas production company.

As part of its growth strategy, Razor continues to strategically evaluate and search out oil and natural gas properties that will result in meaningful reserve and production additions. The Company prefers to concentrate capital to higher quality, longer life reservoirs in proved areas that offer existing infrastructure, low cost drilling opportunities, year round access and operational control. Razor's existing core operating properties in Alberta will continue to be optimized, developed, and expanded through a detailed technical analysis of available data, including reservoir characteristics, original crude oil and natural gas in place, recovery factors and the application of exploitation reactivations, re-entries, drilling and enhanced recovery techniques.

In each of its core areas, Razor's growth strategy is to:

1. acquire and consolidate complementary prospective lands and drilling location opportunities;
2. optimize areas with a combination of reactivating production, re-entering existing wellbores, modifying existing secondary recovery schemes, reconfiguring infrastructure, generally lowering operating costs, and improving safety and environmental stewardship;
3. build a sufficient inventory of land and drilling locations to support up to five years of technically viable field operational activities;
4. manage uncertainty through the technical and operating experience Razor has in each of the areas in which it operates;
5. attract skilled and experienced labour and acquire equipment to vertically integrate certain service functions where Razor has a defined internal market; and
6. explore and execute on power related projects for internal consumption and third-party sales.

To execute its business plan, Razor requires: (i) access to land and additional opportunities; (ii) appropriate commercial terms; (iii) access to services and goods for operations; (iv) acquisition and operational success; and (v) timely financing for all such activities.

Specialized Skill and Knowledge

The Company relies on the specialized skill and knowledge of its permanent staff to compile, interpret and evaluate technical data, drill and complete wells, design and operate production facilities and numerous additional activities required to explore for and produce oil and natural gas. From time to time, the Company employs consultants and other service providers to provide complementary experience and expertise to carry out its oil and natural gas operations effectively. It is the belief of management of Razor that its officers and employees, who have significant technical, operational and financial experience in the oil and gas industry, hold the necessary skill sets to successfully execute Razor's business strategy in order to achieve its corporate objectives.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. The Company competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include resource companies that have greater financial resources, staff and facilities than those of the Company. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Company believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development. See *"Risk Factors - Competition"*.

Cyclical and Seasonal Nature of Industry

Razor's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on Razor's financial condition. Furthermore, the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. See *"Risk Factors - Seasonality"*.

Environmental

The Company believes that it is in compliance with applicable existing environmental laws and regulations and is not aware of any proposed environmental legislation or regulations with which it would not be in material compliance. Procedures are put in place to ensure that the utmost care is taken in the day-to-day management of Razor's oil and gas properties. However, in the future, the natural resources industry may become subject to more stringent environmental protection rules. This could increase the cost of doing business and may have a negative impact on future earnings. See *"Industry Conditions"* and *"Risk Factors".*

Employees

As at December 31, 2019, the Company had 44 employees (comprised of 29 head office and 15 field employees), and 14 contract employees in the field. In addition, the Company utilizes the services of contractor operators in its field operations.

Reorganizations

Other than as disclosed in *"General Development of the Business - Financial Year Ended December 31, 2017"*, there have been no material reorganizations of the Company within the three most recently completed financial years or completed during or proposed for the current financial year.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data and Other Information as of Financial Year Ended December 31, 2019

The reserves data set forth below is based upon an evaluation by Sproule Associates Limited ("Sproule") and contained in the the Sproule Report dated February 24, 2020. The effective date of this report is December 31, 2019 and was prepared for Razor between December 2019 and February 2020. The Sproule Report summarizes the crude oil, natural gas liquids and natural gas reserves of Razor and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH") and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Razor believes is important to the readers of this information. The following tables provide summary information presented in the Sproule Report effective December 31, 2019 and based on the Sproule December 31, 2019 price forecast.

As of the date hereof, Razor's reserves are located in the province of Alberta.

The Report on Reserves Data by Sproule and the Report of Management and Directors on Oil and Gas Disclosure are attached as Schedule A and Schedule B, respectively, to this AIF.

New And Revised Reserves Evaluation Guidelines And Best Practices For Industry Stakeholders

In October 2019, the Calgary Chapter of the Society of Petroleum Evaluation Engineers ("SPEE") and associated industry professionals updated the COGEH. These updates clarify and streamline previous guideline recommendations initiated in 2018 and offer additional guidance regarding Canadian reserves evaluations.

For the second year in a row, Razor continues to be an industry leader, alongside Sproule, by incorporating industry best practice by including all abandonment, decommissioning and reclamations costs ("ADR") and inactive well costs ("IWC") into the Sproule Report.

With respect to ADR Costs, the discounted year-end 2019 was $32.5 million, an increase of $4.4 million from year-end 2018 ($28.1 million). This increase is attributable to integrating ADR costs associated with the acquisition of "Little Rock".

With respect to IWC Costs, the discounted year-end 2019 was $28.8 million, an increase of $7.6 million from year-end 2018 ($21.2 million). This increase is primarily due to integrating the acquisition of Little Rock.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the Company's reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Razor's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

SUMMARY OF OIL AND GAS RESERVES
(FORECAST PRICES AND COSTS)
AS OF December 31, 2019

	Light & Medium Oil		Heavy Oil		Conventional Natural Gas		Natural Gas Liquids		Barrels of Oil Equivalent	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mmcf)	(Mmcf)	(Mbbl)	(Mbbl)	(MBOE)	(MBOE)
Proved										
Developed producing	7,029	5,777	209	191	9,956	9,390	2,246	1,769	11,144	9,302
Developed non-producing	1,859	1,557	66	63	2,307	2,196	739	587	3,048	2,573
Undeveloped	1,544	1,419	280	246	629	596	137	124	2,067	1,889
Total Proved	**10,432**	**8,752**	**555**	**500**	**12,892**	**12,182**	**3,122**	**2,480**	**16,259**	**13,764**
Total Probable	2,893	2,417	127	108	3,683	3,482	859	718	4,492	3,823
Total Proved plus Probable	**13,325**	**11,169**	**682**	**608**	**16,575**	**15,664**	**3,981**	**3,198**	**20,751**	**17,587**

Notes:
(1) Columns may not add due to rounding.
(2) Natural gas volumes include associated and non-associated gas.
(3) Natural gas is converted to a BOE at a ratio of six thousand standard cubic feet to one barrel of oil.

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE
(FORECAST PRICES AND COSTS)
AS OF December 31, 2019

	Before Income Tax Discounted at Various Rates				Unit Value Before Income Tax
	0%	5%	10%	15%	Discounted at 10%
Description	**M$**	**M$**	**M$**	**M$**	**$/BOE**
Proved					
Producing	37,940	119,200	116,832	105,004	12.56
Developed non-producing	65,715	49,791	39,409	32,216	15.32
Undeveloped	55,666	42,705	33,019	25,752	17,48
Total Proved	**159,321**	**211,696**	**189,260**	**162,972**	**13.75**
Total Probable	124,635	77,890	53,460	39,056	13.98
Total Proved plus Probable	**283,956**	**289,586**	**242,720**	**202,028**	**13.80**

Notes:
(1) Utilizes Sproule's price forecast as of December 31, 2019 as detailed below.
(2) Values are net of ADR and IWC.
(3) Columns may not add due to rounding.
(4) Unit values are based upon the Company's net reserves

	After Income Tax Discounted at Various Rates				Unit Value Before Income Tax
	0%	5%	10%	15%	Discounted at 10%
Description	**M$**	**M$**	**M$**	**M$**	**$/BOE**
Proved					
Producing	20,425	105,989	106,534	96,757	11.45
Developed Non-producing	50,916	38,276	30,110	24,485	11.70
Undeveloped	42,375	31,824	23,936	18,044	12.67
Total Proved	**113,716**	**176,089**	**160,580**	**139,286**	**11.67**
Total Probable	100,024	60,927	41,072	29,580	10.74
Total Proved plus Probable	**213,740**	**237,016**	**201,652**	**168,866**	**11.47**

Notes:
(1) Utilizes Sproule's price forecast as of December 31, 2019 as detailed below.
(2) Values are net of ADR and IWC.
(3) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
(FORECAST PRICES AND COSTS)
AS OF December 31, 2019

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment / Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Tax (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved	1,136,073	173,979	543,553	50,696	208,523	159,322	45,607	113,715
Total Proved Plus Probable	1,481,552	226,947	693,795	67,495	209,358	283,957	70,218	213,739

FUTURE NET REVENUE BY PRODUCT TYPE
(FORECAST PRICES AND COSTS)
AS OF December 31, 2019

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE TAXES (discounted at 10%/ year) (M$)	UNIT VALUE BEFORE INCOME TAX (discounted at 10%/ year) ($/boe)
Proved	Light and Medium Crude Oil including solution gas liquids	176,537	13.87
	Heavy Crude Oil including solution gas liquids	11,377	19.55
	Conventional Natural Gas including associate by-products	1,347	2.97
		189,261	
Proved Plus Probable	Light and Medium Crude Oil including solution gas liquids	226,419	13.92
	Heavy Crude Oil including solution gas liquids	14,450	20.40
	Conventional Natural Gas including associate by-products	1,851	3.03
		242,720	

Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were Sproule's forecasts, as at December 31, 2019, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
(FORECAST PRICES AND COSTS)
AS OF December 31, 2019

Year	WTI Oil ($US/Bbl)	Edmonton Light Sweet Oil ($Cdn/Bbl)	Hardisty Bow River ($Cdn/Bbl)	Natural Gas AECO ($Cdn/MMBTU)	Exchange Rate ($US/$CDN)
Forecast					
2020	61.00	73.84	61.29	2.04	0.76
2021	65.00	78.51	64.77	2.27	0.77
2022	67.00	78.73	64.55	2.81	0.80
2023	68.34	80.30	65.85	2.89	0.80
2024	69.71	81.91	67.16	2.98	0.80
2025	71.10	83.54	68.51	3.06	0.80
2026	72.52	85.21	69.88	3.15	0.80
2027	73.97	86.92	71.27	3.24	0.80
2028	75.45	88.66	72.70	3.33	0.80
2029	76.96	90.43	74.15	3.42	0.80
Thereafter 2% inflation rate					

Notes:
(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.4% sulphur.
(2) Light Sweet Crude 40 degrees API, 0.3% sulphur at Edmonton.
(3) Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate. The plant gate price represents the price before raw gathering and processing charges are deducted.

Weighted average historical prices realized by the Company for the year ended December 31, 2019, was $68.34/Bbl for light crude oil, $60.61/Bbl for heavy oil, $26.80/Bbl for NGLs and $1.54/Mcf for natural gas.

	Q4-2019	Q3-2019	Q2-2019	Q1-2019	Q4-2018	Q3-2018	Q2-2018	Q1-2018
Average selling price								
Oil price ($/bbl)	67.59	64.19	76.48	65.10	43.63	80.80	79.71	69.76
NGL price ($/bbl)	23.82	24.24	28.14	30.98	28.86	35.70	34.37	35.89
Gas price ($/mcf)	1.69	1.01	1.06	2.56	2.03	1.86	1.74	2.42
Benchmark prices and foreign exchange rates								
OIL ($/bbl)								
WTI (USD)	56.94	56.44	59.80	54.83	59.10	69.75	68.05	62.91
WTI (CAD)	75.16	74.54	80.00	72.91	77.98	91.17	87.88	79.57
CAD/USD EXCHANGE RATE	0.76	0.76	0.75	0.75	0.76	0.76	0.78	0.79
WTI vs Light Sweet Edmonton Oil differential (CAD/bbl)	(7.19)	(6.22)	(6.16)	(6.57)	(37.40)	(12.63)	(8.98)	(7.27)
NATURAL GAS (CAD/mcf)								
AECO NGX AB-5a	2.49	0.84	1.02	2.59	1.57	1.19	1.25	2.08
AECO NGX AB-7a	2.36	1.04	1.17	1.98	1.90	1.35	1.04	1.87

Estimated ADR costs related to a working interest have been taken into account by Sproule for all active wells, inactive wells and facilities in determining the future net revenues. In addition, Sproule has also taken into account IWC related to a working interest in all inactive wells in determining the future net revenues.

The following table summarizes ADR and IWC deducted in the estimation of Razor's future net revenues before income tax discounted at various rates and escalated as per Sproule's December 31, 2019 price forecast. These expenditures are expected to occur between 2020 and 2075.

	Discounted at Various Rates			
	0%	**5%**	**10%**	**15%**
Description	M$	M$	M$	M$
Abandonment, decommissioning and reclamation costs ("ADR")	205,557	65,537	32,472	20,945
Inactive well costs ("IWC")	45,855	35,717	28,833	23,976
Total	**251,412**	**101,254**	**61,305**	**44,921**

The forecast price and cost assumptions assume the continuance of current laws and regulations.

Reconciliations of Changes in Reserves and Future Gross Revenue

Reserve Reconciliation

The following tables reconcile the Company's reserves from December 31, 2018 to December 31, 2019, using forecast prices and costs. Key highlights include:

- Acquisitions is due the to acquisition of "Little Rock".
- Technical Revisions include well performance adjustments and reserves category changes. The negative revision in the Light and Medium Oil for Proved Company Gross Reserves was offset by the positive revision in the Natural Gas Liquids.
- As a result of lower oil price forecasts year over year, Razor observed a negative impact on the Economic Factors category.

Proved Company Gross Reserves	**Light and Medium Oil (Mbbl)**	**Heavy Oil (Mbbl)**	**Conventional Natural Gas (Mmcf)**	**Proved (MBOE)**	**Proved plus probable (MBOE)**
Opening balance, beginning of year	**10,881**	—	**9,054**	**3,008**	**15,397**
Acquisitions	1,099	614	4,277	62	2,488
Dispositions	(1)	—	—	0	(1)
Technical Revisions	(382)	—	1,596	475	359
Economic Factors	(232)	—	(239)	(92)	(378)
Less Production	(932)	(60)	(1,713)	(331)	(1,608)
Total Reserves, end of year	**10,432**	**555**	**9,956**	**3,122**	**16,258**

Probable Company Gross Reserves	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Conventional Natural Gas (Mmcf)	Natural Gas Liquids (Mbbl)	Total Oil Equivalent (MBOE)
Opening balance, beginning of year	**3,410**	**0**	**2,844**	**941**	**4,826**
Acquisitions	219	127	1,090	15	543
Dispositions	0	0	0	0	0
Technical Revisions	(711)	0	(198)	(65)	(828)
Economic Factors	(26)	0	(135)	(14)	(48)
Production	0	0	0	0	0
Total Reserves, end of year	**2,893**	**127**	**6,619**	**859**	**4,492**

Proved Plus Probable Company Gross Reserves	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Conventional Natural Gas (Mmcf)	Natural Gas Liquids (Mbbl)	Total Oil Equivalent (MBOE)
Opening balance, beginning of year	**14,291**	**0**	**11,898**	**3,949**	**20,223**
Acquisitions	1,318	741	5,367	77	3,031
Dispositions	(1)	0	0	0	(1)
Technical Revisions	(1,093)	0	1,398	410	(469)
Economic Factors	(258)	0	(374)	(106)	(426)
Production	(932)	(60)	(1,713)	(331)	(1,608)
Total Reserves, end of year	**13,325**	**682**	**16,575**	**3,981**	**20,750**

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in COGEH. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved undeveloped reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101.

Proved undeveloped reserves were assigned to two vertical wells in the Montney formation in Kaybob, two vertical and ten horizontal wells in the Beaverhill Lake formation in Swan Hills, 3 Mannville horizontal wells in Badger and two Glauconitic horizontal wells in Jumpbush.

An additional five horizontal wells in the Beaverhill Lake formation in Swan Hills were assigned probable undeveloped reserves.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

Razor does not anticipate any unusually high development costs or operating costs, any unusually high abandonment and reclamation costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Razor's future net revenue attributable to the reserve categories noted below:

Year	Forecast Development Costs (M$)	
	Proved Reserves	**Proved Plus Probable Reserves**
2020	9,152	9,738
2021	19,154	19,154
2022	19,870	36,083
Thereafter	2,250	2,250
Total Undiscounted	**50,696**	**67,495**
Total Discounted at 10%	**43,183**	**56,893**

Future development costs are capital expenditures required in the future for Razor to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $50.7 million for proved reserves and $67.5 million for proved plus probable reserves (in each case based on forecast prices and costs).

On an ongoing basis, Razor will use internally generated cash flow from operations, debt and new equity issues, if available on favourable terms, to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for Razor.

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGEH. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered that proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable or production.

The following tables disclose, by each product type, the volumes of proved and probable undeveloped reserves that were first attributed by Sproule in each of the most recent three financial years.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbl)		**Heavy Oil (Mbbl)**		**Conv. Natural Gas (MMcf)**		**Natural Gas Liquids (Mbbl)**		**Total (Mboe)**	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2017	419	419	0	0	376	376	66	66	547	547
2018	347	1,382	0	0	195	424	53	116	433	1,569
2019	190	1,544	280	280	266	629	4	137	518	2,067

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conv. Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2017	1,391	1,391	0	0	422	422	163	163	1,624	1,624
2018	122	827	0	0	72	453	18	158	152	1,060
2019	56	830	82	82	78	522	1	162	152	1,160

As of December 31, 2019, undeveloped reserves represented 13% per cent of total proved reserves and 16% per cent of proved plus probable reserves. Most of the undeveloped reserves are in our Swan Hills asset. There are 14 horizontal proved plus probable undeveloped Beaverhill Lake drilling locations in Swan Hills with an additional two vertical wells. There are two vertical wells in the Montney formation in Kaybob. There are five horizontal locations in Southern Alberta in the Gluaconitic and Mannville formations.

Reserves were assigned adhering to the practices outlined within the COGEH, with uncertainty applied at the individual location level to account for the potential variability in well results.

The pace of development of the proved and probable undeveloped reserves is scheduled to start in 2020 to 2022. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations or changing regulation and/or fiscal or environmental policy); (ii) program development may need to be spread over several years to optimize facility and pipeline utilizations; (iii) surface access issues (including weather conditions and regulatory approvals).

Other Oil and Gas Information

Principal Properties

Alberta

Swan Hills

The Swan Hills area is located in west central Alberta approximately 200 km northwest of Edmonton. As at December 31, 2019, the assets included 199,200 gross (164,476 net) acres of total land, of which 68,000 gross (63,831 net) acres were booked as undeveloped land. The assets at Swan Hills include 1,338 gross (744 net) wells in total, of which 306 gross (135 net) are producing wells. Production in the Swan Hills area is mainly from the legacy, large oil-in-place pools of the Swan Hills reef buildups of the Beaverhill Lake Group formation. Decline rates are predictable and low due to pressure support from existing waterflood schemes and further upside exists in optimization of existing floods, implementation of tertiary recovery schemes, reactivation of shut-in wells and drilling infill wells, both vertically and horizontally.

Oil and gas field production is gathered by flow lines to batteries and further transported by pipeline, and in certain limited areas by truck, to points of sale. Field-reported net working interest sales production from the area for the month ended December 31, 2019 averaged 3,226 boe/d comprised of 62% light oil, 23% NGL's and 15% natural gas.

Kaybob

The Kaybob area is located in west central Alberta approximately 250 km northwest of Edmonton. As at December 31, 2019, the assets included 89,440 gross (47,584 net) acres of total land, of which 19,120 gross (10,043 net) acres were booked as undeveloped land. The assets at Kaybob include 349 gross (204 net) wells in total, of which 76 gross (43 net) are producing wells. The majority of wells produce light oil from the Montney formation. Activity on operated lands is focused on the highly permeable coquina interval of the Montney formation, including infill drilling, waterflood optimization, reactivation of shut-in wells and implementation of further enhanced oil recovery schemes.

Oil and gas field production is gathered by flow lines to batteries and further transported by pipeline, and in certain limited areas by truck, to points of sale. Field-reported net working interest sales production from the area for the month ended December 31, 2019 averaged 936 boe/d of which 68% was light oil, 16% NGL's and 16% natural gas.

District South

The District South is an area located in Southern Alberta, approximately 250 km southeast of Calgary. As at December 31, 2019, the assets included 79,902 gross (50,456 net) acres of total land, of which 11,200 gross (5,387 net) were booked as undeveloped land. The assets include 509 gross (362 net) wells in total, of which 192 gross (109 net) are producing wells.

Production in District South is mainly from mature, well defined pools from the Lower Cretaceous era, consisting of both oil and gas deposits. Decline rates are low due to the mature nature of the pools. The oil pools have pressure support maintained through water injection, and the gas pools benefit from compression to maintain production. Upside exists in optimization of the existing water injection schemes, reactivation of shut in wells, and pipeline and facility consolidation and optimization of the gas infrastructure.

Oil production is mainly gathered to operated oil batteries for processing. The finished product is primarily transported by sales pipeline but in some areas is trucked out for sale. Gas production is gathered and compressed in Razor operated pipelines and facilities, and then processed at a 3rd party facility. Field reported net working interest sales production from the area for the ending December 31, 2019 was 225 boe/d, made up of 58% oil, 3% NGL's and 39% gas.

End of Life Expenditures

The Company's non-producing wells range in status from suspended through to reclaimed and awaiting a reclamation certificate. The Company allocates a portion of its annual budget to end of life expenditures in order to progress wells to the next stage in their life cycle.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company had a working interest as at December 31, 2019. All of the wells were located onshore in the province of Alberta.

	Producing				Non-Producing (3)					
	Oil		Gas		Oil		Gas		Other	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Operated	183	173	68	22	559	534	90	75	300	276
Non-operated	251	45	41	13	360	94	94	28	271	64
Total	**434**	**218**	**109**	**35**	**919**	**628**	**184**	**103**	**571**	**340**

Notes:
(1) "Gross" means total number of wells in which Razor holds an interest.
(2) "Net" means the aggregate of the percentage working interests of Razor in the gross wells.
(3) "Other" means all other active and inactive non-producing wells, such as injection wells.
(4) "Non-Producing" means wells that are not operated or may not have been previously on production and the date production will be obtained from these wells is uncertain. Abandoned wells are not included in the Table.

Razor has implemented an Inactive Well Management Program where all of its inactive wellbores are subject to a multidisciplinary review. This review establishes a plan for each wellbore, such as returning the well to production or injection, conducting end of life activities, or determining another use for the wellbore.

Properties with No Attributable Reserves

The following table summarizes the undeveloped land holdings (in acres) of the Company as at December 31, 2019.

	Undeveloped Acres		Developed Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	101,680	79,261	275,742	183,254	377,422	262,515
Total	**101,680**	**79,261**	**275,742**	**183,254**	**377,422**	**262,515**

Notes:
(1) "Gross" means the total number of acres in which Razor holds an interest.
(2) "Net" means the aggregate of the percentage working interests of Razor in the gross acres.

Razor expects that rights to explore, develop and exploit approximately 1440 net acres of undeveloped land holdings may expire by December 31, 2019. Razor closely monitors land expirations as compared to its development program with the strategy of minimizing undeveloped land expirations relating to significant identified opportunities. Razor does not anticipate any unusually high development, production or operating costs, any unusually high abandonment and reclamation costs, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations on properties with no contributed reserves. Other than commodity prices, there are no significant economic factors or significant uncertainties that affect the anticipated development or production activities on properties with no attributable reserves.

Forward Contracts and Marketing

From time to time, Razor enters into contracts to manage its exposure to fluctuations in commodity prices. A description of such contracts is provided in Note 14 of Razor's annual consolidated financial statements and accompanying Managements' Discussion and Analysis for the year ended December 31, 2019 and which can be found on SEDAR at www.sedar.com.

Tax Horizon

For the fiscal year end December 31, 2019, the Company paid no income tax and has approximately $84.8 million of tax pools available. Based on levels of production, commodity prices, acquisitions and capital expenditures, Razor does not expect to pay cash income taxes in the next five years.

Costs Incurred

The following table summarizes Razor's property acquisition costs, exploration costs and development costs for the year ended December 31, 2019.

Expenditure	**Year Ended December 31, 2019** ($000s)
Property acquisition costs	256
Development costs	13,590
Other	—
Total	**13,846**

Exploration and Development Activities

See "*Principal Properties*" above for a description of Razor's exploration and development activities.

Production Estimates

The following table sets forth the volume of Razor's gross working interest production estimated for the year ending December 31, 2019, as evaluated by Sproule, which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Information*".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	(BOE/d)
Proved					
Swan Hills	2,094	—	2,275	775	3,249
Kaybob	666	—	629	117	888
District South	198	119	1,198	17	534
Total Proved	**2,959**	**119**	**4,102**	**910**	**4,672**
Probable					
Swan Hills	55	—	48	16	78
Kaybob	8	—	11	2	12
District South	5	1	85	1	21
Total Probable	**68**	**1**	**144**	**18**	**110**
Total Proved plus Probable	**3,027**	**120**	**4,246**	**928**	**4,782**

Notes:
(1) Before deduction of royalties.
(2) Columns may not add due to rounding.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2019 Quarter Ended				Year Ended
	Q4	Q3	Q2	Q1	December 31
	Dec. 31	Sept. 30	June 30	March 31	2019
Average Daily Production[1]					
Light Oil (Bbls/d)	2,123	2,427	2,744	2,664	**2,488**
Heavy Oil (Bbls/d)	716	173	—	—	**224**
Natural gas liquids[2] (Bbls/d)	1,011	734	831	1,036	**903**
Conventional natural gas (Mcf/d)	4,962	6,206	3,414	3,929	**4,635**
Combined (BOE/d)	4,677	4,369	4,143	4,355	**4,387**
Average Daily Sales Volumes[1]					
Light Oil (Bbls/d)	2,146	2,425	2,932	2,741	**2,559**
Heavy Oil (Bbls/d)	716	173	—	—	**224**
Natural gas liquids[2] (Bbls/d)	1,011	734	831	1,036	**903**
Conventional natural gas (Mcf/d)	4,962	6,206	3,414	3,929	**4,635**
Combined (BOE/d)	4,700	4,367	4,332	4,432	**4,458**
Average Price Received					
Light Oil ($/Bbl)	66.37	66.23	73.47	65.26	**71.47**
Heavy Oil (Bbls/d)	35.32	35.58	—	—	**35.37**
Natural gas liquids ($/Bbl)	29.12	17.07	41.09	46.75	**30.94**
Conventional natural gas ($/Mcf)	1.69	1.01	1.06	2.56	**1.59**
Combined ($/BOE)	48.07	43.67	57.99	49.17	**49.66**
Royalties Paid[3]					
Light Oil ($/Bbl)	14.46	14.10	14.51	9.05	**12.96**
Heavy Oil (Bbls/d)	1.95	2.46	—	—	**2.05**
Natural gas liquids ($/Bbl)	5.35	6.58	8.41	17.71	**8.91**
Conventional natural gas ($/Mcf)	(4.01)	(9.09)	(5.53)	(3.13)	**(5.15)**
Combined ($/BOE)	10.80	8.07	8.81	7.01	**8.72**
Production Costs[3]					
Light Oil ($/Bbl)	31.17	31.60	36.84	36.01	**33.97**
Heavy Oil (Bbls/d)	38.37	20.40	—	—	**34.87**
Natural gas liquids ($/Bbl)	31.17	31.60	36.84	36.01	**33.97**
Conventional natural gas ($/Mcf)	5.19	5.27	6.14	6.00	**5.66**
Combined ($/BOE)	32.27	31.16	36.84	36.01	**34.02**
Netback Received[3][4]					
Light Oil ($/Bbl)	20.74	20.52	22.12	20.20	**24.53**
Heavy Oil (Bbls/d)	(5.00)	12.71	—	—	**(1.55)**
Natural gas liquids ($/Bbl)	(7.39)	(21.10)	(4.16)	(6.97)	**(11.94)**
Conventional natural gas ($/Mcf)	0.51	4.83	0.45	(0.31)	**1.07**
Combined ($/BOE)	5.00	4.44	12.34	6.15	**6.92**

Notes:
1) Before deduction of royalties. Production volumes are different than sales volumes in each quarter as the Company manages discretionary oil inventory builds in or draws in response to Light Sweet Edmonton Oil differentials compared to WTI.
2) Liquids include light and heavy oil and associated NGLs.
3) Razor did not record operating expenses on a commodity basis. Information in respect of operating expenses for oil ($/Bbl), natural gas liquids ($/Bbl) and natural gas ($/Mcf) has been determined by allocating expenses on a well by well basis based upon the relative volume of production of liquids and natural gas.
4) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. Information in respect of netbacks received for oil ($/Bbl), natural gas liquids ($/Bbl) and natural gas ($/Mcf) is calculated using operating expense figures for oil ($/Bbl), natural gas liquids ($/Bbl) and natural gas ($/Mcf), which figures have been estimated.

The following table indicates the average daily production volumes for the year ended December 31, 2019 for each of the important properties comprising Razor's assets:

	Light, Medium & Heavy Oil	Conventional Natural Gas	Natural Gas Liquids	
	(Bbls/d)	(Mcf/d)	(Bbls/d)	(BOE/d)
Swan Hills	2,022	2,742	741	3,226
Kaybob	631	944	147	936
District South	131	526	6	225
Total	2,784	4,213	894	4,387

The average production for the year ended December 31, 2019 was 84% liquids; and for the year ended December 31, 2019, 97% of gross revenue was derived from liquids production.

INDUSTRY CONDITIONS

Overview

Companies operating in the crude oil and natural gas industry are subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the crude oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of Razor Energy Corp. in a manner materially different than they would affect other oil and natural gas producers of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Some of the principal aspects of legislation, regulations and agreements governing the crude oil and natural gas industry are described further in the commentary below.

Razor Energy Corp. holds all of its current interests in crude oil and natural gas properties and related assets in Alberta. Our assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Company's upstream crude oil and natural gas business include a variety of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vi) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Recent Developments

To date in 2020, crude oil prices have declined dramatically, largely due to the actual and anticipated impact of the novel coronavirus ("COVID-19") outbreak upon global commerce and energy demand, and the recent disagreements between major oil producing nations with respect to production quotas. For more information, see "Risk Factors - Commodity Price Volatility" and "Risk Factors - Public Health Crises".

The OPEC production cuts in late 2019 and discussions of potentially further cuts in 2020 had, until recently, kept WTI oil prices in the mid-to-low US$50s per barrel. On March 9, 2020, oil prices fell precipitously due primarily to disagreements between the major oil producing nations of Saudi Arabia and Russia and growing concerns regarding the COVID-19 outbreak, creating substantial uncertainty and volatility in the global energy markets. Since then, WTI has continued to decline and on April 20, 2020 went negative for the first time in history but has since recovered to US$ 12-16 per barrel price range. In light of the current volatile environment, oil and gas producers may decrease their activities in general, both in the Canada and globally.

Until recently, overall global market conditions suggested that the industry would continue to maintain or increase production levels. Notwithstanding current uncertainties, Razor remains committed to responding to market fundamentals and is carefully monitoring emerging developments.

Availability of Services

Due to the economic downturn in Alberta during the past 5 years, the current COVID-19 pandemic and the high unemployment rate, the Company expects that there will be enough personnel and service companies available to carry out the Company's necessary and ongoing activity during the year 2020. Potential activities, but are not limited to, include reactivations, re-entries, optimizations, facilities, pipelines, end of life operations which will form a substantial portion of the Company's planned 2020 development. The Company will take necessary steps to adjust its annual program in the event external conditions arise that may constrain availability of personnel and service companies due to increased demand, competition or loss of potential personnel to COVID-19.

Land Tenure

Crude oil and natural gas rights located in the Western Canadian provinces are owned both by either the provincial governments (ie. the Crown) or by private individuals. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Rights are granted pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or to make certain payments. Where crude oil and natural gas is privately owned (ie. freehold mineral lands), the rights to explore for and produce such crude oil and natural gas are granted by the issuance of a lease on such terms and conditions as may be negotiated.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to the deep, non-productive geological formations at the conclusion of the primary term of a lease or licence.

Alberta also has a policy of “shallow rights reversion” which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. In April 2013, Alberta Energy placed an indefinite hold on serving shallow rights reversion notices for leases and licences that were granted prior to January 1, 2009. Alberta Energy stated that it will provide the industry with notice if, in the future, a decision is made to serve shallow rights reversion notices.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the Indian Act (Canada). Indian Oil and Gas Canada ("IOGC"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the Indian Oil and Gas Act (the "IOGA") and the Indian Oil and Gas Regulations, 1995 (the "1995 Regulations"). In 2009, Parliament passed An Act to Amend the Indian Oil and Gas Act, amending and modernizing the IOGA (the "Modernized IOGA"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the

"2019 Regulations"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. The Company has operations on Indian Oil & Gas Leases in the Jumpbush area of Alberta.

MARKET CONDITIONS

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with purchasers, with the result that the market determines the price of crude oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance, and contractual terms of sale.

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the National Energy Board Act (the "NEB Act") with the Canadian Energy Regulator Act (Canada) (the "CERA"), and replacing the National Energy Board (the "NEB") with the Canadian Energy Regulator ("CER"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGLs from Canada are subject to the CERA and remain subject to the National Energy Board Act Part VI (Oil and Gas) Regulation (the "Part VI Regulation"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("Cabinet") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Company does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Pipelines

Western Canada has seen significant growth in crude production volumes over recent years. This has resulted in pressure on the pipeline takeaway capacity, leading to apportionment on the main lines and, in turn, backed up local feeder pipelines. This has contributed to a widening of, and increased volatility in, the light oil pricing differential between West Texas Intermediate ("**WTI**") and Canadian Light Sweet Edmonton and the medium/heavy oil pricing differential between WTI and Cromer/WCS/ Hardisty/ Edmonton. Although pipeline expansions are ongoing and producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market production. In addition, the prorationing of capacity on the interprovincial systems also continues to affect the ability to export oil and natural gas.

Under the Canadian constitution, inter-provincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, including the United States, and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many pipeline projects or their cancellation altogether.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's Indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision quashing the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019 and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the Environmental Management Act (the "BC EMA") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal.

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("TC Energy") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. In April 2020, a Montana judge revoked a water-crossing permit required to complete construction of the pipeline. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada United States Border remains dependent on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the Oil Tanker Moratorium Act, which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tones to or from British Columbia's north coast.

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents and in February 2020, the Government of Alberta announced that it is finalizing the sale of the contracts.

Natural Gas

Natural gas prices in Alberta have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport for their natural gas production out of Western Canada, they may be able to access more markets and obtain better pricing. Companies without firm access to transportation in Western Canada may be forced to accept spot pricing for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States natural gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project. Pre-construction activities began in November 2018, with a planned completion target of 2025. In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("IA Agency").

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline 36 system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, as amended effective October 1 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbls/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for December 2019, January 2020 and February 2020 is set at 3.81 million bbls/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta. The Curtailment Rules are set to be repealed by December 31, 2020. The Company is not subject to a curtailment order.

Government Initiatives

On December 11, 2018, the Government of Alberta announced a Request for Expressions of Interest to create new refining capacity or expand existing capacity. The deadline for interested parties to submit Expressions of Interest was February 8, 2019, however, this Request for Expression of Interest was discontinued on October 23, 2019 as the Government of Alberta announced a $1.1 billion commitment to the Petrochemical Diversification Program which supports privately funded large-scale projects by providing royalty credits to companies that build facilities to turn ethane, methane and propane feedstocks into products such as plastics, fabrics and fertilizers.

GOVERNMENT REGULATIONS

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/USMCA

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed an authorization for a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "USMCA"), sometimes referred to as the Canada United States Mexico Agreement, or "CUSMA". On December 10, 2019, the three countries formally agreed to the USMCA. Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 and on March 13, 2020, the Canadian Parliament ratified the USMCA. In order for USMCA to enter into force the three signatory countries must align their internal laws and regulations with the provision's of the USMCA . The target date is June 1, 2020 but COVID-19 pandemic has disrupted the internal implementation process for all three of the USMCA parties and may cause a delay in the target date. Until then, NAFTA remains the North American trade agreement currently in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Company's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced. It is possible that the USMCA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

The Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), is a free trade agreement between Canada and 10 other countries in the Asia-Pacific region. The agreement which is intended to allow for preferential market access among the countries that are parties to the CPTPP. On December 30, 2018, the CPTPP came into force for the first six countries to ratify the agreement: Canada, Australia, Japan, Mexico, New Zealand, and Singapore. On January 14, 2019, the CPTPP came into force for Vietnam.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("CETA"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Extractive Sector Transparency Measures Act

The Extractive Sector Transparency Measures Act (“**ESTMA**”), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state-owned entities, including employees and public office holders, made by Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state-owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Failure to comply with the reporting obligations under ESTMA is punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $90 million in total liability.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids ("NGLs") and sulphur production. Royalties payable on production from minerals other than Crown owned minerals are determined by negotiations between the mineral owner and the lessee although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the provincial governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving near-term earnings and cash flow within the industry. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

In addition, the federal government may from time to time provide incentives to the oil and natural gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, aimed to provide oil and natural gas businesses with eligible Canadian development expenses ("CDE") and Canadian oil and gas property expenses ("COGPE") with a first year deduction of one and a half times the deduction that is otherwise available for CDE. The definitions of "accelerated CDE" and "accelerated COGPE", as amended in November 2018, allow oil and natural gas businesses to claim an additional 15% deduction for new CDE, and an additional 5% deduction for new COGPE for taxation years that end before 2024 if such CDE or COGPE was incurred after November 20, 2018. The acceleration is reduced to 7.5% for new CDE and 2.5% for new COGPE for taxation years that begin after 2023 and end before 2028. Successored expenses, and costs in respect of Canadian resource properties not acquired at arms' length, will not qualify for treatment as accelerated CDE or accelerated COGPE.

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totalling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program, a $200 per metre royalty credit was available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, subject to certain maximum amounts. The maximum credits available were determined by a company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2011. The new well incentive program applies to certain wells beginning production of conventional oil and natural gas after April 1, 2009 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum volume including all products of 7,949 cubic metres equivalent for oil wells and 14,100 cubic metres equivalent for gas wells.

On May 27, 2010, the Government of Alberta announced changes to the existing royalty framework under the Petroleum Royalty Regulation, 2009 and the Natural Gas Royalty Regulation, 2009 which became effective January 1, 2011 (the "**Alberta Royalty Framework**"). Changes include making the Natural Gas Deep Drilling Program, which adjusts the royalties for deep gas wells, a permanent initiative under the Alberta Royalty Framework. Qualifying wells under the Natural Gas Deep Drilling Program include natural gas wells with gas-oil ratios of greater than 1,800:1 which have been spud or deepened on or after May 1, 2010 and have a true vertical depth greater than 2,000 metres. An Emerging Resources and Technologies Initiative has also been created to encourage new exploration and development from higher cost and more technically challenging resources, such as shale gas, coal seams and horizontal oil and gas wells. In particular, pursuant to the Emerging Resource and Technologies Initiative: (a) coalbed methane wells will receive a maximum royalty rate of 5 percent for 36 producing months on up to 750 million cubic feet

("**Mmcf**") of production, retroactive to wells that began producing on or after May 1, 2010; (b) shale gas wells will receive a maximum royalty rate of 5 percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010; (c) horizontal gas wells will receive a maximum royalty rate of 5 percent for 18 producing months on up to 500 Mmcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and (d) horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

On January 29, 2016, the Alberta government announced changes to the Alberta Royalty Framework. Under the new modern royalty framework (the "**MRF**"), the sliding scale royalty concept will be maintained, but will be achieved with a greater degree of simplicity. The new royalty percentage will be applied to the gross revenue generated from all hydrocarbons, with no differentiation between produced substances, and wells will be charged a flat 5% royalty rate until revenues exceed a normalized well cost allowance, which will be based on vertical well depth and lateral length. The calculation of this cost allowance, and other details regarding the various parameters within the new formula under the MRF was announced in 2016 and was fully implemented as of January 1, 2017. Prior to January 1, 2017, the former royalty framework continued to apply to any wells drilled prior to that date, and thereafter for a period of 10 years following which, such wells will be transitioned into the MRF. Any changes to the royalty regime in Alberta may have a material effect on the Company. See "*Risk Factors*".

In addition to any negotiated royalty amount payable to the freehold mineral owner, producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the Freehold Mineral Rights Tax Act (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4 percent of revenues reported from fee simple mineral title properties.

Climate Change Regulation

Federal

In common with all producers, the Company's exploration activities and production facilities emit carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases" ("**GHG**").

Canada is a signatory to the United Nations Framework Convention on Climate Change ("**UNFCCC**"), which was entered into in order work towards stabilizing atmospheric concentrations of greenhouse gas ("**GHG**") emissions at a level to prevent "dangerous anthropogenic interference with the climate system". The UNFCCC came into force on March 21, 1994. On December 12, 2015, the UNFCCC adopted the Paris Agreement, which Canada ratified on October 5, 2016. Under the Paris Agreement, countries have also committed to an ambitious goal of holding the increase in global average temperature to well below 2°C above pre-industrial levels, while they pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. As of January 1, 2019, 184 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Katowice, Poland. The Conference concluded with the attendees reiterating their commitment to the targets set out in the Paris Agreement and establishing a transparency framework related to, among other matters, emissions and climate finance reporting.

In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC Secretariat, pledging a 30% reduction from 2005 levels - approximately 523 megatonnes - by 2030. In addition, provincial/territorial and federal leaders met and agreed that they would work together to build a national climate change plan. At a follow-up meeting of the First Ministers and Prime Minister on March 3, 2016, the parties agreed under the Vancouver Declaration on Clean Growth and Climate Change to launch a process to develop the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"), which was released on December 9, 2016 at the First Ministers meeting. Saskatchewan was the only province that decided not to adopt the Framework. Prior to the release of the Framework, the federal government announced in October 2016 that it will set a minimum price on carbon starting at $10 per tonne of CO2e in 2018, which will increase by $10 per year until it reaches $50 per tonne of CO2e by 2022. This approach will be reviewed in 2022 to confirm the path forward, including continued increases in stringency. Under the federal plan, each province and territory will be required to implement carbon pricing in its jurisdiction by 2018, whether in the form of a carbon tax or a cap-and-trade system. If the carbon price in a jurisdiction does not meet the federal minimum price, the federal government will step in and impose a carbon price that makes up the difference and return the revenue to the province or territory. In addition, provincial and territorial goals for reducing emissions must be at least as stringent as federal targets. Seven provinces and territories have introduced carbon-pricing systems in place that would meet federal requirements (Alberta, British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador and the Northwest Territories). The federal carbon-pricing regime will take effect in Saskatchewan, Manitoba, Ontario and New Brunswick in April 2019; it will take effect in the Yukon and Nunavut in July 2019. Saskatchewan and Ontario have challenged the constitutionality of the federal government's pricing regime and New Brunswick has intervened in Saskatchewan's constitutional challenge. In October 2018, the federal government announced an alternative pricing scheme for large electricity generators designed to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation rates.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, but will not come into force until January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 Mt by 2030.

In March 2016, a Joint Statement on Climate, Energy, and Arctic Leadership was issued. This joint statement sets out specific commitments on energy development, environmental protection, and Arctic leadership. In particular, Canada and the US have made commitments to reduce methane emissions by 40-45 percent below 2012 levels by 2025 from the oil and gas sector, finalize and implement the second phase of an aligned GHG emission standard for post-2018 model year on-road heavy duty vehicles, phase out fossil fuel subsidies, accelerate clean energy development and foster sustainable energy development.

In December 2017, Environment and Climate Change Canada ("**ECCC**") published its updated requirements and step-by-step reporting instructions in advance of the 2017 reporting period under the federal Greenhouse Gas Reporting Program (**"GHGRP"**). The Notice with respect to reporting of greenhouse gases for 2017, which was published on December 30, 2017 in Part I of the Canada Gazette, outlines the 2017 reporting requirements for GHG-emitting facilities. In December 2017, ECCC published its updated requirements and step-by- step reporting instructions in advance of the 2017 reporting period under the GHGRP. Starting in the 2017 reporting year, the GHGRP will apply to a wider range of GHG emitting operations in Canada, as the reporting threshold was lowered from 50,000 tonnes to 10,000 tonnes of CO2e. All facilities that emitted the equivalent of 10,000 tonnes of CO2e in 2017 were required to submit a report by June 1, 2018.

In November 2016, the federal government announced that it would commence development of a performance-based clean fuel standard ("**CFS**") that would incent the use of a broad range of low carbon fuels, energy sources and technologies. The objective of the CFS is to achieve 30 Mt of annual reductions in GHG emissions by 2030, as part of efforts to achieve Canada's commitments under the Paris Agreement. On December 13, 2017, ECCC published a regulatory framework on the CFS, which outlines the key design elements for the CFS regulation, including its scope, regulated parties, carbon intensity approach, timing, and potential compliance options such as credit trading. The proposed regulations to implement CFS are not anticipated to be enacted until mid-2019.

In March 2016, a Joint Statement on Climate, Energy, and Arctic Leadership was issued. This joint statement sets out specific commitments on energy development, environmental protection, and Arctic leadership. In particular, Canada and the US have made commitments to reduce methane emissions by 40-45% below 2012 levels by 2025 from the oil and gas sector, finalize and implement the second phase of an aligned GHG emission standard for post-2018 model year on-road heavy duty vehicles, phase out fossil fuel subsidies, accelerate clean energy development and foster sustainable energy development.

It is expected that additional regulations eventually implemented by the Government of Canada will have an impact on the oil and gas industry as a whole, which could result in increased costs for the Company to comply with such legislation. There remains ongoing uncertainty regarding Canada's short-term and long-term emissions reduction targets and how such targets will be achieved. In the meantime, the Company will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions.

Alberta

On July 1, 2007, the Specified Gas Emitters Regulation ("**SGER**") came into force under Alberta's Climate Change and Emissions Management Amendment Act requiring Alberta facilities which emit more than 100,000 tonnes of GHGs annually ("**Regulated Emitters**") to reduce their GHG emissions intensity by 12% (from average 2003-2005 levels).

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership Report, the Government of Alberta announced its Climate Leadership Plan which introduced a carbon tax on all emitters beginning January 1, 2017 at $20 per tonne of GHG emissions, increasing to $30 per tonne in January 2018. An oil sands specific approach was also introduced to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was introduced for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation, in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Carbon pricing was also identified by the Climate Advisory Panel as the primary policy tool for reducing emissions in the province. On June 23, 2016, the Alberta legislature passed the Climate Leadership Implementation Act (Bill 20) which furthers the implementation of the Climate Leadership Plan. Details of Alberta's carbon pricing model were detailed in its April 2016 budget, which earmarks almost $8.5 billion to build and modernize major public infrastructure. Budget 2016 also allocates $634 million to various climate change initiatives in addition to funds for roads and bridges, flood recovery and municipal infrastructure support. The Act came into force on January 1, 2017 and empowers the provincial government to impose a carbon levy in the province. As of January 1, 2017, a $20 per tonne carbon levy will be applied to fuels that emit GHG when combusted. This levy increased to $30 per tonne in 2018. Fuels covered by the levy include transportation and heating fuels such as diesel, gasoline, natural gas and propane. It will not apply directly to consumer purchases of electricity. Revenues from the carbon levy will be used for initiatives to reduce GHG emissions and to fund carbon rebates, as well as for investments in clean technology and green infrastructure. The carbon levy will also be used for an "adjustment fund" to help individuals and families, small business and First Nations adjust. While the levy is anticipated to increase again in 2021, in line with the federal legislation, the Government of Alberta has announced that it will not proceed with the 2021 increase unless the expansion to the Trans Mountain Pipeline proceeds.

On January 1, 2018, the Carbon Competitiveness Incentive Regulation ("**CCI Regulation**") replaced the SGER. Under the CCI Regulation, facilities are allowed to emit a certain amount of GHG, free of charge from the carbon levy. This approach is designed to protect industries from competitiveness impacts that could shift production to other jurisdictions. The CCI Regulation applies to facilities that emitted 100,000 tonnes or more of GHG in 2003, or a subsequent year. A facility with less than 100,000 tonnes of GHG may be eligible to opt-in to the CCI Regulation if it competes against a facility regulated under the CCI or has more than 50,000 tonnes of annual emissions, high emissions-intensity and trade-exposure (by opting in, facilities become exempt from the application of the carbon levy for fuels whose emissions are included in their site reporting). Under the updated system, a facility will receive performance credits if its GHG emissions are less than the amount freely permitted. If its emissions are above the amount freely permitted, they will be required take one or more of the following actions to bring the facility into compliance:

- make improvements at their facility to reduce emissions intensity;
- use emission performance credits generated at facilities that achieve more than the required reductions;
- purchase Alberta-based carbon offset credits; or
- contribute to Alberta's Climate Change and Emissions Management Fund.

Emissions from the oil sands sector (which account for approximately one-quarter of Alberta's annual emissions) have been capped at 100 Mt per year. This cap has been legislated in the Oil Sands Emissions Limit Act (Bill 25), which was introduced in November 2016. The legislation contemplates certain exceptions in respect of cogeneration emissions, upgrading emissions, and potential discretionary exemptions by regulation (likely to accommodate new technological developments). Bill 25 came into force on December 14, 2016.

In January 2018, the Alberta government also announced that it is adopting ECCC's greenhouse gas reporting requirements for the 2017 reporting period, meaning that facilities emitting 10,000 tonnes of CO2e or more must submit a specified gas report to Alberta Climate Change Office via ECCC's SWIM reporting system (the reporting threshold for previous years is 50,000 tonnes of CO2e). Facilities were required to report their 2017 greenhouse gas emissions to ECCC's SWIM system by June 1, 2018.

On October 29, 2019, the Government of Alberta announced Bill 19 to replace the CCI Regulation with the Technology Innovation and Emissions Reduction ("TIER"). Under TIER, thresholds for large facilities and compliance mechanisms remain largely the same as under the CCI Regulation. However, under TIER, a facility will be measured either against its own average emissions from prior years and its target will be set at ten percent below that level for 2020, or using an industry specific benchmark set by regulation. If a facility is over its target, the price will be $30.00 per tonne CO2e.

Beginning on May 30, 2019 as part of the Carbon Tax Repeal Act, the carbon levy no longer applies to any type of fuel; however, as Alberta has no carbon levy equivalent for fuel consumption, the federal government announced that beginning on January 1, 2020 a federal fuel charge will apply in Alberta.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions. In addition to the royalties payable to the mineral owners, (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces. Where oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Environmental Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to evolving national, provincial and municipal laws and regulations, as well as, potentially, international conventions. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced in association with oil and gas operations, habitat protection and minimum setbacks of oil and gas activities from fresh water bodies. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines, penalties and sanctions, some of which may be material or materially affect the Company's operations. Certain environmental protection legislation may subject the Company to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge. Further, as Canadian environmental legislation evolves, the use of administrative penalties by the imposition of fines for the commission of environmental offences on an absolute liability basis has grown.

Environmental legislation is evolving in a manner that has and is expected to continue to result in stricter standards and enforcement, larger fines, liabilities and sanctions, and potentially increased capital expenditures and operating costs. To mitigate potential environmental liabilities, the Company, in addition to implementing policies and procedures designed to prevent an accidental spill or discharge, maintains insurance at industry standards.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport.

On August 28, 2019, the Government of Canada passed Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("**CER**"). Pursuant to Bill C-69, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. Additional categories of projects may be included within new impact assessment process, such as largescale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on:

(i) early engagement by proponents to engage the Agency and all stakeholders, such as the public and indigenous groups, prior to the formal impact assessment process;

(ii) potentially increased public participation where the project undergoes a panel review;(iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public- interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government;

(iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and

(v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities.

Many of the CER's activities would be similar to the NEB, but with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The effects of the proposed regulatory scheme remains unclear.

On May 12, 2017, the federal government introduced Bill C-48, the Oil Tanker Moratorium Act in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the Oil Tanker Moratorium Act which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53?00??north latitude and west of 126°38?36??west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

Alberta

The discharge of oil, natural gas, or other pollutants into the air, soil or water may give rise to liabilities to third parties and may require the Company to incur costs to remedy such discharge in the event that they are not covered by the Company's insurance. Although the Company maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. Environmental legislation in the Province of Alberta is, for the most part, set out in the Environmental Protection and Enhancement Act ("EPEA"), the Water Act and the Oil and Gas Conservation Act ("OGCA"). The EPEA and the OGCA impose strict environmental standards with respect to releases of effluents and emissions, require stringent compliance, reporting and monitoring obligations, and impose significant penalties for non-compliance.

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the OGCA. On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Parks ("**AEP**") in respect of the disposition and management of public lands under the Public Lands Act. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AEP in the areas of environment and water under EPEA and the Water Act, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The oil and gas industry is subject to such environmental regulations which include restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

The Company believes it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. The Company's practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. The Company also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation.

No assurance can be given that environmental laws will not result in a curtailment of production, a material increase in the costs of production or the costs of development or exploration activities, or otherwise adversely affect the Company's financial condition, capital expenditures, results of operations, competitive position or prospects.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**LLR Program**") as part of the Liability Management Rating Assessment Process. The LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The OGCA establishes an orphan well fund (the "**Orphan Well Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Well Fund is funded by licensees in the LLR Program through a levy administered by the AER. The LLR Program is designed to minimize the risk to the Orphan Well Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and upon the submission of a license transfer application, and failure to post the required security deposit may result in the initiation of enforcement actions by the AER.

On May 1, 2013, the AER began to implement a three year program of changes to the LLR Program. Some of the important changes which were implemented through this three year process include: (a) increases to the prescribed average reclamation cost for each individual well or facility (which increased a licensee's deemed liabilities); (b) increases to facility abandonment cost parameters for each well equivalent (which increased a licensee's deemed liabilities); (c) use of an industry netback averaged over the last three years (which affected the calculation of a licensee's deemed assets); and (d) a change to the present value and salvage factor, which increases to 1.0 for all active facilities from 0.75 for active wells and 0.50 for active facilities (which increased a licensee's deemed liabilities).

The changes were implemented over a three-year period, ending August 2015. The first phase was implemented in May 2013, the second phase was implemented in May 2014 and the final phase was implemented in August 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in Redwater Energy Corporation (Re) ("Redwater"), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years.

All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

The AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: Suspension Requirements for Wells ("Directive 013"). The IWCP applies to all inactive wells that are noncompliant with Directive 013. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20 percent of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76 percent of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("ABC") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list, and should not be taken as a complete summary or description of all the risks associated with the Company's business and the oil and natural gas business generally.

Overview

The Company's business consists of the exploration and production of crude oil and natural gas projects, with producing properties in the province of Alberta. There are a number of inherent risks associated with the exploration and production of oil and gas reserves. Many of these risks are beyond the control of the Company.

Nature of Business

An investment in the Company should be considered highly speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, production and marketing of, oil and natural gas reserves and its current stage of development. Oil and gas operations involve many risks which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Difficulty Implementing Business Strategy

The growth and expansion of the Corporation is heavily dependent upon the successful implementation of its business strategy. There can be no assurance that the Corporation will be successful in the implementation of its business strategy.

Commodity Price Volatility

Razor's results of operations and financial condition are dependent on the prevailing prices of crude oil and natural gas. Crude oil and natural gas prices have fluctuated widely in the recent past and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond Razor's control. Crude oil and natural gas prices are impacted by a number of factors including, but not limited to: the global supply of and demand for crude oil and natural gas; global economic conditions; the actions of the Organization of Petroleum Exporting Countries ("**OPEC**") and OPEC +; government regulation; political stability and geopolitical factors; the ability to transport crude to markets; developments related to the market for liquefied natural gas; the availability and prices of alternate fuel sources; and weather conditions. Recently, global oil prices have weakened materially as a result of the COVID-19 pandemic, compounded by OPEC+, led by Saudi Arabia and Russia, failing to reach an agreement on constraining output. Concerns over global economic conditions, fluctuations in interest rates and foreign exchange rates, stock market volatility, energy costs, geopolitical issues, OPEC + actions, inflation, the availability and cost of credit, the deceleration of economic growth in the People's Republic of China, trade disputes between the United States and the People's Republic of China, civil unrest in Venezuela and Iran and the outbreak of COVID-19 have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, significant growth in crude production volumes in Western Canada and the northern United States has resulted in pressure on transportation and pipeline capacity, contributing to the widening of the light oil pricing differential between WTI and Cromer/Hardisty/ Edmonton, resulting in fluctuations in the price of oil and natural gas. Oil and natural gas producers in Western Canada may receive significantly discounted prices for some of their production due to regional constraints on their ability to transport and sell such production. All of these factors are beyond Razor's control and can result in a high degree of price volatility.

Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in United States dollars, are stated in Canadian dollars. Razor's financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between the Company's light oil (in particular the light differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions; refining demand; and the quality of the oil produced, all of which are beyond Razor's control. See also "*Variations in Foreign Exchange Rates and Interest Rates*".

Fluctuations in the price of commodities and associated price differentials may impact the value of Razor's assets and the ability to maintain its business and to fund growth projects. Prolonged periods of commodity price depression and volatility may also negatively impact Razor's ability to meet guidance targets and meet all of its financial obligations as they come due. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations, prospects and the level of expenditures for the development of oil and natural gas reserves, including delay or cancellation of existing or future drilling or development programs or curtailment in production.

Any material or sustained decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Company's reserves. Razor might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities.

Crude oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies and OPEC actions. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid.

Razor conducts regular assessments of the carrying value of its assets in accordance with IFRS. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of the Company's assets may be subject to impairment.

Ability to Continue as a Going Concern

As at December 31, 2019, the Company had a working capital deficit of $19.5million, of which only $1.9 million is comprised of cash and cash equivalents. Further, at December 31, 2019, the Company has contractual repayments of $37.2 million due in less than one year. In addition, the Company is projecting covenant violations with respect to the adjusted net debt-to-adjusted EBITDA cash flow ratio and the minimum working capital ratio on the Amended Term Loan Facility with AIMCo at the next annual compliance date of December 31, 2020, which in any regard matures and requires repayment of $45.0 million on January 31, 2021.

The Company anticipates funding the working capital deficit and contractual repayments with a combination of cash from operations and potential new debt financing, which will also be necessary to address the upcoming maturity of the Amended Term Loan Facility. However, the operational challenges that impacted production and operating costs along with a volatile economic environment due to severe negative global commodity price pressures and COVID-19 implications continues to negatively impact current and forecasted operating cash flows. The Company is currently projecting to use cash flow in operations due to low commodity prices and the shut-in of production, and as such a material uncertainty remains as to whether the Company can generate sufficient positive cash flow from operations to meet all of its obligations as they come due. In addition, no assurance can be provided that the Company will be able to obtain new debt financing to bridge any working capital or contractual repayment shortfall or to replace the Amended Term Credit Facility. The Company will also seek to obtain relief from the projected covenant violations, however in light of current economic conditions there is no certainty that relief will be obtained.

Due to the conditions noted above there remains a material uncertainty surrounding the Company’s ability to generate adequate cash flow from operations or to obtain new financing to fund the working capital deficit, contractual payments and maturity of the Amended Term Credit Facility. These material uncertainties create significant doubt with respect to the Company’s ability to meet its obligations as they come due and, therefore, it may be unable to realize its assets and discharge its liabilities in the normal course of business.

Our audited consolidated financial statements for the year ended December 31, 2019 have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business. Our audited consolidated financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for our audited consolidated financial statements, then adjustments would be necessary in the carrying value of the assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

Public Health Crises

Razor’s business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China. On January 30, 2020, the World Health Organization declared the outbreak a global health emergency and on March 11, 2020, the World Health Organization declared the outbreak a pandemic. In China, reactions to the spread of COVID-19 have led to, among other things, significant restrictions on travel within China, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread throughout Europe, the Middle East, Canada and the United States, causing companies and various international jurisdictions to impose restrictions such as quarantines, business closures, restrictions on public gatherings and travel restrictions. While these effects are expected to be temporary, the duration of the business disruptions internationally and related financial impact cannot be reasonably estimated at this time. Similarly, Razor cannot estimate whether, or to what extent, this outbreak and the potential financial impact may extend to countries outside of those currently impacted.

Such public health crises can result in volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, oil prices have significantly weakened in response to the outbreak of COVID-19. See “Commodity Price Volatility”, above. The risks to Razor of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations impacted by an outbreak. At this point, the extent to which COVID-19 may impact Razor is uncertain; however, it is possible that COVID-19 may have a material adverse effect on the Razor's business, results of operations and financial condition.

Gathering and Processing Facilities, Pipeline Systems and Rail

The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the inability to realize the full economic potential of the Company's production or in a reduction of the price offered for its production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Company's business and, in turn, its financial condition, operations and cash flows. Announcements and actions taken by the government of Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced Bill C-69 to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

Capital Lending Markets

As a result of recent economic uncertainties in the oil and gas industry and, in particular, the lack of risk capital available to the junior resource sector, the Company, along with other junior resource entities, may have reduced access to bank debt and to equity. As future capital expenditures will be financed out of funds generated from operations, bank borrowings, if available, and possible issuances of debt or equity securities, the Company's ability to fund future capital expenditures is dependent on, among other factors, the overall state of lending and capital markets and investor and lender appetite for investments in the energy industry, generally, and the Company's securities in particular.

To the extent that external sources of capital become limited, unavailable or available only on onerous terms, the Company's ability to invest and to maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Markets and Marketing

The marketability and price of crude oil and natural gas that may be acquired or discovered by the Company is, and will continue to be, affected by numerous factors beyond its control. Razor's ability to market its crude oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Razor may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and gas business.

Exploration and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on exploration by the Company will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The Company currently has a limited number of specific identified exploration or development prospects. Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and their past practices. The long term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and

natural gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.
Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow outs, cratering, sour gas releases, fires, spills or leaks. These risks could result in personal injury, loss of life, and environmental or property damage. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial conditions.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC+, the COVID-19 pandemic, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by governments at the federal and provincial levels. In addition, the inability to get the necessary approvals to build pipelines, LNG plants and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Company's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, the Company's cash flow resulting in a reduced capital expenditure budget. Consequently, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis.

Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, our cash flow may not be sufficient to continue to fund our operations and satisfy our obligations when due, and our ability to continue as a going concern and discharge our obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to us or at all. Similarly, there can be no assurance that we will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge our obligations and continue as a going concern.

Legal Proceedings

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on the Company's assets, liabilities, business, financial condition and results of operations.

The Company is named as a defendant in the Action. See "*Legal Proceedings and Regulatory Actions*". While management of the Company does not believe that this action will have a material effect on the business or financial condition of the Company, no assurance can be given as to the final outcome of this or any other legal proceedings or that the ultimate resolution of this or any other legal proceedings will not have a material adverse effect on the Company.

In the event that the Action would be determined in a manner adverse to the Company, it could have a material adverse effect on the Company's business, financial condition and results of operations. Although the Company is of the view that an injunction is unlikely to be granted to prohibit the acquisition of the assets described in the Action, no assurance can be given to that effect.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the U.S. has withdrawn from the CPTPP and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on December 10, 2019, and Canada, the U.S. and Mexico signed the USMCA, which has subsequently been ratified by the three signatory countries. See "Industry Conditions - The North American Free Trade Agreement and Other Trade Agreements". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is presently unclear how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including Razor.

In addition to the political disruption in the United States, the citizens of the United Kingdom have voted to withdraw from the European Union and the Government of the United Kingdom implemented such withdrawal on January 31, 2020. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on Razor's ability to market products internationally, increase costs for goods and services required for operations, reduce access to skilled labour and negatively impact business, operations, financial conditions and the market value of the Common Shares.

Fiscal and Royalty Regimes

In addition to federal regulation, each province has legislation and regulations which govern land tenure, drilling and construction permits, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on well productivity, geographical location, field discovery data and the type or quality of the petroleum product produced. See "*Industry Conditions*".

The royalty regime in Alberta, and any other jurisdictions in which the Company's oil and natural gas assets are located, may be subject to further review and changes which could adversely impact the Company's financial condition and operations. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic.

Changes in Legislation

It is possible that the Canadian federal and provincial government or regulatory authorities could choose to change the Canadian federal income tax laws, royalty regimes, liability management, environmental and climate change laws or other laws applicable to oil and gas companies and that any such changes could materially adversely affect the Company, its shareholders and the market value of the Common Shares.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time.

Insurance

Razor's involvement in the exploration for and development of oil and gas properties may result in Razor becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although Razor will obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Razor may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to Razor. The occurrence of a significant event that Razor is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Razor’s financial position, results of operations or prospects.

Project Risks

The Company will manage and participate in a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Project cost estimates may not be accurate due to a lack of history of comparable projects. Furthermore, significant project cost over-runs could make a project uneconomic.

The Company’s ability to execute projects and market oil and natural gas will depend upon numerous factors beyond the Company’s control, including: the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of storage capacity; the supply of and demand for oil and natural gas; the availability of alternative fuel sources; the effects of inclement weather; the availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; changes in regulations; the availability and productivity of skilled labour; and the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Substantial Capital Requirements and Liquidity

Razor anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Razor’s future revenues or reserves decline, Razor may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash flow from operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Razor. Moreover, future activities may require Razor to alter its capitalization significantly. The inability of Razor to access sufficient capital for its operations could have material adverse effect on Razor’s financial condition, results of operations or prospects.

Competition

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

The oil and gas industry is highly competitive. Razor’s competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities include companies that have greater financial and personnel resources available to them than Razor.

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

Cost of New Technologies

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. The Company's actual interest in properties may vary from its records. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Company controls that, if successful or made into law, could impair the Company's activities on them and result in a reduction of the revenue received by the Company.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. No assurance can be given that the application of environmental laws to the business and operations of the Company will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids resources, reserves and cash flows to be derived therefrom, including many factors beyond the Company's control. In estimating reserves, the chance of commerciality is effectively 100%. For prospective resources, the chance of commerciality will be the product of the chance that a project will result in a discovery of petroleum or natural gas and the chance that an accumulation will be commercially developed. 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 resources.

The reserve and associated cash flow information and estimates represent estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material. Actual future net revenue from the Company's assets will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and revenues derived therefrom will vary from the estimates, and such variations could be material.

There are numerous uncertainties inherent in estimating quantities of resources, including many factors beyond the Company's control, and no assurance can be given that the indicated level of resources will be realized. In general, estimates of recoverable resources are based upon a number of factors and assumptions made as of the date on which the resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable natural gas and the classification of such resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

Geological risking of prospective resources addresses the probability of success for the discovery of petroleum; this risk analysis is conducted independently of probabilistic estimates of petroleum volumes and without regard to the chance of development. Principal risk elements of the petroleum system include: (i) trap and seal characteristics; (ii) reservoir presence and quality; (iii) source rock capacity, quality and maturity; and (iv) timing, migration and preservation of petroleum in relation to trap and seal formation. Geological risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators.

Estimates with respect to resources that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of resources, rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same resources based upon production history will result in variations, which may be material, in the estimated resources.
Prospective resources are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources.

Resources estimates may require revision based on actual production experience. Market price fluctuations of natural gas prices may render uneconomic the recovery of the resources.

Liability Management

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Company's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that the Company must post.

As a result of the Supreme Court of Canada's January 2019 decision in the Redwater case, a trustee in bankruptcy is not permitted to renounce uneconomic oil and gas assets and leave these assets to be remediated by the Orphan Well Fund, thereby avoiding the environmental liabilities of the estate it is administering. Accordingly, the AER may now use Alberta's provincial legislative scheme to prevent the repudiation or renunciation of an insolvent company's assets by a trustee and require the trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors. In response to the Supreme Court's decision, the AER is also working on an improved liability management framework. Razor cannot predict what the AER's improved framework may look like but such pending changes to the AB LLR Program will have an impact on crude oil and natural gas production in Alberta, including Razor's business.

The AER's new liability management framework may impact the Company's ability to transfer its licences, approvals or permits in the course of a divestment, and may result in increased costs and delays or require changes to or abandonment of projects and transactions. As a result of the decision in Redwater, lenders may reduce the availability of credit to oil and gas issuers that utilize secured loans, thereby negatively affecting the financial capacity of such issuers, including potential partners and counterparties of the Company. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Company, and the associated A&R liabilities in determining whether to provide credit, may require borrowers to adhere to more stringent A&R-related operational covenants, and may increase the cost of providing credit.

The Supreme Court decision in Redwater also could make the transfer of oil and gas assets from insolvent parties more challenging if a trustee in bankruptcy is unable to separate economic assets from uneconomic assets within the insolvent party's estate in order to facilitate a sale process. The result could be additional liabilities being placed upon the Orphan Well Fund. The Orphan Well Fund may seek funding for such liabilities from industry participants, including the Company, through an increase in its annual levy, further changes to regulations, or other means. While the impact on the Company of any legislative, regulatory or policy decisions as a result of the Redwater decision cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact the Company and materially and adversely affect, among other things, the Company’s business, financial condition, results of operations and cash flow.

There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See “*Industry Conditions*”.

Income Taxes

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Company. Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company 's detriment.

Climate Change

Razor’s exploration and production facilities and other operations and activities emit GHGs and which may require Razor to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. Public support for climate change action and receptivity to new technologies has grown in recent years. Governments in Canada and around the world have responded to these shifting societal attitudes by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. There has also been increased activism, including threats of culpability, legal action against oil and gas producers, and public opposition to fossil fuels and the oil and gas industry in which the Company operates. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on Razor and its operations and financial condition. See *“Industry Conditions”*.

Reserve Replacement

Razor’s future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Razor successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Razor may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Razor’s reserves will depend not only on Razor’s ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Razor’s future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes acquisitions and dispositions of businesses and assets that occur in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as realizing the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources and may divert management’s focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of individual properties and other assets. In this regard, non-core assets are periodically disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could realize less than their carrying amount on the financial statements of the Company.

Finding, Developing and Acquiring Petroleum and Natural Gas Reserves on an Economic Basis

Petroleum and natural gas reserves naturally deplete as they are produced over time. The success of the Company's business is highly dependent on its ability to acquire and/or discover new reserves in a cost efficient manner. Substantially all of the Company's cash flow is derived from the sale of the petroleum and natural gas reserves it accumulates and develops. In order to remain financially viable, the Company must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis. The reserves and costs used in this determination are estimated each year based on numerous assumptions and these estimates and costs may vary materially from the actual reserves produced or from the costs required to produce those reserves. The Company mitigates this risk by employing a qualified and experienced team of petroleum and natural gas professionals, operating in geological areas in which prospects are well understood by management and by closely monitoring the capital expenditures made for the purposes of increasing its petroleum and natural gas reserves.

Operational Dependence

Other companies operate some of the assets in which Razor has an interest. As a result, Razor will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Razor's financial performance. Razor's return on assets operated by others will therefore depend upon a number of factors that may be outside of Razor's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Reliance on Key Personnel

Razor's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on Razor's business, financial condition, results of operations and prospects. Razor does not have any key person insurance in effect. The contributions of the existing management team to Razor's immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Razor will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of Razor's management.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licences and Leases

The Company's properties are held in the form of licences and leases and working interests in licences and leases. If the Company or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Company's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Company's results of operations and business.

Permits and Licences

The operations of Razor may require licences and permits from various governmental authorities. There can be no assurance that Razor will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its properties.

Additional Funding Requirements

Razor's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Razor may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Razor to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Razor's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Razor's ability to expend the necessary capital to replace its reserves or to maintain its production. If Razor's cash flow from operations and current cash balance is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favorable terms.

Dividends

On February 5, 2020, the Company suspended the payment of dividends effective February 2020 in response to significant price volatility for crude products in the Canadian energy sector. The amount of future cash dividends paid by the Company, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends.

Additional Taxation Applicable to Dividends Paid to Non-Residents

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. Where a non-resident is a United States resident entitled to benefits of the Canada - United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rate, which will fluctuate over time. Future Canadian/United States exchange rates could accordingly impact the future value of Razor's reserves as determined by independent evaluators. Furthermore, an increase in interest rates could result in a significant increase in the amount the Company pays to service debt.

Issuance of Debt

From time to time, Razor may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may increase Razor's debt levels above industry standards. Neither Razor's articles of incorporation nor its by-laws limit the amount of indebtedness that Razor may incur. The level of Razor's indebtedness from time to time could impair Razor's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Razor's ability to meet its debt service obligations will depend on Razor's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Razor. As certain of the indebtedness of Razor would bear interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Razor's interest payment obligations and could have a material adverse effect on Razor's financial condition and results of operations. Further, Razor's indebtedness would be secured by substantially all of Razor's assets. In the event of a violation by Razor of any of its loan covenants or any other default by Razor on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on Razor's assets. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Hedging

From time to time, the Company uses financial instruments and physical delivery agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company may not benefit from such increases. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from its fluctuating exchange rate.

Availability of Drilling Equipment and Access Restrictions

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Razor and may delay exploration and development activities.

Information Technology Systems and Cyber-Security

Razor has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure, to conduct daily operations. Razor depends on various information technology systems to estimate reserve quantities, process and record financial data, manage the land base, analyze seismic information, administer contracts with operators and lessees and communicate with employees and third-party partners.

Further, Razor is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of its information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to Razor's business activities or competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on Razor's performance and earnings, as well as on Razor's reputation. Razor has technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on Razor's business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of Western Canada. The Company is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of this Company. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Conflicts of Interest

Directors and officers of Razor may also be directors and officers of other oil and gas companies involved in oil and gas exploration and development, and conflicts of interest may arise between their duties as officers and directors of Razor and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the ABCA.

Dilution

Razor may make future acquisitions or enter into financings or other transactions involving the issuance of its securities which may be dilutive.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Company's exploration and development activities, which could in turn have a material adverse impact on the Company's business, operations and prospects.

Third Party Credit Risk

The Company is, or may be, exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Liability Management

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Company's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that the Company must post.

As a result of the Supreme Court of Canada's January 2019 decision in the Redwater case, a trustee in bankruptcy is not permitted to renounce uneconomic oil and gas assets and leave these assets to be remediated by the Orphan Well Fund, thereby avoiding the environmental liabilities of the estate it is administering. Accordingly, the AER may now use Alberta's provincial legislative scheme to prevent the repudiation or renunciation of an insolvent company's assets by a trustee and require the trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors. In response to the Supreme Court's decision, the AER is also working on an improved liability management framework. Razor cannot predict what the AER's improved framework may look like but such pending changes to the Alberta LLR Program will have an impact on crude oil and natural gas production in Alberta, including Razor's business.

The AER's new liability management framework may impact the Company's ability to transfer its licences, approvals or permits in the course of a divestment, and may result in increased costs and delays or require changes to or abandonment of projects and transactions. As a result of the decision in Redwater, lenders may reduce the availability of credit to oil and gas issuers that utilize secured loans, thereby negatively affecting the financial capacity of such issuers, including potential partners and counterparties of the Company. Lenders also may generally increase their scrutiny of oil and gas assets held by producers, including the Company, and the associated abandonment and reclamation liabilities in determining whether to provide credit, may require borrowers to adhere to more stringent abandonment and reclamation-related operational covenants, and may increase the cost of providing credit.

The Supreme Court decision in Redwater also could make the transfer of oil and gas assets from insolvent parties more challenging if a trustee in bankruptcy is unable to separate economic assets from uneconomic assets within the insolvent party's estate in order to facilitate a sale process. The result could be additional liabilities being placed upon the Orphan Well Fund. The Orphan Well Fund may seek funding for such liabilities from industry participants, including the Company, through an increase in its annual levy, further changes to regulations, or other means. While the impact on the Company of legislative, regulatory or policy decisions as a result the Redwater decision cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact the Company and materially and adversely affect, among other things, the Company's business, financial condition, results of operations and cash flow.

There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See "Narrative Description of the Business - Industry Conditions - Liability Management Rating Programs".

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business, financial condition, results of operations and cash flows.

Waterflood

The Company may undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities Razor needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If Razor is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs. In addition, Razor may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Company's results of operations.

Expansion into New Activities

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

Changing Investor Sentiment

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board, management and employees. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment the Company or not investing in Razor at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, the Company, may result in limiting Razor's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Forward-Looking Information may Prove to be Inaccurate

Investors are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumptions and uncertainties are found in this AIF under the heading "*Forward-Looking Statements*" above.

DIVIDENDS

The following cash dividends per Common Share were distributed by the Company for each of the three most recently completed financial years:

Dividends	2019	2018
January	$0.1250	—
February	$0.0125	—
March	$0.0125	—
April	$0.0125	—
May	$0.0125	—
June	$0.0125	—
July	$0.0125	—
August	$0.0125	—
September	$0.0125	—
October[1]	$0.0125	$0.1650
	—	$0.0125
November	$0.0125	$0.0125
December	$0.0125	$0.0125
Total	**$0.1500**	**$0.2025**

1. On September 5, 2018, the Company declared a special cash dividend of $0.1650 per Common Share payable on October 5, 2018 to Shareholders of record on October 2, 2018. Subsequent to the special cash dividend, Razor declared a monthly cash dividend of $0.0125 per Common Share starting in October 2018.

Cash Dividend Policy

It is the Company's intention to pay monthly cash dividends to Shareholders of record as of each dividend record date, currently established by the Company to be on or about the 15 day of each calendar month, with the corresponding dividend payment date generally on the last business day of each calendar month.

In determining the level of dividends to be declared, the Board takes into consideration such factors as current and expected future levels of free cash flow, capital expenditures, borrowings and debt repayments, changes in working capital requirements and other factors. Although the Company intends to continue to pay regular monthly dividends to Shareholders, dividends are not guaranteed and are issued at the discretion of the Board.

The Board intends to review this policy on a quarterly basis. Depending on factors that the Board deems relevant from time to time, many of which are beyond the control of the Board and the Company's management team, the Board may change this policy following any such quarterly review or at any other time that the Board deems appropriate. Any such change may result in future cash dividends being reduced or suspended entirely. On February 5, 2020, the Company suspended the payment of dividends effective February 2020 in response to significant price volatility for crude products in the Canadian energy sector.

DESCRIPTION OF SHARE CAPITAL

The Company is authorized to issue an unlimited number of Common Shares without nominal or par value and an unlimited number of preferred shares, issuable in series. As of December 31, 2019, an aggregate of 21,064,466 Common Shares were issued and outstanding. As at the date hereof, there are 21,064,466 fully paid and non-assessable Common Shares issued and outstanding. In addition, there are no warrants or stock options outstanding as at the date hereof.

The holders of the Common Shares are entitled to receive notice of all meetings of Shareholders and to attend and vote the Common Shares at all such meetings. Each Common Share carries with it the right to one vote.

On September 20, 2019, the TSXV approved the Company's application for a renewed Normal Course Issuer Bid (the "NCIB") to repurchase up to 1,039,148 of its Common Shares, representing 5% of the outstanding Common Shares at September 20, 2019, over a 12 month period commencing September 23, 2019 and ending no later than September 22, 2020.

MARKET FOR SECURITIES AND TRADING HISTORY

Following completion of the Arrangement, the Common Shares were listed and posted for trading on the facilities of the TSXV under the symbol "RZE" on February 13, 2017. The following table sets forth the market price ranges and the trading volumes of the Common Shares as reported by the TSXV for the periods indicated:

	Price Range ($ per Common Share)		
2019	High	Low	Volume
January	2.36	2.31	140,139
February	2.62	2.56	154,415
March	2.66	2.61	137,289
April	2.79	2.75	262,055
May	2.41	2.35	241,629
June	2.02	1.96	94,519
July	1.98	1.94	130,057
August	1.77	1.71	144,353
September	1.70	1.60	239,828
October	1.41	1.34	244,119
November	1.01	0.95	301,976
December	1.00	0.95	429,438

DIRECTORS AND OFFICERS

Directors and Officers

The following table sets forth the names and municipalities of residence of the directors and executive officers of the Company as at the date hereof, their respective positions and offices with the Company and date first elected as a director and their principal occupation(s) within the past five years.

Name and Municipality of Residence	Position Presently Held	Director Since	Principal Occupation for Previous Five Years
Doug Bailey Calgary, Alberta, Canada	President, Chief Executive Officer and Director	February 3, 2017	President and Chief Executive Officer of the Company since February 2017. Prior thereto, Mr. Bailey was President and Chief Executive Officer of Razor Private from November 2016 to January 2017, President and Chief Executive Officer of Striker Exploration Corp. ("Striker") from June 2014 to July 2016, and the Chief Financial Officer of Hyperion Exploration Corp. from July 2010 to December 2013.
Frank Muller Calgary, Alberta, Canada	Senior Vice President, Chief Operating Officer and Director	February 3, 2017	Executive Vice President and Chief Operating Officer of the Company since February 2017. Prior thereto, Mr. Muller was Vice President and Chief Operating Officer of Razor Private from November 2016 to January 2017 and Vice President, Exploration and Chief Operating Officer of Striker from June 2014 to June 2016. Mr. Muller was a geological consultant for various oil and gas companies from November 2012 to April 2014. Prior thereto, Mr. Muller was a co-founder and Senior Vice President of WestFire Energy Ltd. from 2007 to 2012.
Kevin Braun Calgary, Alberta, Canada	Chief Financial Officer	—	Chief Financial Officer of the Company since February 2017. Prior thereto, Mr. Braun was Chief Financial Officer of Razor Private in January 2017, the Controller of Brion Energy Corporation from June 2016 to January 2017 and the Controller of Athabasca Oil Corporation from October 2009 to March 2016.
Lisa Mueller Calgary, Alberta, Canada	Vice President, New Ventures	—	Vice President, New Ventures of the Company since May 2017. Prior thereto, Ms. Mueller was President and CEO of Epoch Energy Development from June 2016 to May 2017, and Senior Business Development Manager at Shell from November 2013 to September 2015, and Continuous Improvement Manager for Heavy Oil at Shell from September 2012 to November 2013.
Devin Sundstrom Calgary, Alberta, Canada	Vice President, Production	—	Vice President, Production of the Company since February 2017. Prior thereto, Mr. Sundstrom was Vice President, Production of Razor Private in January 2017, Vice President, Production at Long Run Exploration Ltd. from October 2012 to November 2016 and Vice President, Production at Guide Exploration Ltd. from November 2011 to October 2012.
Stephen Sych Calgary, Alberta, Canada	Vice President, Operations	—	Vice President, Operations of the Company since February 2017. Prior thereto, Mr. Sych was Vice President, Operations of Razor Private from December 2016 to January 2017 and Production Manager of Arsenal Energy Inc. from June 2010 to December 2016.
Sanjib Gill (1)(3) Calgary, Alberta, Canada	Director	February 3, 2017	Since April 2019, Mr. Gill has been a partner at Stikeman Elliott LLP, a national law firm, practicing law primarily in the areas of corporate finance, mergers and acquisitions. Prior thereto, Mr. Gill was a partner at another national law firm since 2006.
Sonny Mottahed (1)(2)(3) Calgary, Alberta, Canada	Director	February 3, 2017	Chief Executive Officer and Managing Partner of Black Spruce Merchant Capital since April 2012. Prior thereto, Mr. Mottahed was the Managing Director, Investment Banking & Head of International Oil & Gas at Raymond James Ltd. from May 2008 to March 2012.
Vick Saxon (2)(3) Calgary, Alberta, Canada	Director	February 3, 2017	Director for VZFOX Canada Group of Companies. Mr. Saxon also serves on the Board of Directors for a boutique venture capital firm and is a co-founder of V'NS Limited (an oil field equipment supply company).

Notes:
(1) Member of the Audit Committee.
(2) Member of the Reserves and Environment Committee.
(3) Member of the Corporate Governance and Compensation Committee.

As at the date hereof, the directors and officers of the Company, and their associates and affiliates, as a group, whether beneficial, direct or indirect, own 6,127,961 Common Shares, representing approximately 29.09% of the currently outstanding Common Shares.

The directors listed above will hold office until the next annual meeting of the Company or until their successors are elected or appointed.

Cease Trade Orders and Bankruptcies

No director or executive officer of the Company is, or within ten years prior to the date of this AIF has been, a director, a chief executive officer or a chief financial officer of any company (including the Company), that:

a) was subject to: (i) a cease trade order; (ii) an order similar to a cease trade order; or (iii) an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days (collectively, an "Order"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or

b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Except as set forth below, no director, executive officer or, to the best of the Company's knowledge, any Shareholder holding a sufficient number of securities of the Company to affect materially control of the Company, is, or within ten years prior to the date of this AIF has been, a director or executive officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

No director or executive officer of the Company or a Shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has, within the past ten years prior to the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such person.

Penalties and Sanctions

No director or executive officer of the Company of the Company, or a Shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain of the directors and officers of the Company are also directors, officers and/or promoters of other reporting and non-reporting issuers, which may give rise to conflicts of interest. In accordance with corporate laws, directors who have an interest in a contract or a proposed contract with the Company are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Company. Some of the directors of the Company have other employment or other business or time restrictions placed on them and accordingly, these directors of the Company will only be able to devote part of their time to the affairs of the Company. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA. As of the date hereof, the Company is not aware of any existing or potential material conflicts of interest between the Company and any director or officer of the Company.

Sanjib Gill, a director of the Company, is a partner of the national law firm Stikeman Elliott LLP, which law firm renders legal services to the Company. The Board of Directors does not believe that any of the activities undertaken by Mr. Gill or by Stikeman Elliott LLP interfere, or could be perceived to interfere, in any material way, with his ability to act with a view to the best interests of Razor.

EXTERNAL AUDITOR SERVICE FEES

The following table summarizes the fees billed to the Company by its auditors, KPMG LLP (**"KPMG"**), for external audit and other services during the periods indicated:

($000's)	2019	2018
Audit fees [1]	160,000	242,525
Audit-related fees [2]	82,000	73,575
Tax fees [3]	2,600	6,815
All other fees [4]	—	—
	244,600	322,915

Notes:
1) Audit fees were for professional services rendered by KPMG for the audit of the Company's annual financial statements and review of the Company's interim quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements.
2) Audit-related fees are for assurance and related services provided by KPMG that are reasonably related to the performance of the audit of the Company's financial statements and not reported under "Audit fees" above.
3) Tax fees were for tax compliance, tax advice and tax planning.
4) All other fees related to products and services provided by KPMG other than those described as "Audit fees", "Audit-related fees" and "Tax fees".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

On March 20, 2017, Malibu Energy Ltd., Topanga Resources Ltd. and North Shore Petroleum Ltd. (the "**Plaintiffs**") filed a statement of claim commencing Action 1701-01476 (the "**Action**") in the Judicial Centre of Calgary of the Court of Queen's Bench of Alberta against the Company and its Chief Executive Officer (the "**Razor Defendants**") and others. As against the Razor Defendants, the Plaintiffs allege, in essence, that the Razor Defendants were provided with confidential information by certain other defendants about certain petroleum and natural gas assets that a vendor had agreed (subject to certain conditions) to sell to the Plaintiffs. The Plaintiffs claim, jointly and severally against all of the defendants, $165,290,000 in damages, $540,000 in punitive damages, an interlocutory and permanent injunction restraining Razor from acquiring the assets, interest and costs.

On March 28, 2017, the Razor Defendants filed a statement of defence in which they vigorously denied every allegation made against them.

On April 21, 2017, the Plaintiffs discontinued their claim against the Company's Chief Executive Officer.

All parties have now produced their documents and questioning was commenced. Questioning of Razor's witnesses took place in February 2019. Questioning of the remaining Defendants and of the Plaintiff's took place in March 2019. Undertakings given at questioning for discovery have now been answered by all parties.

The Company is of the view that the claim is without merit, that the damages claimed by the Plaintiffs are excessive and grossly exaggerated and that an injunction is unlikely to be granted to prohibit the acquisition of the specified assets. Also see "*Risk Factors - Legal Proceedings*".

Other than as set forth above, there are no legal proceedings material to the Company to which the Company is a party or of which any of its property is the subject matter, and there are no such proceedings known to the Company to be contemplated. There are no penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the most recently completed financial year, there are no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decisions, and there are no settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

To the best of the Company's knowledge, except as disclosed herein regarding AIMCo's interest in the Amended Term Loan Facility, there are no material interests, direct or indirect, of directors or executive officers of the Company, any Shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years of the Company or during the current financial year which has materially affected, or is reasonably expected to materially affect, the Company.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar is Alliance Trust Company at its principal office in Calgary, Alberta.

MATERIAL CONTRACTS

Except as disclosed herein and other than contracts entered into in the ordinary course of business, there have been no material contracts entered into by the Company within the most recently completed financial year, or before the most recently completed financial year that are still in effect.

PROMOTERS

Doug Bailey may be considered to be a promoter of the Company pursuant to applicable securities laws. As at the date hereof, Doug Bailey beneficially owns, directly or indirectly, 1,442,261 Common Shares representing approximately 6.85% of the outstanding Common Shares.

INTERESTS OF EXPERTS

Reserve estimates contained in this Annual Information Form have been prepared by Sproule. As at December 31, 2019, the effective date of those estimates, and as of the date hereof, the principals, directors, officers and associates of Sproule, as a group, owned, directly or indirectly, less than one percent of the outstanding Common Shares.

KPMG LLP, the Company's auditors, are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or any associate or affiliate of the Company.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's information circular for the Company's most recent Shareholder's meeting that involved the election of directors. Additional financial information is contained in the Company's consolidated financial statements and the related management's discussion and analysis for the year ended December 31, 2019.

Additional copies of this AIF and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Company at its offices at 800, 500 - 5th Avenue S.W., Calgary, Alberta, T2P 3L5 or by phone at (403) 262-0242.

SCHEDULE A

FORM 51-101F2

REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Razor Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	December 31, 2019	Canada				
Total			**Nil**	**242,720**	**Nil**	**242,720**

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

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Razor Energy Corp. (As of December 31, 2019)".

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 24, 2020

Original Signed by Liam O'Brien, P.Eng.

Liam O'Brien, P.Eng.
Petroleum Engineer

Original Signed by Tamara Warren, P.Eng.

Tamara Warren, P.Eng.
Petroleum Engineer

Original Signed by Brian G. Trieber, P.L.(Geol.)

Brian G. Trieber, P.L.(Geol.)
Senior Technologist

Original Signed by Cameron P. Six, P.Eng.

Cameron P. Six, P.Eng.
CEO

Original Signed by Alec Kovaltchouk, P.Geo.

Alec Kovaltchouk, P.Geo.
VP, Geoscience

SCHEDULE B

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

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

Management of Razor Energy Corp. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated and reviewed the Company's reserves data. The report of the independent qualified reserves evaluators is presented in the Annual Information Form of the Company for the year ended December 31, 2019.

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

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;
(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
(c) the content and filing of this report.

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

(signed) *"Doug Bailey"*

President, Chief Executive Officer and Director

(signed) *"Frank Muller"*

Senior Vice President, Chief Operating Officer and Director

(signed) *"Vick Saxon"*

Director and Chair of Reserves and Environment Committee

(signed) *"Sonny Mottahed"*

Director

Dated April 28, 2020