ANNUAL INFORMATION FORM

For the year ended December 31, 2021

March 29, 2022

TABLE OF CONTENTS

NOTES TO READER

General

In this Annual Information Form (AIF), unless otherwise indicated or the context otherwise requires, the terms "we", "us", "our", and "the Company" refer to Prairie Provident Resources Inc., as parent corporation, together with its wholly-owned subsidiaries, Prairie Provident Resources Canada Ltd. (formerly Lone Pine Resources Canada Ltd.) and Lone Pine Resources Inc. See "*Company Overview and Background*" below.

Unless otherwise indicated, information in this AIF is given as at the end of the Company's most recently completed financial year, being December 31, 2021.

Defined Terms

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms shall have the respective meanings set forth below:

"**ABCA**" means the *Business Corporations Act* (Alberta);

"**API**" means the American Petroleum Institute, and "**°API**" is an indication of the specific gravity of crude oil measured on the API gravity scale;

"**Board of Directors**" means the board of directors of the Prairie Provident;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society);

"**Common Shares**" means the common shares in the capital of Prairie Provident;

"**gross**" means: (i) in relation to the Company's interest in production and reserves, its "company gross reserves", which are the Company's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of the Company; (ii) in relation to wells, the total number of wells in which the Company has an interest; and (iii) in relation to properties, the total area of properties in which the Company has an interest;

"**IFRS**" means International Financial Reporting Standards;

"**LPR Canada**" means Lone Pine Resources Canada Ltd., an Alberta corporation that was subsequently renamed Prairie Provident Resources Canada Ltd. and is an amalgamation predecessor of PPR Canada;

"**LPRI**" means Lone Pine Resources Inc., a Delaware corporation that is wholly-owned by Prairie Provident and directly holds a controlling equity interest in PPR Canada;

"**net**" means: (i) in relation to the Company's interest in production and reserves, the Company's working interest (operating and non-operating) share after deduction of royalties obligations, plus the Company's royalty interest in production or reserves; (ii) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and (iii) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company;

"**NGLs**" means natural gas liquids;

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

"**PPR Canada**" means Prairie Provident Resources Canada Ltd. (formerly Lone Pine Resources Canada Ltd.), an Alberta corporation that is a wholly-owned subsidiary of Prairie Provident (direct and indirect through LPRI) and is the amalgamated corporation continuing from amalgamations with Arsenal Energy Inc. on January 1, 2017 and with Marquee Energy Ltd. on November 21, 2018;

"**Prairie Provident**" means Prairie Provident Resources Inc.; and

"**TSX**" means the Toronto Stock Exchange.

Certain other terms used but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Barrel of Oil Equivalency Measures
This AIF includes various references to "barrels of oil equivalent" (boe).

We have adopted the industry-standard conversion ratio of six Mcf to one bbl when converting natural gas quantities to boes. Boes may be misleading, though, particularly if used in isolation. **A boe conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead or plant gate.**

Although the six-to-one conversion factor is an industry-accepted norm, it is not reflective of price or market value differentials between product types. Based on current commodity prices, the value ratio between natural gas and oil is significantly different than the six-to-one ratio based on energy equivalency. Accordingly, a conversion ratio based on six Mcf of natural gas to one bbl of oil may be misleading as an indication of value.

Currency References
Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars and the term "$000s" means thousands of dollars.

Abbreviations
Following is a list of certain abbreviations used in this AIF.

Crude Oil and Natural Gas Liquids:		Natural Gas:	
bbl	barrel	Mcf	thousand cubic feet
bbl/d	barrels per day	MMcf	million cubic feet
Mbbl	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbl	million barrels	Btu	British thermal unit
NGLs	natural gas liquids	MMbtu	million British thermal units
		m^3	cubic metres

Barrels of Oil Equivalent:	
boe	barrels of oil equivalent of natural gas on the basis of 1 boe for 6 Mcf of natural gas
Mboe	one thousand barrels of oil equivalent
MMboe	one million barrels of oil equivalent
boe/d	barrels of oil equivalent per day

Conversion Ratios
In this AIF, certain measurements may be given in Standard Imperial Units or in International System of Units (or metric units). The following table sets forth certain standard conversions between the two measurement systems.

To Convert From	To	Multiply By
Mcf	thousand cubic metres ("10^3m^3")	0.0282
thousand cubic metres	Mcf	35.494
Bbl	cubic metres ("m^3")	0.159
cubic metres	bbl	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

RESERVES DATA DISCLOSURE

The reserves attributed herein to the Company's current and former properties are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater or less than those estimated, and the difference may be material.

Similarly, the future net revenues relating to reserves as presented in this AIF are also estimates only, and it should not be assumed that they represent the fair market value of such reserves. There is no assurance that the forecast prices and cost assumptions applied by the independent qualified reserves evaluator in evaluating the reserves will be attained, and variances between actual and forecast prices and costs could be material.

In addition, estimates of reserves and related future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

The determination of oil and gas reserves involves estimating subsurface accumulations of oil, natural gas and NGLs that cannot be measured in an exact manner. The preparation of estimates is subject to an inherent degree of associated risk and uncertainty, including factors that are beyond our control. The estimation and classification of reserves is a complex process involving the application of professional judgment combined with geological and engineering knowledge to assess whether specific classification criteria have been satisfied. It requires significant judgments based on available geological, geophysical, engineering, and economic data as well as forecasts of commodity prices and anticipated costs. As circumstances change and additional data becomes available, whether through the results of drilling, testing and production or from economic factors such as changes in product prices or development and production costs, reserves estimates also change. Revisions may be positive or negative.

In accordance with the requirements of NI 51-101, disclosure of reserves contained in this AIF uses the applicable terminology and reserves categories set out in the COGE Handbook.

All estimates of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as general and administrative, overhead, interest and other miscellaneous expenses.

Estimates of reserves and future net revenue have been made assuming that development of each property in respect of which the estimate is made will occur, without regard to the likely availability of funding required for that development.

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

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

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

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories.

- "***Developed reserves***" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

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

  - "***Developed non-producing reserves***" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

FORWARD-LOOKING STATEMENTS

This AIF contains forward-looking statements and forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements are typically (but not necessarily) identified by words such as "anticipate", "believe", "plan", "budget", "continue", "potential", "project", "estimate", "intend", "expect", "attempt", "target", "seek", "may", "will", "should", or similar words suggesting future outcomes. Although the Company believes that the forward-looking statements contained herein are reasonable based on currently available information, undue reliance should not be placed on them as they are subject to known and unknown risks and uncertainties, many of which are beyond the Company's control. Forward-looking statements are not guarantees of future outcomes.

In particular, this AIF and other documents filed by Prairie Provident with securities regulatory authorities in Canada contain forward-looking statements regarding, among other things:

- business plans and strategies;
- plans for and results of exploration and development activities;
- the source of funding for the Company's activities, including development costs;
- expectations regarding the Company's ability to raise capital and to add reserves and grow production through acquisitions, exploration and development;
- estimated quantities of natural gas, oil, and NGLs reserves within the Company's properties and recovery rates;
- estimated net present value of future net revenues from identified reserves;
- market prices for oil, natural gas and NGLs;
- capital expenditures;
- exploration, development, operating and transportation costs;
- oil, natural gas and NGL production estimates;
- sources of oil, natural gas and NGL production growth;
- supply and demand for oil, natural gas and NGLs;
- foreign currency exchange rates and interest rates;

- treatment under governmental regulatory regimes and tax, environmental and other laws;
- future operating and financial results;
- realization of the anticipated benefits of acquisitions and dispositions;
- performance characteristics of the Company's oil and gas properties;
- commodity prices and costs;
- planned construction and expansion of facilities;
- drilling and completion plans;
- secondary recovery projects;
- availability of rigs, equipment and other goods and services;
- procurement of drilling licenses and other necessary authorizations;
- reserves life measurements; and
- well abandonment costs and other abandonment and reclamation costs.

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

- general economic, market and business conditions in Canada, the United States and globally;
- variance of the Company's actual capital costs, operating costs and economic returns from those anticipated;
- risks inherent in oil and gas operations, including production risks associated with sour hydrocarbons;
- volatility in market prices for oil, natural gas and NGLs;
- differentials between benchmark commodity prices and those realizable by the Company;
- operational dependence on other industry participants;
- uncertainties associated with estimating oil, natural gas and NGL reserves;
- uncertainties associated with estimating production of oil, natural gas and NGLs from the Company's lands;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, skilled personnel and services;
- unanticipated operating events that can reduce production or cause production to be shut in or delayed;
- incorrect assessments of the value of acquisitions or dispositions;
- geological, technical, engineering, drilling, completion and processing problems;
- increased operating costs and capital costs;

- changes in laws and governmental regulations;
- actions by governmental authorities, including increases in royalties or taxes;
- accessibility of capital when required and on acceptable terms;
- changes in interest rates or currency exchange rates;
- stock market volatility;
- ability to obtain required regulatory approvals and third party consents on a timely basis and on satisfactory terms; and
- those factors discussed under "Risk Factors" in this AIF.

The foregoing list of factors is not and should not be construed as exhaustive.

In addition, information and statements relating to "reserves" or other "resources" are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves or other resources described exist in the quantities predicted or estimated and, in the case of reserves, can profitably be produced in the future. See also "*Reserves Data Disclosure*".

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on assumptions, and are subject to known and unknown risks and uncertainties, both general and specific, many of which are beyond our control, that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations contained in the forward-looking statements or upon which they are based will in fact occur or be realized. Actual results will differ, and the difference may be material and adverse to the Company and its shareholders.

Forward-looking statements are based on the Company's current beliefs, as well as assumptions made by and information currently available to the Company concerning, such matters as: the accuracy of geological and geophysical data and interpretations of that data; future oil, natural gas and NGLs prices at which the Company's production may be sold; the ability of the Company to achieve drilling success consistent with management's expectations; the timing and cost of pipeline and facility construction and expansion and the ability of the Company to secure adequate product transportation; future capital requirements and expenditures; future exchange rates; the accessibility and cost of capital (including credit facilities); the ability to obtain financing on acceptable terms; future exploration, development, operating and transportation costs; the ability to economically produce oil and gas from its properties and the timing and cost to do so; the ability to add production and reserves through development and exploration activities; the ability to obtain qualified staff, equipment, services and supplies in a timely and cost-efficient manner; applicable regulatory requirements, including with respect to environmental protection; applicable royalty rates, and available means by which to bring the Company's production to market. Although management considers its beliefs and assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

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

All forward-looking statements contained herein are expressly qualified by this cautionary statement.

COMPANY OVERVIEW AND BACKGROUND

General

Prairie Provident is a Calgary-based public company engaged in the exploration and development of oil and natural gas properties in Alberta. Our strategy is to optimize cash flow from our existing assets, grow a base waterflood business in Evi (Slave Point Formation) and Michichi (Banff Formation) providing stable low decline cash flow, and organically develop a new complementary play to facilitate reserves and production growth. The Princess area in Southern Alberta continues to provide short-cycle returns through successful development of the Glauconite and Ellerslie Formations. We maintain a high working interest in a well-balanced portfolio of oil and gas properties.

Our business was previously conducted by Lone Pine Resources Inc. and its subsidiaries, which completed a business combination with Arsenal Energy Inc. in September 2016 to continue as Prairie Provident.

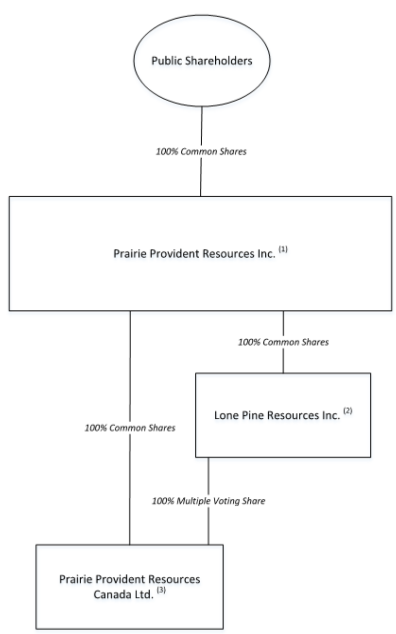
Our business today is conducted primarily through PPR Canada, which owns and operates substantially all of our oil and gas assets and is a wholly-owned subsidiary of Prairie Provident. PPR Canada is the amalgamation successor to Lone Pine Resources Canada Ltd., Arsenal Energy Inc. and, upon its acquisition by Prairie Provident in November 2018, Marquee Energy Ltd.

Our reserves, producing properties and principal exploration prospects are located in the province of Alberta. Our head office is located at 1100, 640 - 5th Avenue S.W., Calgary, Alberta. Our registered office is located at 4500 Bankers Hall East, 855 - 2nd Street S.W., Calgary, Alberta.

The Common Shares are listed on the TSX under the symbol "PPR".

Intercorporate Relationships

Prairie Provident is the parent corporation of the corporate group consisting primarily of itself, PPR Canada and LPRI, which are its only material subsidiaries. The following diagram sets out the intercorporate ownership structure of Prairie Provident and its material subsidiaries.



Notes:

(1) Alberta corporation.

(2) Delaware corporation that holds a controlling equity interest in Prairie Provident Resources Canada Ltd.

(3) Alberta corporation continuing from the amalgamation of Prairie Provident Resources Canada Ltd. and Marquee Energy Ltd. on November 21, 2018, and the amalgamation successor to (among others) Lone Pine Resources Canada Ltd. and Arsenal Energy Inc.

General Development of our Business

The Company's business over the last three completed financial years has been focused on the exploration and development of its oil and gas properties, particularly its core areas at Princess and Michichi in Southern Alberta and at Evi in Northern Alberta. See "Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties". The pace of drilling activity over such period has generally reflected the prevailing commodity price environment, with the Company drilling 5 wells in 2021 after previously having drilled only one well in 2020 as commodity prices rebounded during 2021. A total of 3 wells were drilled during 2019.

Prairie Provident's properties include those acquired in November 2018 through the corporate acquisition of Marquee Energy Ltd. by plan of arrangement under the ABCA.

The Company has financed its capital program since 2019 through internally generated cash flows and borrowings under credit arrangements between PPR Canada and Prudential Capital Group ("**Prudential**"). These credit arrangements are comprised of (i) a senior secured revolving note facility (the **"Revolving Facility"**) with a current borrowing base of US$53.8 million, and (ii) three series of senior subordinated notes issued in 2017, 2018 and 2020, respectively. See "*Capital Structure and Outstanding Securities – Debt Securities*".

In October 2019, the maturity date of the Revolving Facility was extended from October 31, 2020 to April 30, 2021.

On December 21, 2020, PPR Canada entered into agreements with Prudential providing for: (i) a further extension of the maturity date of the Revolving Facility from April 30, 2021 to December 31, 2022; (ii) an extension of the maturity date of the outstanding US$28.5 million original principal amount of senior subordinated notes issued in 2017 and 2018 (the "**Original Notes**") to June 30, 2023; (iii) an issue of US$11.4 million original principal amount of new senior subordinated notes due December 2026 (the "**Additional Notes**" and, together with the Original Notes, the "**Subordinated Notes**"), the net proceeds of which were applied against borrowings under the Revolving Facility; (iv) a change in the borrowing base under the Revolving Facility from US$60.0 million to US57.7 million, subject to reduction to US$53.8 million on December 31, 2021; (v) amendments to existing agreements to, among other things, reduce cash interest costs and relax and reset financial covenants; and (vi) an issue of warrants (the "**Lender Warrants**") to purchase up to 34,292,360 Common Shares (representing 19.9% of the total number of Common Shares then outstanding) at a price of $0.0192 per share until December 21, 2028. Warrants to purchase up to an aggregate of 8,318,000 Common Shares, previously issued by the Company in conjunction with the sale of the Original Notes in 2017 and 2018, were cancelled.

On December 29, 2021, the note purchase agreements governing the Revolving Facility and Subordinated Notes were further amended to, among other things, extend the maturity date of the Revolving Facility from December 31, 2022 to December 31, 2023, and the maturity date of the Original Notes from June 30, 2023 to June 30, 2024. The maturity date of the Additional Notes remains December 21, 2026.

See "*Capital Structure and Outstanding Securities – Debt Securities*" and "*Capital Structure and Outstanding Securities – Convertible Securities*".

Business Plan and Strategy

We are committed to maintaining a flexible financial position through capital discipline, operational efficiency and a robust hedging program. Our strategy focuses on developing core areas with development drilling activities as well as improving profitability through operating cost improvements. Implementing waterflood development schemes in Evi and Michichi is expected to create sustainable reserves and cash flow growth. The stable cashflow generating capability of our core assets is anticipated to fund future development capital and reduce debt.

Marketing and Delivery Commitments

Our natural gas production is generally sold on a daily and/or monthly basis, priced in reference to published market indices. Our oil production is also generally sold under month-to-month contracts at prices based upon refinery postings, and is typically sold at or near the wellhead. Our NGLs production is typically sold under term agreements at gas processing facilities at prices based on the average of posted prices less pipeline tariffs and fractionation fees. We believe that the loss of one or more of our current oil, natural gas or NGLs purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by another purchaser, absent a broad market disruption. For information on financial contractual obligations relating to the Company's transportation agreements, please see Note 22 “Commitments and Contingencies” in the Company's annual financial statements for the year ended December 31, 2021, available on the Prairie Provident's website at www.ppr.ca and under its issuer profile on SEDAR at www.sedar.com.

Employees

As of December 31, 2021, the Company had 38 full-time employees and 27 contractors (on both full-time and part-time bases). In the ordinary course of our business we require the services of accountants, landmen, engineers, field operators and other professionals to aid in specialized areas and to explore and analyze hydrocarbon prospects and to determine a method in which prospects may be developed in a cost-effective manner. We also rely on the owners and operators of drilling and completion equipment to drill and develop our prospects to production. We have been able to acquire the services of these persons as needed in the past and believe that it will be able to continue to acquire these services as needed in the future.

Competition

The Company encounters competition in all aspects of its business, including acquisition of properties and oil and gas leases, marketing oil, natural gas and NGLs, obtaining services and labor and securing drilling rigs and other equipment necessary for maintaining, drilling and completing wells. Our ability to add reserves in the future will depend on our ability to generate successful prospects on our existing properties, execute on organic development programs and acquire additional producing properties and/or prospects for future development and exploration. Many of the companies that we compete with have substantially larger workforce and greater financial and operational resources than the Company. Because of the nature of our oil and gas assets and management's experience in exploiting its reserves and acquiring properties, management believes that the Company effectively competes in its markets. See "*Risk Factors – Competitive Risk*" in this AIF.

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 governmental authorities impose road bans that restrict the movement of drilling and service rigs and other heavy equipment, thereby limiting or temporarily halting drilling and producing activities and other oil and gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Extreme cold weather may cause operational outages and reduced well performance, and ultimately lost revenue. Restoring downtime production could also materially increase our operating costs. Such seasonal anomalies can also adversely affect our ability to meet drilling objectives and capital commitments, and may increase competition for equipment, supplies and personnel during the winter months, which could lead to shortages and increased costs or delay or temporarily halt operations.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The estimates of the Company's proved reserves and probable reserves and related future net revenue (collectively, "**reserves data**") set forth below is based upon a report dated January 17, 2022 prepared by Sproule Associates Limited ("**Sproule**") evaluating the crude oil, natural gas and NGLs reserves of the Company as at December 31, 2021 using forecast prices and costs (the "**Sproule Report**"). The preparation date of the Sproule Report, being the most recent date to which information relating to the period ending December 31, 2021 was considered in its preparation, was January 11, 2022. Sproule evaluated proved and probable reserves attributable to the Company's interest in 100% of its properties and the net present value of estimated future cash flow from such reserves, based on forecast price and cost assumptions, in accordance with NI 51-101 and, pursuant thereto, the standards contained in the COGE Handbook.

We engaged Sproule to provide an evaluation of proved reserves and probable reserves only. No attempt was made to evaluate possible reserves or any resources other than proved reserves and probable reserves.

All of our reserves are located in Canada in the province of Alberta. We do not have significant unconventional reserves (bitumen, synthetic oil, coal bed methane, etc.).

A Report on Reserves Data by Independent Qualified Reserves Evaluator (Form 51-101F2) from Sproule and a Report of Management and Directors on Oil and Gas Disclosure (Form 51-101F3), each in the form required under NI 51-101, are attached as Schedules A and B, respectively, to this AIF.

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

See "*Reserves Data Disclosure*", "*Risk Factors*" and "*Forward-Looking Statements*".

Reserves Data

Reserves Data (Forecast Prices and Costs)

The following tables set forth the Company's reserves data estimates as of December 31, 2021, as evaluated by Sproule using forecast prices and costs.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2021

FORECAST PRICES AND COSTS

	Light & Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED												
Developed Producing	5,466	4,951	474	402	17,885	16,109	298	266	284	231	9,254	8,313
Developed Non-Producing	1640	1436	—	—	687	649	—	—	16	14	1770	1558
Undeveloped	6,221	5,635	304	251	14,371	13,341	—	—	232	205	9,152	8,314
TOTAL PROVED	13,327	12,021	778	653	32,943	30,099	298	266	531	449	20,176	18,185
PROBABLE	6,053	5,119	511	427	15,755	14,207	75	67	246	200	9,448	8,125
TOTAL PROVED PLUS PROBABLE	19,379	17,141	1,289	1,080	48,698	44,306	374	333	777	649	29,624	26,309

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2021

FORECAST PRICES AND COSTS
(Before and After Income Taxes)

Net Present Values of Future Net Revenue ($000s)

	Before Income Taxes - Discounted at (%/year)					After Income Taxes - Discounted at (%/year)					Unit Value [(1)] Before Income Taxes - Discounted at 10%/year
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**$/boe**
PROVED											
Developed Producing	(17,773)	92,938	106,191	102,090	95,049	(17,773)	92,938	106,191	102,090	95,049	12.77
Developed Non-Producing	65,366	32,568	17,557	9,550	4,881	65,366	32,568	17,557	9,550	4,881	11.27
Undeveloped	206,954	152,430	113,969	86,521	66,450	206,954	152,430	113,969	86,521	66,450	13.71
TOTAL PROVED	254,548	277,937	237,718	198,161	166,379	254,548	277,937	237,718	198,161	166,379	13.07
PROBABLE	313,410	227,146	176,493	143,488	120,451	313,410	227,146	176,493	143,488	120,451	21.72
TOTAL PROVED PLUS PROBABLE	567,958	505,082	414,210	341,649	286,830	567,958	505,082	414,210	341,649	286,830	15.74

Note:

(1) Unit values are based on net reserves.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2021

FORECAST PRICES AND COSTS ($000s)

Reserves Category	Revenue [(1)]	Royalties [(2)]	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
TOTAL PROVED	1,303,587	122,751	522,073	168,253	235,962	254,548	—	254,548
TOTAL PROVED PLUS PROBABLE	1,924,611	209,236	689,038	218,520	239,859	567,958	—	567,958

Notes:

(1) Total Revenue includes company revenue before royalty and includes other income.

(2) Royalties include Crown, freehold, overriding royalties and freehold mineral tax.

FUTURE NET REVENUE BY PRODUCTION GROUP
as of December 31, 2021

FORECAST PRICES AND COSTS

		Future Net Revenue Before Income Taxes [(4)] (discounted at 10%/year)	
Reserves Category	**Production Type**	**$000s**	**$/boe**
TOTAL PROVED	Light and Medium Crude Oil [(1)]	202,852	12.98
	Heavy Crude Oil [(1)]	23,036	26.97
	Conventional Natural Gas [(2)]	11,495	6.96
	Coal Bed Methane [(3)]	335	6.91
	Total Proved	237,718	
TOTAL PROVED PLUS PROBABLE	Light and Medium Crude Oil [(1)]	364,828	16.01
	Heavy Crude Oil [(1)]	35,401	25.15
	Conventional Natural Gas [(2)]	13,594	6.63
	Coal Bed Methane [(3)]	387	6.37
	Total Proved Plus Probable	414,210	

Notes:

(1) Including solution gas (gas dissolved in crude oil) and associated by-products.

(2) Non-associated and associated gas. Including associated by-products but excluding solution gas.

(3) Including associated by-products but excluding solution gas.

(4) Unit values are based on net reserves for each production group.

Notes to Reserves Data Tables:

(1) Columns may not add due to rounding.

(2) All estimates of reserves data presented herein have been prepared in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook. Relevant definitions are set out in the following notes.

(3) Reserve estimates of natural gas include associated gas (the gas cap overlying a crude oil accumulation in a reservoir) and non-associated gas (an accumulation of natural gas in a reservoir where there is no crude oil).

(4) Unit values are based on net reserves volumes before income tax.

(5) Future Development Costs shown are associated with booked reserves in the Sproule Report and do not necessarily represent the Company's full exploration and development budget.

(6) "***Reserves***" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, with the use of established technology and under specified economic conditions which are generally accepted as being reasonable, and shall be disclosed. Reserves are classified according to the degree of uncertainty associated with the estimate.

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

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

(9) "***Developed reserves***" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

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

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

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

(13) "***Forecast prices and costs***" are those: (i) generally acceptable as being a reasonable outlook of the future; and (ii) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in clause (i). The table under "Pricing Assumptions" below identifies benchmark reference prices that apply to the Company.

(14) "***Operating costs***" (or "***Production costs***") means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. Lifting costs become part of the cost of oil and gas produced. Examples of operating costs or production costs are: (i) costs of labour to operate the wells and related equipment and facilities; (ii) costs of repairs and maintenance; (iii) costs of materials, supplies and fuel consumed, and supplies utilized, in operating the wells and related equipment and facilities; (iv) costs of workovers; (v) property taxes and insurance costs applicable to properties and wells and related equipment and facilities; and (vi) taxes, other than income and capital taxes.

(15) "***Exploration costs***" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

(16) "***Development costs***" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

(17) "***Future income taxes***" are estimated: (i) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities; (ii) without deducting estimated future costs that are not deductible in computing taxable income; (iii) taking into account estimated tax credits and allowances; and (iv) applying to the future pre-tax net cash flows relating to the Company's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

(18) "***Exploratory well***" means a well that is not a development well, a service well or a stratigraphic test well.

(19) "***Development well***" means a well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

(20) "***Service well***" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

(21) "***Stratigraphic test well***" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as: (i) "exploratory type" if not drilled into a proved property; or (ii) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

Pricing and Inflation Rate Assumptions

The reserves data estimates contained herein are based on forecast prices and costs, using Sproule's pricing, exchange rate and inflation rate assumptions as of December 31, 2021.

The forecast price and cost assumptions used in estimating the Company's reserves data assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The following table sets forth commodity benchmark reference pricing, inflation rates and exchange rates utilized by Sproule in the Sproule Report, which were provided by Sproule and was Sproule's then-current standard price forecast effective December 31, 2021. Price offsets and differentials for each property were determined by comparing actual historical benchmark prices to actual prices received at the property.

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
USED IN PREPARING RESERVES DATA
(Forecast Prices and Costs)**

	Crude Oil			Natural Gas	NGLs			Inflation Rate		
Year	**WTI** [(1)] ($US/bbl)	**Canadian Light Sweet** [(2)] ($Cdn/bbl)	**Western Canada Select** [(3)] ($Cdn/bbl)	**AECO-C (NIT) Spot** ($Cdn/ MMBtu)	**Edmonton Propane** ($Cdn/bbl)	**Edmonton Butane** ($Cdn/bbl)	**Edmonton Condensate (Pentanes Plus)** ($Cdn/bbl)	**Operating Costs** (%/Year)	**Capital Costs** (%/Year)	**Exchange Rate** ($US/$Cdn)
Historical										
2017	50.95	61.85	50.24	2.19	28.77	44.11	67.21	1.7%	2.4%	0.77
2018	64.77	68.49	52.34	1.53	27.00	33.65	79.31	2.4%	4.2%	0.77
2019	57.02	68.87	58.77	1.80	17.16	23.71	71.39	-0.7%	0.4%	0.75
2020	39.40	45.39	35.59	2.24	16.31	21.87	49.85	-5.0%	-5.0%	0.75
2021	67.91	80.31	68.80	3.64	43.39	51.64	85.88	3.3%	6.6%	0.80
Forecast										
2022	73.00	86.25	75.63	3.88	38.64	54.75	91.25	0.0%	0.0%	0.80
2023	70.00	82.40	71.56	3.36	36.05	50.75	87.50	2.0%	2.0%	0.80
2024	68.00	79.80	68.74	3.02	34.68	49.30	85.00	2.0%	2.0%	0.80
2025	69.36	81.39	70.12	3.08	35.37	50.29	86.70	2.0%	2.0%	0.80
2026	70.75	83.02	71.52	3.14	36.08	51.29	88.43	2.0%	2.0%	0.80
2027	72.16	84.68	72.95	3.21	36.80	52.32	90.20	2.0%	2.0%	0.80
2028	73.61	86.38	74.41	3.27	37.53	53.36	92.01	2.0%	2.0%	0.80
2029	75.08	88.10	75.90	3.34	38.28	54.43	93.85	2.0%	2.0%	0.80
2030	76.58	89.87	77.42	3.40	39.05	55.52	95.72	2.0%	2.0%	0.80
2031	78.11	91.66	78.96	3.47	39.83	56.63	97.64	2.0%	2.0%	0.80
2032	79.67	93.50	80.54	3.54	40.63	57.76	99.59	2.0%	2.0%	0.80
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0%	2.0%	

Notes:

(1) West Texas Intermediate (WTI) at Cushing, Oklahoma, 40^{o} API, 0.4% sulphur.

(2) Canadian Light Sweet at Edmonton, Alberta, 40^{o} API, 0.3% sulphur.

(3) Western Canada Select at Hardisty, Alberta, 20.5^{o} API.

The weighted average historical prices realized by the Company for the year ended December 31, 2021 were $71.83 per bbl for light and medium crude oil, $72.12 for heavy crude oil, $3.73 per Mcf for natural gas and $57.25 per bbl for NGLs. For further information regarding the Company's production mix in 2021, see "– *Other Oil and Gas Information – Production History*" below.

Reserves Reconciliation

The following table sets forth a year-over-year reconciliation of the Company's estimated gross reserves as of December 31, 2021 to the prior year's estimates, based on forecast prices and costs, by principal product type.

	Light & Medium Crude Oil			Heavy Crude Oil			Conventional Natural Gas			Coal Bed Methane			Natural Gas Liquids			Total Oil Equivalent		
Factors	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBoe)	Gross Probable (MBoe)	Gross Proved Plus Probable (MBoe)	Gross Proved (MBoe)	Gross Probable (MBoe)	Gross Proved Plus Probable (MBoe)
Dec 31, 2020 (1)	12,039	6,495	18,534	691	613	1,303	30,041	13,837	43,878	254	80	334	482	213	696	18,261	9,641	27,902
Extensions	204	145	348	515	383	898	2,254	1,251	3,505	—	—	—	3	2	5	1,098	738	1,836
Infill Drilling	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Improved Recovery	326	92	419	—	—	—	331	150	481	—	—	—	5	2	8	387	120	507
Technical Revisions	361	(630)	(269)	(332)	(489)	(821)	760	272	1,032	63	(12)	50	44	25	68	210	(1,051)	(841)
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	2	—	3	—	—	—	1	—	1	—	—	—	—	—	—	3	—	3
Dispositions	—	—	—	—	—	—	(111)	(42)	(152)	—	—	—	(2)	(1)	(2)	(20)	(8)	(28)
Economic Factors	1,254	(49)	1,205	10	5	15	2,862	286	3,148	26	7	33	47	4	51	1,793	8	1,801
Production (3)	(860)	—	(860)	(107)	—	(107)	(3,195)	—	(3,195)	(44)	—	(44)	(49)	—	(49)	(1,556)	—	(1,556)
Dec 31, 2021 (2)	13,327	6,053	19,379	778	511	1,289	32,943	15,755	48,698	299	75	374	531	246	777	20,176	9,448	29,624

Notes:

(1) Opening balances based on an evaluation report prepared by Sproule dated January 17, 2022 and effective as of December 31, 2021.

(2) Columns may not add due to rounding.

Year-over-year changes in the Company's estimated gross reserves from December 31, 2020 to December 31, 2021 are primarily the result of: (i) new future development reserves bookings in the Princess area (extensions); (ii) additional waterflood reserves recognized in Evi and Michichi (improved recovery); (iii) improved well performance resulting in positive technical revisions, which were offset through undeveloped location removals as a result of mineral expiries (technical revisions); (iv) minor acquisition of third party working interest in Provost (acquisition); (v) minor disposition in Other (disposition); and (vi) changes in the Sproule commodity price forecast (economic factors).

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are assigned by Sproule in accordance with standards and procedures contained in the COGE Handbook. 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. Generally, proved undeveloped reserves are those reserves related to drilling wells or very near producing pools or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Generally probable undeveloped reserves are those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This category also includes probable reserves assigned to proved undeveloped locations.

The following tables set forth, for each product type identified, the volumes of proved undeveloped reserves and probable undeveloped reserves, respectively, attributed to the Company's properties in each of the financial years ended December 31, 2021, 2020 and 2019 and, in the aggregate, before that time, based on forecast prices and costs.

Proved Undeveloped Reserves

	Light & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBoe)	
Year	First Attributed (1)	Total at Year End	First Attributed (1)	Total at Year End	First Attributed (1)	Total at Year End	First Attributed (1)	Total at Year End	First Attributed (1)	Total at Year End
2019	—	7,910	327	459	722	16,905	—	316	448	11,502
2020	—	6,731	—	445	—	14,627	—	238	—	9,852
2021	203	6,221	304	304	1,788	14,371	3	232	809	9,152

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBoe)	
Year	First Attributed (1)	Total at Year End	First Attributed (1)	Total at Year End	First Attributed (1)	Total at Year End	First Attributed (1)	Total at Year End	First Attributed (1)	Total at Year End
2019	1,072	5,948	338	607	4,540	16,391	69	297	2,236	9,584
2020	—	4,948	160	544	216	10,101	—	152	196	7,328
2021	246	4,271	312	312	1,532	10,978	2	171	816	6,584

Note:

(1) "*First Attributed*" refers to previously unassigned volumes that were attributed to proved undeveloped reserves as at year-end of the corresponding fiscal year.

Once identified, undeveloped reserves are generally scheduled into the Company's development plans. We pace our development programs to optimize the value of undeveloped reserves. This pace is affected by changing economic conditions (due to pricing, and operating or capital costs), changing technical conditions (production performance or new data from wells), changing design parameters (such as using horizontal wells, rather than vertical wells, to develop a field), infrastructure constraints (pipeline or facility limitations), and surface access (landowners, weather, and/or regulatory approval). All of the Company's estimated proved plus probable undeveloped reserves are located in the Evi, Princess and Michichi core areas. The Company currently plans to pursue the development of its proven and probable undeveloped reserves over the next five years through ordinary course capital expenditures. The development of certain probable undeveloped reserves is scheduled to occur after the end of year two to accommodate the Company's development program, which needs to be spread out over several years to optimize capital allocation and facility utilization. The Company may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures, the outcomes of drilling and reservoir evaluations, prevailing commodity prices and a variety of economic factors and conditions. The Company has planned a program for the development of a portion of the undeveloped reserves in 2022, focusing on the Princess and Michichi areas.

Significant Factors or Uncertainties Affecting Reserves Data

Uncertainties are inherent in estimating quantities of reserves, including as a result of many factors that are beyond the Company's control. Subsurface accumulations of crude oil, natural gas and NGLs cannot be precisely measured. Reserves estimation is an inferential science that requires significant judgments based on available geological, geophysical, engineering and economic data as well as forecasts of commodity prices and anticipated costs. The accuracy of any reserves estimate is necessarily a function of available data and its interpretation. Estimates by different engineers can vary, sometimes significantly, and the quantities of crude oil, natural gas and NGLs actually and ultimately recovered will vary from reserves estimates.

As circumstances change and additional data becomes available – whether through the results of drilling, testing and production or other reservoir performance indicators, economic factors such as changes in commodity prices or development and production costs, changes in tax or regulatory regimes, or otherwise – reserves estimates also change. Revisions may be positive or negative.

Other than as discussed herein and the various risks and uncertainties to which participants in the oil and gas industry are exposed generally, the Company has not identified significant economic factors or uncertainties that it expects to affect any particular components of the reserves data disclosed herein. See "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

Prairie Provident will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines, in connection with its operations. The Company budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its oil and gas assets. The overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These ongoing environmental obligations are expected to be funded with internally-generated cash flows, borrowings under its Revolving Facility (defined herein) and, to some extent funding from the government-sponsored site restoration program.

Our method for estimating the amount and timing of future abandonment and reclamation expenditures was created at an operating area level, using Prairie Provident's own internal historical costs when available and historical industry costs where necessary or appropriate. If representative comparisons are not readily available, an estimate is prepared based on regulatory requirements. The provision for site restoration and abandonment is based on current legal and constructive requirements, technology, price levels, and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions, and changes in technology. For more information, see Note 2(d) “Use of Estimates and Judgments” in the Company's annual financial statements for the year ended December 31, 2021, available on Prairie Provident’s website at www.ppr.ca and under its issuer profile on SEDAR at www.sedar.com.

As at December 31, 2021, the Company had 1,463 gross (1,135 net) wells for which it expects to eventually incur abandonment costs, and 2,527 gross (2,003 net) wells for which it expects to eventually incur reclamation costs.

The economic forecasts involved in the reserves estimates herein include abandonment, decommissioning and reclamation costs ("ADR costs") associated with all of our facilities, pipelines and wells including those without reserves and undeveloped reserves locations. In estimating the net present value of future net revenue of total proved and probable reserves as disclosed herein, $44.2 million of ADR costs discounted at 10% ($239.9 million, inflated and undiscounted) has been deducted, of which 34% is attributed to inactive assets.

Future Development Costs

The following table sets forth total future development costs deducted in Sproule's estimation of future net revenue (based on forecast prices and costs) attributable to the reserves categories noted below.

	FUTURE DEVELOPMENT COSTS **Forecast Prices and Costs ($000s) - Undiscounted**	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2022	85,941	102,015
2023	34,904	49,682
2024	42,379	48,778
2025	5,028	11,554
2026	—	6,435
Thereafter	—	55
Total (undiscounted)	168,253	218,520
Total (discounted at 10%)	148,675	190,773

The Company currently expects that the capital required to fund estimated future development costs will be provided from its internally-generated cash flows, borrowings under its Revolving Facility (defined herein), proceeds from non-core asset dispositions, and, if necessary, issuance of equity or debt instruments. Costs of funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenues to some degree depending upon the funding sources utilized. The Company does not, however, anticipate that costs of funding would make the development of any property uneconomic. We may in the future consider alternative sources of financing in light of new or changing circumstances.

Estimates of reserves and future net revenues have been made assuming that each property in respect of which the estimate is made will be developed, without regard to the likely availability to the Company of funding required therefor. There can be no guarantee that such funds will be available or that the Company will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on future cash flows from operations.

Other Oil and Gas Information

Principal Properties

Following is a description of our principal oil and natural gas properties, all of which are located onshore in Canada with close proximity to processing and transportation infrastructure.

With respect to those properties to which reserves were attributed as of December 31, 2021 and were capable of producing but not then producing at such time, approximately 95% of such reserves were attributed to waterflood reserves, approximately 2% were attributed to oil and natural gas wells to be reactivated, and approximately 2% related to recompletions within existing wellbores.

Evi Area (Peace River Arch – Northern Alberta)

The Evi area is located in the Peace River Arch area of northern Alberta, which produces primarily light oil from the Devonian Slave Point, Gilwood and Granite Wash formations. As of December 31, 2021, we had an average working interest of approximately 75% in 61,236 gross (46,075 net) acres in and near the Evi field. This position offers a stable light oil production base with significant opportunity to increase our reserves base through waterflood development. The Company implemented its Evi waterflood pilot project in 2011, and began injecting into seven additional horizontal wells in 2018. There are currently twenty-five injection wells in operation. During year ended December 31, 2021, our Evi properties produced average sales volumes of approximately 1,062 boe per day (97% light oil and NGLs). See "*Additional Information Relating to Reserves Data* **-** *Production History*"**.** The Company believes that it can ultimately enhance production rates and recoveries in the Evi area through further waterflood development, recompletions and infill drilling of its acreage.

Michichi Area (Southeastern Alberta)

The Michichi area is located east of Calgary in Southeastern Alberta. As of December 31, 2021, we have an average working interest of approximately 82% in 208,847 gross (171,268 net) acres. This large land position offers an organic growth platform of medium grade oil and associated natural gas opportunities from both the Lower Cretaceous Mannville formations and the Mississippian Banff formations. During the year ended December 31, 2021, our average sales volumes in the Michichi area were approximately 1,832 boe per day (41% light/medium oil and NGLs). See "*Additional Information Relating to Reserves Data - Production History*". The Company believes that it can systematically continue to increase the area production with continued development and waterflood opportunities.

Princess Area (Southeastern Alberta)

Our Princess properties are located in Southern Alberta, approximately 55 miles northwest of Medicine Hat. As of December 31, 2021, we have an average working interest of approximately 98% in our Princess properties comprising 22,589 gross (22,125 net) acres. The primary zones of interest are the Lithic Glauconite, Detrital and Ellerslie formations. During the three months and year ended December 31, 2021, our Princess properties produced average sales volumes of approximately and 1,138 boe per day (approximately 70% light/medium and heavy oil and NGLs). See "*Additional Information Relating to Reserves Data* **-** *Production History*"**.** The Company believes that it can systematically continue to increase the area production with continued development of these oil plays.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company owned a working interest as of December 31, 2021. A well bore with multiple completions is counted as only one well.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing (1)**		**Producing**		**Non-Producing (1)**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	387	325	578	474	199	136	265	177
British Columbia	—	—	—	—	—	—	7	6
Saskatchewan	—	—	14	4	—	—	12	12
Northwest Territories	—	—	—	—	—	—	1	1
Total	387	325	592	478	199	136	285	196

Note:

(1) Non-producing wells include wells capable of producing, but not producing, at December 31, 2021. Non-producing wells do not include wells that have been abandoned.

Properties With No Attributed Reserves

The following table summarizes undeveloped acreage in which the Company owned a working interest or held an exploration license as of December 31, 2021. Acreage related to royalty, overriding royalty and other similar interests, or related to options to acquire additional leasehold interests, is excluded from this summary.

	Undeveloped Acreage	
	Gross	**Net**
Alberta	116,746	89,958
Saskatchewan	321	140
British Columbia	800	448
Northwest Territories	2,379	1,586
East Coast (offshore)	19,084	343
Total	139,330	92,475

At December 31, 2021, 5,020 acres of our net undeveloped acreage will expire in 2022, if not extended by exploration or production activities.

Undeveloped acres are lands that have not been assigned reserves, and are mineral agreement specific. As of December 31, 2021, the Company did not have any other material work commitments related to its undeveloped acres.

Our land holdings range from discovery areas where tenure is held indefinitely by hydrocarbon test results or production to exploration areas in the early stages of evaluation. The Company regularly reviews the economic viability and ranking of its unproved properties on the basis of commodity pricing, capital availability and allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire and relinquished back to the mineral rights owner.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Prairie Provident does not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves, in any ways that are different from our other properties. Our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes, all of which are beyond our control. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See "*Significant Factors or Uncertainties Affecting Reserves Data – Additional Information Concerning Abandonment and Reclamation Costs*" and "*Risk Factors*".

Forward Contracts

The Company is exposed to market risks from fluctuations in commodity prices, power prices, foreign exchange rates and interest rates in the normal course of operations, and maintains a risk management program to reduce the volatility of revenues, increase the certainty of funds from operations, and protect acquisition and development economics through hedging arrangements. Information regarding the Company's hedging arrangements in effect as of December 31, 2021 is set forth in the notes to our annual financial statements for the financial year then ended, available on the Prairie Provident's website at www.ppr.ca and under its issuer profile on SEDAR at www.sedar.com.

Tax Horizon

We were not required to pay any cash income taxes for the year ended December 31, 2021. Based on current estimates of future taxable income, levels of tax deductible expenditures and available tax pools, the Company does not anticipate any material cash income taxes prior to 2071.

Costs Incurred

The following table summarizes property acquisition costs, exploration costs, and development costs incurred by the Company for the year ended December 31, 2021.

Expenditures	**($000s)**
Property acquisition (disposition) costs (net) – proved properties	(56)
Property acquisition (disposition) costs (net) – unproved properties [1]	456
Exploration Costs [2]	—
Development Costs [3]	13,417
Capitalized G&A and other	829
Total	14,646

Notes:

(1) Includes cost of land acquired and lease rentals on unproved properties.

(2) Includes geological and geophysical costs and drilling and completion costs for exploratory wells.

(3) Includes drilling and completion costs for development wells and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The following table sets forth the number of exploratory wells and development wells completed during the year ended December 31, 2021 in which the Company had an interest, on both a gross and net basis.

	Development (1)		Exploratory (2)	
	Gross	Net	Gross	Net
Oil wells	5.0	5.0	—	—
Dry holes	—	—	—	—
Total	5.0	5.0	—	—

Notes:

(1) "*Development well*" means a well drilled inside the established limits of an oil or gas reservoir or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

(2) "*Exploratory well*" means a well that is not a development well or a service well.

Production Estimates

The following table sets forth the estimated 2022 production volumes reflected in Sproule's estimates of the Company's gross proved reserves, gross probable reserves and gross proved plus probable reserves, respectively, as disclosed in the tables set forth under "*Reserves Data*" above, together with information regarding the portion of those estimated first-year production volumes attributed to our Evi, Michichi and Princess fields.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Total Oil Equivalent (boe/d)
TOTAL PROVED RESERVES						
Evi	1,059	—	208	—	8	1,102
Princess	819	220	2,581	—	4	1,473
Michichi	1,673	—	8,720	82	132	3,272
Other Properties	159	40	11	—	29	230
Total Proved	3,711	260	11,520	82	173	6,078
TOTAL PROBABLE RESERVES						
Evi	36	—	6	—	—	37
Princess	130	15	452	—	1	222
Michichi	871	—	2,515	—	74	1,364
Other Properties	18	13	85	—	(27)	18
Total Probable	1,056	28	3,058	—	48	1,641
TOTAL PROVED PLUS PROBABLE RESERVES						
Evi	1,095	—	214	—	8	1,139
Princess	950	235	3,033	—	5	1,695
Michichi	2,545	—	11,235	82	206	4,637
Other Properties	177	53	96	—	2	248
Total Proved plus Probable	4,767	288	14,578	82	221	7,719

Our Princess and Michichi fields are the only properties that account for 20% or more of the Company's estimated 2022 production as reflected in the Sproule Report.

Production History

The following table summarizes, on a quarterly basis for the year ended December 31, 2021, certain information in respect of our production volumes, product prices received, royalties paid, production (operating) costs incurred and resulting netback (before hedging).

	Quarter Ended			
	March 31, 2021	**June 30, 2021**	**Sept 30, 2021**	**Dec 31, 2021**
Average Daily Production [1]				
Light and Medium Oil (bbls/d)	2,453	2,514	2,261	2,198
Heavy Oil (bbls/d)	117	179	384	492
Conventional Natural Gas (Mcf/d)	8,135	8,998	8,825	9,146
Coal Bed Methane (Mcf/d)	98	124	161	100
NGLs (bbls/d)	129	140	131	138
Combined (boe/d)	4,071	4,354	4,273	4,369
Average Price Received [2]				
Light and Medium Oil ($/bbl)	60.34	71.00	76.12	80.81
Heavy Oil ($/bbl)	51.76	63.72	71.78	79.98
Conventional Natural Gas (Mcf/d)	3.49	2.81	3.70	4.89
Coal Bed Methane (Mcf/d)	3.07	2.72	2.83	4.63
NGLs ($/bbl)	44.79	50.55	59.16	74.35
Combined ($/boe)	46.31	51.13	56.30	62.36
Royalties Paid				
Light and Medium Oil ($/bbl)	4.33	7.39	8.97	10.65
Heavy Oil ($/bbl)	7.56	10.81	11.89	13.74
Conventional Natural Gas (Mcf/d)	0.09	0.37	0.26	0.40
Coal Bed Methane (Mcf/d)	0.39	0.31	0.27	0.52
NGLs ($/bbl)	10.65	12.18	17.36	18.42
Combined ($/boe)	3.34	5.87	6.89	8.32
Production (Operating) Costs [3][4]				
Light and Medium Oil ($/bbl)	28.30	24.82	27.14	28.68
Heavy Oil ($/bbl)	36.84	21.17	18.64	19.31
Conventional Natural Gas (Mcf/d)	3.94	3.43	4.25	3.71
Coal Bed Methane (Mcf/d)	1.50	1.19	1.74	1.62
NGLs ($/bbl)	24.51	23.84	26.84	24.40
Combined ($/boe)	26.80	23.10	25.69	25.18
Netback Received[5]				
Light and Medium Oil ($/bbl)	27.71	38.79	40.01	41.48
Heavy Oil ($/bbl)	7.36	31.74	41.25	46.93
Conventional Natural Gas (Mcf/d)	(0.54)	(0.99)	(0.81)	0.78
Coal Bed Methane (Mcf/d)	1.18	1.22	0.82	2.49
NGLs ($/bbl)	9.63	14.53	14.96	31.53
Combined ($/boe)	16.17	22.16	23.72	28.86

Notes:

(1) Before deduction of royalties.

(2) Not including any realized losses/gains on the Company's forward contracts on oil and natural gas.

(3) Operating costs are composed of direct costs incurred to operate both oil and natural gas wells. A number of assumptions are required to allocate these costs between product types.

(4) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.

(5) Netbacks are calculated by subtracting royalties and production (operating) costs from revenues. Realized losses/gains on the Company's forward contracts on oil and natural gas are not considered in the calculation of netbacks.

The following table indicates our average daily net production volumes (by product type) from the Company's important fields for the year ended December 31, 2021.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Total Oil Equivalent (boe/d)
Evi	1,018	—	212	—	9	1,062
Princess	537	255	2,060	—	3	1,138
Michichi	639	—	6,346	98	119	1,832
Other Properties	161	39	161	23	5	236
Total	2,355	294	8,779	121	136	4,268

INDUSTRY CONDITIONS

The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and our oil and gas operations are subject to federal, provincial, territorial and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation and disposal of oil and gas, oil and gas by-products and other substances and materials produced or used in connection with oil and gas operations. More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling and completion of wells, the method and ability to produce from wells, surface usage, transportation of production, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in administrative, civil and criminal penalties, remedial obligations, loss or cancellation of governmental or regulatory approvals and injunctions or similar orders that could delay, limit or prohibit certain of our operations. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil, natural gas and natural gas liquids that may be removed from the provinces and exported from Canada in certain circumstances. In order to conserve supplies of oil and natural gas, these agencies may also restrict the rates of flow of oil and natural gas wells below actual production capacity. Further, a significant spill from one of our facilities could have a material adverse effect on our results, operations, competitive position or financial condition.

We do not expect that any of these regulatory controls and restrictions will affect our operations in a manner significantly different than they would affect other oil and gas companies of similar size. All current laws and regulations are a matter of public record and the Company is unable to predict what additional laws, regulations or amendments may be enacted.

Pricing and Marketing in Canada

Crude Oil

Oil producers negotiate sales contracts directly with purchasers, resulting in a market-determined price of oil. Worldwide supply and demand factors are the primary determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply and demand balance and contractual terms of sale.

Beginning in early 2020, worldwide oversupply of oil, a lack of available storage capacity and decreased demand due to COVID-19 had a significant impact on the price of oil. In an effort to stabilize global oil markets, the Organization of the Petroleum Exporting Countries ("**OPEC**") and a number of other oil producing countries announced an agreement to cut oil production by approximately 10 million bbls/d in April 2020, which was amended and adjusted throughout 2020 and early 2021. This agreement contributed to rebalancing global oil markets by achieving approximately 99.5% compliance with the agreed production adjustment commitments. The oil and gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. In mid-2021, OPEC agreed to gradually reinstate crude oil production levels during the remainder of 2021 and in 2022.

Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tensions in Eastern Europe. In February 2022, Russia launched a large scale invasion of Ukraine. Ongoing military conflict between Russia and Ukraine has the potential to threaten the supply of oil and gas from the region. The long-term impacts of the conflict between these nations remains uncertain.

Natural Gas

Negotiations between buyers and sellers determine 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 and demand balance and other contractual terms of sale.

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 negotiations between buyers and sellers. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. 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 of sale.

Transportation Capacity, Curtailment and Market Access

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and long-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "**CERA**"). 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. Prairie Provident does not directly enter into contracts to export its production outside of Canada.

Canada's overall pipeline capacity and ability to access the United States and other international markets is constrained. The transportation capacity deficit is not likely to be resolved quickly. In addition, major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other conditions have been satisfied. As further outlined below, although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory obstacles, litigation, economic and other sociopolitical factors. Due in part to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets over the last several years. The commissioning of Enbridge's Line 3 Replacement in the second half of 2021 has improved Western Canadian pricing. Other new pipelines are in development, and if completed, will help to further alleviate Canada's transportation capacity limitations and improve access to global markets.

Crude Oil by Rail

Transportation of crude oil by rail, as an alternative to pipelines, has increased significantly in recent years. Various regulatory and policy initiatives have followed, including in response to derailment incidents.

In May 2015, *Regulations Amending the Transportation of Dangerous Goods Regulations (TC 117 Tank Cars)*, made pursuant to the *Transportation of Dangerous Goods Act, 1992*, came into force to require that certain types of tank cars be phased out for crude oil and other flammable liquids by April 2025. In September 2018, timelines were accelerated by Transport Canada to November 1, 2018 for affected tank cars that transport crude oil and to January 1, 2019 for affected tank cars that carry condensates. The *Transportation of Dangerous Goods by Rail Security Regulations* were made under the *Transportation of Dangerous Goods Act, 1992* in May 2019 with the stated aim of mitigating the security risks of transporting dangerous goods by rail. Various requirements thereunder came into force between June 2019 and May 2020.

Since 2020, trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, have also been subject to reduced speed limits within metropolitan areas, as well as mandatory speed reductions applying outside of metropolitan areas during winter months (November 15 to March 15).

These and other policy and regulatory developments could restrict access to rail transportation and/or increase the cost thereof.

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier crude oil pipeline system. A common carrier pipeline must accept all products offered to it for transportation. If there is insufficient capacity to transport the volumes offered, the available capacity is pro-rated to accommodate all shippers. The changes that Enbridge sought to implement in the open season included the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers would have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. Had the service change been approved, shippers seeking firm capacity on the Enbridge system would no longer have been able to rely on the nomination process and would have had 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 first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided in September 2019 to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service. In December 2019, Enbridge applied to the CER for approval of its proposed service and tolling framework. In November 2021, the CER denied Enbridge's application to implement firm service contracting on the mainline system, on the basis that it did not comply with the common carriage requirements under section 239(1) of the CERA.

Recent Developments Concerning Proposed Pipeline Projects

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the Federal Government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. However, there is ongoing opposition and construction is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route of the pipeline. A new project timeline is pending, and it is unknown whether the expected in-service date of December 2022 will be affected.

On March 31, 2020, TC Energy Corporation ("**TC Energy**") announced it would proceed with the Keystone XL Pipeline. On January 20, 2021, Joe Biden was sworn in as President of the United States, following which the Biden administration announced its decision to revoke the presidential permit to permit the Keystone XL Pipeline to operate across the international border. As a result of the revocation, on June 9, 2021, TC Energy terminated the Keystone XL Pipeline project.

The Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin came into service in October 2021 and is expected to transport 760,000 bbl/d at full capacity.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, potentially forcing the lines comprising this segment of the pipeline system to be shut down. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. On October 4, 2021, the Government of Canada invoked a 1977 treaty with the United States, triggering bilateral negotiations over the pipeline. On December 15, 2021, Enbridge moved to transfer the Attorney General's lawsuit from Michigan State Court to United States Federal Court.

Natural Gas and LNG

Natural gas prices in Western Canada have 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 infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed relative to other markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline system (the "**NGTL System**") to prioritize deliveries into storage. The change stabilized supply and pricing, particularly during periods of maintenance on the system. An expansion to the NGTL System was recommended for approval by the CER and sent to the Federal Cabinet for approval. Following an extended timeline for consultation with Indigenous groups, the Federal Cabinet on April 30, 2021 approved the issuance of the certificate of public convenience by the CER.

In July 2020, the Explorers and Producers Association of Canada applied to extend the temporary service protocol, which was opposed by NGTL and ultimately denied by the CER in February 2021.

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition, and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

Despite receiving all necessary governmental and regulatory approvals, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is currently proceeding. The CGL Pipeline is currently 50% completed and is slated to be completed in 2023.

In addition to the LNG Canada and CGL Pipeline projects, various other LNG projects have been proposed in Canada.

Curtailment

On December 2, 2018 the Government of Alberta announced that, commencing January 1, 2019, it would mandate a reduction in provincial crude oil and crude bitumen production. Such announcement was implemented by an Order in Council issued on December 3, 2018 approving Alta Reg 214/2018 (the "**Curtailment Rules**"). Under the Curtailment Rules, the Government of Alberta, on a monthly basis, directed oil producers producing more than 20,000 bbl/d to curtail their production according to a pre-determined formula that apportioned production limits proportionately amongst those operators subject to a curtailment order.

The Curtailment Rules, which were set to be repealed on December 31, 2020, were extended until December 31, 2021 giving the Alberta Minister of Energy the regulatory authority to curtail future production if needed. On December 9, 2021, the Government of Alberta announced that the provincial policy on restraining oil production, a strategy to reduce price-depressing gluts, would end December 31, 2021.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement between Canada and the European Union, the Canada-United Kingdom Trade Continuity Agreement, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the Canada-United States-Mexico Agreement (the "**CUSMA**"), which came into force on July 1, 2020, replacing the North American Free Trade Agreement ("**NAFTA**"). Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the CUSMA could have an impact on Western Canada's oil and gas industry at large, including our business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the CUSMA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia and Europe. Additionally, the CUSMA deleted a technical issue related to diluents that previously added upwards of $60 million a year in duties and other fees. The new agreement allows up to 40% of non-originating diluent in pipelines, fixing this cost issue.

Land Tenure

With the exception of Manitoba, where the majority of oil and gas rights are held privately, provincial governments in Western Canada own most of the mineral rights to the oil and natural gas located within their respective provincial borders. Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses and permits and regulations as issued by the applicable governments. Lease terms vary in length, but usually range from two to five years. Other terms and conditions to maintain a mineral lease are set out in the relevant legislation or are negotiated.

Continuing interests in petroleum and natural gas licenses are earned by the drilling of a well. A lease is proven productive at the end of its initial term by drilling, producing, mapping, being part of a unit agreement or by paying offset compensation. If a lease is proven productive, it will continue indefinitely beyond its initial term. The tenure only comes to an end when the holder can no longer prove its well is capable of producing oil or gas.

Many jurisdictions in Canada, including Alberta and British Columbia, have legislation in place for mineral rights reversion to the Crown of stratigraphic formations that cannot be shown to be capable of production at the end of the primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for non-productive lands, having met certain criteria as laid out in the relevant legislation.

Certain oil and natural gas mineral interests are privately owned. Rights to explore for and produce on such lands are granted by leases on such terms and conditions as may be negotiated between the landowner and the lessee.

Royalties

General

Each of the provinces and territories in which the Company operates has legislation and regulations governing royalties, land tenure, production rates and taxes, environmental protection and other matters under their respective jurisdictions. The royalty regime applicable in such jurisdictions is a significant factor in the profitability of our production. Crown royalties payable in respect of production from Crown, or public, lands are determined by government regulation and are generally calculated as a percentage of the gross production value. The production value and royalty rates generally depend on prescribed reference prices, well productivity, geographical location, field discovery date and the type of product produced.

Royalties payable on production from lands other than Crown lands, also known as freehold lands, are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Any such royalties (or royalty-like interests) are carved out of the working interest owner's interest through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

Provincial governments from time to time adopt incentive programs designed to encourage oil and gas exploration and development activity and improve earnings and cash flow within the energy industry. These programs may include royalty rate reductions, drilling credits, royalty holidays or royalty tax credits. Such programs are often of limited duration and target specified oil and gas activities.

Alberta

All the Company's current oil and gas production is from properties located in Alberta.

Modernized Royalty Framework

Royalties are important to the Alberta government's revenue stream. On January 1, 2017, Alberta implemented a new royalty framework (the "**Modernized Framework**"). The Modernized Framework applies to all wells spud on or after January 1, 2017, while wells spud prior to July 13, 2016 will continue to operate under the old royalty framework (the "**Old Framework**") for a period of 10 years ending December 31, 2026. After the expiry of this 10-year period, these older wells will become subject to the Modernized Framework. Owners of wells spud between July 13, 2016 and December 31, 2016 were given the option to opt-in early to the Modernized Framework if certain criteria were met. Owners of wells spud between July 13, 2016 and December 31, 2016 that did not elect to opt-in early to the Modernized Framework or did not meet the criteria will continue to operate under the Old Framework until December 31, 2026.

Under the Modernized Framework, royalties are determined on a "revenue-minus-costs" basis, with the cost component based on a drilling and completion cost allowance formula for each well, which is dependent on its vertical depth and horizontal length. The cost component attempts to incentivize innovation to reduce costs by allowing wells that are drilled and completed for less than the industry average cost to remain at a lower royalty rate even after recovering actual costs. Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative revenues from the well equals the drilling and completion cost allowance for the well set by the Alberta Energy Regulator (the "**AER**"). After payout, producers pay an increased royalty on net revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, the royalty rate will be adjusted downward to a minimum of 5% as the mature well's production declines.

In connection with the implementation of the Modernized Framework, the Government of Alberta also announced two new strategic royalty programs to encourage oil and gas producers to maximize production and explore resources in new areas: the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs take into account the higher costs associated with developing emerging resources and enhanced recovery methods when calculating royalty rates.

1. Emerging Resources Program

The Emerging Resources Program began January 1, 2017 and is meant to encourage industry to pursue new oil and gas resources in higher-risk and higher-cost areas with large resource potential. To be eligible, the Minister of Energy must determine that certain criteria are met.

Eligible wells pay a flat royalty rate of 5% until their combined revenue equals their drilling and completion cost. Unlike the Modernized Framework, the drilling and completion cost calculation includes a multiplier that ranges from 1.5 to 2.0 set at the time of project approval. The multiplier is based on the level of existing drilling activity at the time of application and it declines over time. The benefit period may last for up to 10 years from a project's start date and for an additional 5 years afterwards, to use the remains of the pooled program-specific cost allowance. After the benefit period ends, wells in the scheme will be subject to normal royalty rates under the Modernized Framework.

2. Enhanced Hydrocarbon Recovery Program

The Enhanced Hydrocarbon Recovery Program began January 1, 2017 and replaces the Enhanced Oil Recovery Program under the Old Framework. Approved schemes target tertiary recovery methods involving the injection of materials into a reservoir to increase hydrocarbon production and secondary recovery methods involving the injection of water or gas into a reservoir to increase hydrocarbon production.

Eligible wells are subject to a flat 5% royalty for a prescribed benefit period, up to a maximum of 90 months. After December 31, 2026, wells in the scheme will be subject to regular royalty rates under the Modernized Framework.

<u>Old Framework</u>

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017, as well as certain bitumen production. Subject to certain available incentives, and effective from the January 2011 production month, royalty rates for conventional oil production under the Old Framework range from a base rate of 0% to a cap of 40%.

The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres, as well as the acid gas content of the produced gas. Subject to certain available incentives, and effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%.

Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

<u>Royalty Rates</u>

The Government of Alberta passed the *Royalty Guarantee Act* on July 18, 2019, ensuring that when a well is drilled, the royalty structure will remain in place for at least ten years, subject to certain listed exceptions. On July 23, 2020, the *Red Tape Reduction Implementation Act*, received Royal Assent. The *Red Tape Reduction Implementation Act* amends the *Mines and Minerals Act* (Alberta), allowing the Alberta Minister of Energy to make changes to royalty rates without Cabinet's approval. There can be no assurances that the Government of Alberta will not amend or repeal these Acts, or that the Government of Canada will not adopt new royalty regimes, which may render the

Company's projects uneconomic or otherwise adversely affect its results of operations, financial condition or prospects.

Taxes on Freehold Production

Taxes are payable to the Province of Alberta in respect of oil and natural gas production obtained from lands other than Crown lands. The tax levied in respect of freehold oil and gas production in Alberta is calculated annually. The formula accounts for the amount of production, the hours of production, unit value, the tax rate, the percentages that the owners hold in the title and the percentages that the title and well hold in the production entities being taxed.

British Columbia

Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. The royalty rate for oil can be as high as 40% and as high as 27% for natural gas.

On October 7, 2021, the Government of British Columbia launched a comprehensive review of its oil and gas royalty system. Based on the outcomes of the review and input received from the public, a policy announcement is expected in 2022.

Environmental Regulation

All phases of the oil and gas business present environmental risks and are subject to environmental regulation under international conventions and national, provincial, territorial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges and emissions of various substances produced or used in association with oil and gas operations, as well as requirements for oilfield waste handling, storage and disposal, land reclamation, habitat protection, and minimum setbacks of oil and gas activities from surface water bodies.

As an operator of oil and natural gas properties in Canada, the Company is subject to stringent federal, provincial, territorial and local laws relating to environmental protection and abandonment and reclamation. Compliance with these laws can affect the location or size of wells and facilities, the extent of exploration and development, and the abandonment of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial obligations, and the incurrence of capital or increased operating costs relating to compliance and injunctions that limit or prohibit activities.

We have established internal guidelines to comply with environmental laws in the jurisdictions in which we operate. We employ an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental, health and safety laws. Although we maintain pollution insurance against the costs of clean-up operations, public liability, and physical damage, there is no guarantee that such insurance will cover all such costs.

Federal

Federal environmental legislation may apply to various aspects of oil and gas projects. Current Federal environmental legislation includes, among other sources, the *Impact Assessment Act,* the *Canadian Environmental Protection Act, 1999* and the *Canadian Navigable Waters Act.* Additionally, projects may be subject to the *Fisheries Act*, which prohibits the deposit of deleterious substances or the carrying on of work that could result in serious harm to fish, the *Species at Risk Act*, which protects critical habitats for species of concern, and the *Migratory Birds Convention Act*, which protects migratory birds, their eggs, and their nests from destruction, each of which may limit the Company's development.

The *Impact Assessment Act* came into force in August 2019 and replaced the *Canadian Environmental Assessment Act, 2012*. It established the Impact Assessment Agency of Canada, which leads and coordinates impact assessments for all designated projects, including those previously administered by the National Energy Board. The *Impact Assessment Act* applies to designated projects listed in the *Physical Activities Regulations* and physical activities designated by the Minister of Environment and Climate Change Canada on an *ad hoc* basis. The legislation expanded the assessment considerations beyond the environment to expressly include health, economic, social and gender impacts, as well as considerations related to sustainability and Canada's climate change commitments. The *CERA* also came into force in August 2019, replacing the National Energy Board with the CER and modifying the CER's role in federal impact assessments.

Designated projects under the *Impact Assessment Act* include fossil fuel-fired power generating facilities over a certain production capacity, new in situ oil sands extraction facilities over a certain bitumen production capacity, offshore production platforms and natural gas liquids storage facilities over a certain storage capacity. The *Impact Assessment Act* provides a time limit for report finalization being 300 days after the day on which the Impact Assessment Agency of Canada posts notice that they are satisfied with the proponent's submissions. For designated projects, the Impact Assessment Agency of Canada may establish a longer time limit to cooperate with jurisdictional requirements or to take into account specific project circumstances. The Impact Assessment Agency of Canada may also establish a shorter time limit for any reason it considers appropriate.

The Government of Alberta submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the *Impact Assessment Act*. The case was heard in 2021 but a decision has not been issued and the matter remains before the Court of Appeal.

Amendments to the *Navigation Protection Act* that came into force in August 2019 renamed the statute as the *Canadian Navigable Waters Act*, expanded its scope to all navigable waters, created greater oversight for navigable waters and, consistent with the Fisheries Act, introduced requirements to expand the scope of protection and the role of Indigenous groups and interests. The broader application of the Canadian Navigable Waters Act may result in increased permitting requirements where the Company's operations potentially impact navigable waters.

Amendments to the *Fisheries Act* in 2019 restored the prohibition against harmful alteration, disruption or destruction of fish habitats, and the prohibition against causing the death of fish by means other than fishing. The amendments also introduced several new requirements to expand the scope of protection and role of Indigenous groups and interests. The prohibitions against the death of fish, and the harmful alteration, disruption or destruction of fish habitats may result in increased permitting requirements where the Company's operations potentially impact fish or fish habitats.

The *Pipeline Safety Act*, which came into force in June 2016, amended the *National Energy Board Act* and the *Canada Oil and Gas Operations Act* to strengthen the safety and security of pipelines. The *Pipeline Safety Act* reinforces the "polluter pays" principle, so that operators of pipelines are liable for costs and damages of all unintended or uncontrolled releases of oil, gas or other substances. Canada was the first country to introduce absolute liability irrespective of fault, with liability in amounts up to $1 billion for major pipelines (i.e., those with transport capacity over 250,000 bbls/d) or otherwise, as prescribed by regulation for pipelines with lower capacity. In instances involving fault or negligence, liability is unlimited. Operators must maintain the financial resources necessary to meet the applicable absolute liability obligations imposed under the *Pipeline Safety Act*.

If a company is unable or unwilling to respond to, or clean up releases from a pipeline, the CER has the authority to take control of that pipeline release. There is a three-year period from the day damage or costs are incurred to bring claims against pipeline operators who are at fault for a pipeline release. Claims cannot be made beyond six years after the release occurred. These claims are adjudicated by a tribunal established by the *Pipeline Safety Act*.

The *Pipeline Safety Act* authorizes the CER to impose stringent requirements for abandoned pipelines, including an obligation to maintain adequate funds to pay for abandonment costs.

Alberta

The AER is the principal regulator responsible for all energy development in Alberta. The mandate of the AER is to ensure the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment.

The *Environmental Protection and Enhancement Act* and the *Oil and Gas Conservation Act* are key pieces of environmental legislation in Alberta. Under the *Environmental Protection and Enhancement Act*, certain oil and activities involving substance release and reclamation may require approval from the AER or Alberta Environment and Parks, and certain activities may require an environmental impact assessment to be carried out. The *Oil and Gas Conservation Act* establishes a regulatory regime and scheme of approvals for the development of oil and gas resources and related facilities.

We currently operate or lease, and have in the past operated or leased, a number of properties that have been used for the exploration and production of oil and gas. Although we utilize and have utilized standard industry operating and disposal practices, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed wastes or remediate property contamination, or to perform well plugging, pit closure or other actions of a remedial nature to prevent future contamination.

The Company may be affected by Alberta's frameworks for air quality, surface water quality and groundwater, under which parties may be required to comply with environmental limits and participate in regional monitoring. These frameworks are created under the *Alberta Land Stewardship Act* as legislative instruments equivalent to regulations.

The AER has issued several directives related to environmental protection, including directives relating to groundwater protection in hydraulic fracturing operations. AER Directive 083: *Hydraulic Fracturing - Subsurface Integrity* mandates licensees demonstrate that operational risks have been considered in the selection and design of the wellbore construction, and that licensees monitor and test to ensure that well integrity is maintained. It also requires licensees to conduct a risk assessment if hydraulic fracturing operations will be conducted above or within 100 metres below the base of groundwater protection. AER Directive 059: *Well Drilling and Completion Data Filing Requirements* requires disclosure of hydraulic fracturing fluid composition and water source data on a well-to-well basis within 30 calendar days from conclusion of an operation. In addition, due to seismic activity reported in some active oil and gas areas of Alberta, the AER has implemented seismic monitoring and reporting requirements for hydraulic fracturing operators in the certain zones in such areas.

The operations of the Company are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. It is impossible to predict the full impact of these laws and regulations on the Company's operations. However, it is not anticipated that the Company's competitive position will be adversely affected by current or future environmental laws and regulations governing its current operations. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to environmental protection.

We believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While we believe that we are in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on us, we cannot give any assurance that we will not be adversely affected in the future.

British Columbia

Environmental regulations in British Columbia are, for the most part, set out in the *Environmental Management Act* ("**BCEMA**") and the *Oil and Gas Activities Act* ("**OGAA**"). The OGAA regulates the storage, discharge and disposal of air contaminants, effluent and hazardous waste into the environment. The BCEMA provides for, among other things, the remediation of contaminated sites and for the imposition of significant penalties in the event of non-compliance.

The British Columbia Oil and Gas Commission (the "**BCOGC**") is the provincial regulatory agency responsible for overseeing oil and gas operations in British Columbia, including exploration, development, pipeline transportation and reclamation. The BCOGC regulates all oil and gas activities under the OGAA, including shale and tight resources development activities.

The OGAA was enacted in 2010 to focus on effective oversight of oil and gas development while protecting public safety and the environment. Associated regulations under the Act include the *Drilling and Production Regulation*, *Pipeline Regulation*, *Environmental Protection and Management Regulation* and *Dormancy and Shutdown Regulation*. These regulations apply to both conventional and unconventional development. The *Dormancy and Shutdown Regulation* came into force in May 2019, and allows the BCOGC to order the decommissioning and reclamation of “dormant” wells.

The *Environmental Protection and Management Regulation* established British Columbia's environmental objectives for water, riparian habitats, wildlife and wildlife habitats, old-growth forests and cultural heritage resources. The OGAA requires the BCOGC to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. The *Petroleum and Natural Gas Act* (British Columbia), in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work.

British Columbia also requires mandatory public disclosure of hydraulic fracturing fluid ingredients under the *Drilling and Production Regulation* and has an online registry providing public access to information on fractured well locations and hydraulic fracturing fluid ingredients.

In November 2018, British Columbia passed Bill 51: *Environmental Assessment Act* which sets out new framework legislation for the *Environmental Assessment Act*. The changes to British Columbia's environmental assessment process are intended to enhance public confidence, advance reconciliation with Indigenous nations and protect the environment while offering a clear pathway to sustainable project approvals. The new framework legislation came into force on December 16, 2019. Leading up to the legislation coming into force, there was a public consultation period for policy development and regulations relating to core elements of the framework.

The *Environmental Assessment Act* creates an early engagement process and increases public participation in environmental assessments for resource projects. It also requires the Environmental Assessment Office ("**EAO**") to seek to achieve consensus with Indigenous nations at various stages of the assessment process. Indigenous nations will also have an opportunity at two decision points to indicate whether the nation consents to a proposed EAO decision: (i) whether to exempt a project from the assessment process or terminate the assessment process for a project; and (ii) whether an Environmental Assessment Certificate should be issued. If consent is not secured, the *Environmental Assessment Act* sets out a codified dispute resolution process.

Projects that fall within certain categories must submit a notification to the EAO, even if its parameters are within prescribed thresholds. The Minister then determines whether the project is a reviewable project. The *Environmental Assessment Act* provides specific considerations for the Minister when determining whether to designate a project. Once the project is designated as reviewable, the new early engagement process will begin. The early engagement process, increased public participation opportunities and the requirement to seek to achieve consensus with Indigenous nations raise potential concerns surrounding increased timelines for assessments. The Ministry expects timelines to be shorter because of increased consultation at the start of projects, but the practical implications of this change remain to be seen.

On November 26, 2019, British Columbia passed Bill 41, draft legislation to implement the United Nations Declaration on the Rights of Indigenous Peoples ("**UNDRIP**"), becoming the first Canadian province to do so. UNDRIP consists of 46 articles that offer guidance to governments on recognizing and promoting rights of Indigenous people around the world. The most debated principles relate to obtaining the free, prior and informed consent of Indigenous communities before taking actions or approving projects affecting Indigenous land or resources. Although the Province retains authority for making decisions in the public interest and the legislation does not provide for the ability to veto decisions on resource projects, it could nonetheless give litigious First Nations an opportunity to tie up regulatory processes.

In 2019, the British Columbia government submitted a constitutional reference to the British Columbia Court of Appeal regarding its ability to amend the *Environmental Management Act*. The amendments would introduce the concept of hazardous substance permits to regulate heavy oil and interprovincial pipelines. On May 24, 2019 the British Columbia Court of Appeal unanimously ruled that it is beyond the jurisdiction of the Government of British Columbia to enact the proposed amendments to the *Environmental Management Act*. The court held that the proposed amendments were aimed at regulating interprovincial pipelines, which are under federal jurisdiction. Despite the unanimous decision, British Columbia's Attorney General appealed the decision to the Supreme Court of Canada ("**SCC**"). The appeal was dismissed by the SCC on January 16, 2020.

Northwest Territories

Environmental legislation in the Northwest Territories is, for the most part, set out in the territorial *Environmental Protection Act* and *Oil and Gas Operations Act*, the federal *Northwest Territories Act* (Canada) and their associated regulations. In 2018, the Government of the Northwest Territories released its *Petroleum Resources Strategy*, which sets out ten goals under three pillars for developing the economic potential of the Northwest Territories' petroleum resources. The goals are identified as short-, medium-, and long-term.

In June 2021, the Northwest Territories' Department of Industry, Tourism and Investment ("**ITI**") released its Oil & Gas Annual Report for the year ending December 31, 2020. The report states the ITI is assessing the actions in the *Petroleum Resources Strategy* implementation plan and performance measurement framework. During 2020, the ITI continued collecting *Petroleum Resources Strategy* implementation data from various government departments and industry partners to evaluate the implementation of the *Petroleum Resources Strategy*. Further updates on the implementation of the *Petroleum Resources Strategy* may be available when the ITI releases its Oil & Gas Annual Report for the year ending December 31, 2021.

Environmental Legislation Overall

Environmental 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, or in the suspension or revocation of necessary licenses and approvals. The Company may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject the Company to statutory strict liability in the event of an accidental spill or discharge from a facility, meaning that fault on our part need not be established if such a spill or discharge is found to have occurred.

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 third parties and may require the Company to incur costs to remedy such a discharge in an event not covered by our insurance, which insurance is in line with industry practice. Furthermore, we expect incremental future costs associated with compliance with increasingly complex environmental protection requirements with respect to greenhouse gas ("**GHG**") emissions or otherwise, some of which may require the installation of emissions monitoring and measuring devices, the verification and reporting of emissions data and additional financial expenditures to comply with GHG emissions reduction requirements.

Liability Management Rating Programs

Alberta

The AER implements the Licensee Liability Rating ("**LLR**") program, a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Oil and Gas Conservation Act* established an Orphan Well Fund (the "**Orphan Well Fund**"), managed by the industry-funded OWA, 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 becomes defunct. The Orphan Well Fund is funded by licensees in the LLR program through a levy administered by the AER, based on their proportionate share of deemed abandonment and reclamation liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta. British Columbia has a similar liability management regime. In 2020, given the increase in orphaned oil and natural gas assets, the Government of Alberta loaned the Orphan Well Fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Well Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licenses subject to the Large Facility Liability Management Program ("LFP"). Collectively, these programs are designed to minimize the risk to the Orphan Well Fund posed by licensees' unfunded liabilities and to prevent taxpayers in 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 for each licensee and failure to post the required security deposit may result in enforcement action by the AER.

The AER also employs liability management programs through the LFP, as described in Directive 024*: Large Facility Liability Management Program* and the Oilfield Waste Liability Program, as described in Directive 075*: Oilfield Waste Liability (OWL) Program.*

To address abandonment and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. The AER created an Inactive Well Compliance Program intended to address the growing inventory of inactive and noncompliant wells in Alberta and a voluntary area-based closure ("ABC") program. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The Company is participating in the voluntary ABC program.

Additionally, the Government of Alberta announced in July 2020 that the new Liability Management Framework ("**AB LMF**") will replace the Alberta Liability Management Rating ("**AB LMR**") Program and its constituent programs. The intention behind the new framework is to create clear rules with respect to the management of oil and gas liabilities in order to accelerate the responsible reclamation of oil and gas sites in support of a cleaner environment, and to improve Alberta's overall competitiveness in attracting future oil and gas investment. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LMR Program and establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of oil and gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require mandatory annual minimum payment towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

The Government of Alberta followed the announcement of the AB LMF with amendments to the Oil and Gas Conservation Rules and the Pipeline Rules in December 2020. The changes to these rules fall into three broad categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

On April 7, 2021, the AER released a revised edition of Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* to implement some of these changes. The changes build on the AER's corporate and financial disclosure requirements for parties who wish to acquire, hold or transfer licenses in Alberta, and broadening the AER's discretion to withhold or revoke licensees' privileges if they are assessed as posing an "unreasonable risk". See "*Industry Conditions – Liability Management Rating Programs – Redwater Decisions*" below for more information about Directive 067 and revisions thereto.

Redwater Decisions

On January 31, 2019, the SCC released its decision in the case of *Orphan Well Association v Grant Thornton Ltd.* ("**Redwater**"). Reversing the decisions of the Alberta Court of Queen's Bench and Alberta Court of Appeal, the SCC held that trustees and receivers of insolvent parties cannot disclaim or renounce uneconomic oil and gas assets to the AER before commencing the sales process for an insolvent party's assets. Following this ruling, license holders (including a receiver or trustee) that become insolvent will generally be required to apply the value of any remaining assets to satisfy the liabilities associated with their abandonment and reclamation obligations in priority to the claims of secured and unsecured creditors.

On June 20, 2016, as part of its response to the Redwater trial decision, the AER released Bulletin 2016-16: Licensee Eligibility - Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision ("**Bulletin 2016-16**") that implemented three important changes to the LLR program and the related regulatory regime, which were effective immediately.

The first change involved the consideration and processing of applications for licence eligibility under Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals. This change was codified in an amendment to Directive 067 in December 2017, giving the AER broad discretion to determine whether a party poses an "unreasonable risk" such that it should not be eligible to hold AER licences and companies now must provide more financial information to the AER.

The AER assesses risk using financial, behavioural, and inventory factors to identify companies that may be unable to meet their financial responsibilities.

The second change involved holders of existing, but previously unused, licence eligibility approvals. Before approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers and/or shareholders are substantially the same as when licence eligibility was originally granted.

Finally, as a condition of transferring existing AER licences, approvals, and permits, the AER requires all transferees to demonstrate that they have a liability management rating of 2.0 or higher immediately following the transfer. The AER calculates liability management rating as a ratio of a company's deemed assets (production) to its deemed liabilities (abandonment and reclamation costs).

The Government of Alberta has since introduced several legislative changes with respect to the province's regulation of oil and gas liabilities. The AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs.

On April 7, 2021, the AER released a revised edition of Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which is intended to ensure the proper management of liabilities by licensees. The amendments include an annual financial reporting obligation, the expansion of factors the AER may consider in assessing whether an applicant, licensee, or approval holder poses an unreasonable risk, and an obligation for the licensee to notify the AER in the case of default on a debt or a significant change to their working interest participant arrangements. These amendments are intended to approach the risks posed by applicants or licensees proactively and allow the AER to participate in the resolution of issues concerning licensees facing financial difficulties. No timeline has been committed to for the implementation of the AB LMF, however, implementation will likely continue throughout 2022.

On December 1, 2021, the Government of Alberta announced amendments to Directive 006: *Licensee Liability Rating (LLR) Program* and a new Directive 088: *Licensee Life-Cycle Management*, introducing a more comprehensive assessment of corporate health that considers a wider variety of factors than those considered under the Alberta LLR program and establishing clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects.

British Columbia

The BCOGC implements the Liability Management Rating (LMR) Program. Like Alberta's LLR program, the LMR program manages public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations. Under the LMR Program, the BCOGC determines the required security deposits for permit holders under section 30 of the OGAA. Permit holders whose deemed liabilities exceed their deemed assets are considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the legislation, which may result in enforcement action by the BCOGC.

The Government of British Columbia announced amendments to its LMR programs following the Redwater proceedings. In the spring of 2018, the Government of British Columbia passed certain amendments to the OGAA (the "**OGAA Amendments**") which as of April 1, 2019, replace the orphan site reclamation fund tax currently paid by permit holders with a levy paid to the Orphan Site Reclamation Fund ("**OSRF**"). The OGAA Amendments require permit holders to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the OSRF. The levy was phased in, and by 2021/2022 will provide 100% of the annual levy required to fund restoration treatment of orphan sites. The OGAA Amendments permit the B.C. Commission to impose more than one levy in a given calendar year, and until the levy is fully phased in, a production levy will also support the OSRF. In May of 2019, the BCOGC introduced the *Dormancy and Shutdown Regulation*, introducing mandatory timelines for oil and gas site remediation. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the British Columbia Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, the Federal Government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally-provided funds through the Site Rehabilitation Program. In addition to the funds administered by the respective provincial governments, the Federal Government announced a $200 million repayable loan to Alberta's Orphan Well Fund. The Government of British Columbia is disbursing its $120 million share of the federally-provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program and the Legacy Sites Reclamation Program. In Saskatchewan, $400 million in federal funding will be allocated through the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP will make $100 million available to eligible service companies to conduct abandonment and reclamation work. Further tranches of the ASCP, up to $300 million, will be made available in the future.

Indigenous Peoples

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals.

On December 3, 2020, the Federal Government introduced Bill C-15, *An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples* which requires the Federal Government to ensure all Canadian laws are consistent with UNDRIP, implement an action plan to achieve UNDRIP's objectives and table a report on the process of aligning the laws of Canada and on the action plan. On June 21, 2021 Bill C-15 received Royal Assent and came immediately into force. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. Other Canadian jurisdictions have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future.

Recently in British Columbia, an Indigenous group was able to establish that cumulative effects within its traditional territory had reached a "tipping point" resulting in infringement of their treaty rights (see *Yahey v British Columbia*, 2021 BCSC 1287). The Court determined that British Columbia could not authorize new activities within this First Nation's traditional territory, pending consultation and negotiation with the First Nation. Negotiations are ongoing between the Government of British Columbia and the First Nation respecting future authorizations (an interim agreement allowing emergency authorizations has been reached), and, the decision was not appealed by the Government of British Columbia. While this decision is only binding in British Columbia, the long term impacts of this decision on Aboriginal law in Canada overall and in each province are not yet fully understood.

Climate Change Regulation

Federal (Canada) - International Initiatives

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**"). All states that are parties to the UNFCCC are represented at the annual Conference of Parties, the objective of which is to adopt and review legal instruments and strategies to implement goals to stabilize GHG concentrations in the atmosphere to prevent dangerous anthropogenic interference with the climate system.

In December 2015, UNFCCC members agreed to a new climate agreement (the "**Paris Agreement**"), which came into force on November 4, 2016. Canada ratified the Paris Agreement in October 2016. As of March 2022, 193 of the 197 parties to the convention have ratified the Paris Agreement. The Paris Agreement's primary objective is to limit "the increase in the global average temperature to below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C." Individual country targets designed to meet these levels are not legally binding. The Government of Canada has pledged to cut its emissions by 40-45% from 2005 levels by 2030.

Canada also agreed to reduce hydrofluorocarbons ("**HFCs**") through the Kigali Amendment to the Montreal Protocol. The amendment came into force on January 1, 2019 following ratification by 65 countries. Under this agreement, developed countries will incrementally reduce HFC consumption beginning with a 10% reduction in 2019, and reaching an 85% reduction by 2036. Most developing countries will freeze consumption in 2024, with a small number of developing countries with unique circumstances freezing consumption in 2028. The plan also provides financing to certain countries, to help them transition to climate-friendly alternatives. Unlike the Paris Agreement, this agreement is legally binding.

Canada is part of a global initiative called the *Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollutants* (the "**Coalition**"), which has over 100 members, including 73 countries and 78 inter-governmental and non-governmental organizations. The mandate is to address short-lived climate pollutants (e.g., black carbon, methane, tropospheric ozone and HFCs) in order to protect human health and the environment and to slow the rate of climate change. The initiative is to take place in two phases, with the first phase being 98% complete and the second phase taking place between 2022 and 2030.

Federal (Canada) - Domestic Initiatives

Environment and Climate Change Canada coordinates federal initiatives which aim to reduce GHG emissions through a sector-by-sector regulatory approach in order to protect the environment and support economic prosperity. To date, Canada has implemented GHG emission reducing regulations for methane, upstream oil and gas, renewable fuels, transportation, short-lived climate pollutants and coal- and natural gas-fired electricity.

On December 29, 2016, the *Ozone-depleting Substances and Halocarbon Alternatives Regulations* came into force, replacing the *Ozone-depleting Substances Regulations, 1998.* These regulations aim to control the level of production and consumption of certain ozone-depleting substances through a permitting and reporting system for HFCs, as well as a system for phasing out the importation and manufacturing of HFCs in Canada. Amendments to the regulations made in April 2018 added limitations on the importation of products containing HFCs and the destruction of HFCs, created consumption allowances for HFCs and elaborated on the restrictions regarding manufacturing HFCs.

In December 2016, the Government of Canada signed the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). A central feature of the Framework was the creation of a national carbon-pricing program. Accordingly, the Federal Government introduced draft carbon pricing legislation on January 15, 2018, which required all Canadian jurisdictions to implement a carbon-pricing scheme. Provinces and territories are free to implement either a carbon tax or a cap-and-trade system, provided that they meet the federal benchmark carbon price.

On June 21, 2018, the Federal Government enacted the Greenhouse Gas Pollution Pricing Act (the "GGPPA"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20 per tonne of carbon dioxide equivalent ("CO2e"). This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. This ensures that there is a uniform price on emissions across the country. This price escalates by $10 per year until it reaches a price of $50 per tonne of CO2e in 2022. On December 11, 2020, however, the Federal Government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170 per tonne of CO2e in 2030.

Alberta, Saskatchewan, and Ontario referred the constitutionality of the GGPPA to their respective Courts of Appeal. The Alberta Court of Appeal found the federal system to be unconstitutional. Appeals of the Alberta Court of Appeal decision, along with appellate court decisions in both Ontario and Saskatchewan, which found the federal system to be constitutional, were heard by the SCC in September 2020. On March 25, 2021, the SCC ruled that the GGPPA is constitutional. As of November 4, 2021, the federal backstop applies in full in the Yukon, Nunavut, Manitoba, and Ontario, while partially applying in Alberta, Saskatchewan, and Prince Edward Island. Provincial systems in these latter three provinces meet the federal backstop requirements for the emission sources covered, but the GGPPA applies to certain sources not covered by the provincial systems.

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. The regulatory requirements for fugitive equipment leaks and venting from well completion and compressors came into force on January 1, 2020. The regulatory requirements for facility production venting restrictions and venting limits for pneumatic equipment come into force on January 1, 2023. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, while ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit the amount of methane that 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 approximately 20 megatonnes by 2030.

Each of Alberta, British Columbia and Saskatchewan have entered into an equivalency agreement with the Government of Canada, meaning that the federal methane regulations do not apply in those provinces. British Columbia reached such agreement in February 2020, while Alberta and Saskatchewan finalized their agreements in November 2020.

As part of its efforts to provide relief to Canada's crude oil and natural gas industry in light of the COVID-19 pandemic, the Federal Government announced a $750 million Emissions Reduction Fund intended to support pollution reduction initiatives, including methane. Funds disbursed through this program will primarily take the form of repayable contributions to onshore and offshore crude oil and natural gas firms.

Draft Clean Fuel Standard regulations were released in December 2020. Unlike the earlier proposed regulatory framework, the draft regulations apply to liquid fuels only. The Federal Government has indicated that Spring 2022 is being targeted for publication of the final Clean Fuel Standard Regulations. The regulations will require producers or importers of gasoline, diesel, kerosene and light and heavy fuels oils to reduce the carbon intensity of the fuels it produces or imports. The carbon intensity requirements for these regulations will become more stringent over time.

On November 19, 2020, the Federal Government introduced the Canadian Net-Zero Emissions Accountability Act. The bill received Royal Assent as of June 29, 2021. This Act binds the Government of Canada to a process intended to help Canada achieve net zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require the Federal Government to publish annual reports that describe how departments and Crown corporations are considering the financial risks and opportunities of climate change in their decision-making. The Minister of Environment and Climate Change will establish Canada's 2030 Emissions Reduction Plan by the end of March 2022.

Alberta

The *Technology Innovation and Emissions Reduction Regulation* ("**TIER**") replaced the *Carbon Competitiveness Incentive Regulation*, effective January 1, 2020. The TIER system was released pursuant to the *Emissions Management and Climate Resilience Act*. The TIER system improves the management of emissions from large industries such as the oil and gas industry, and encourages industrial facilities to find innovative ways to reduce emissions and invest in clean technology to stay competitive. The TIER system is considered equivalent to the federal carbon-pricing system for 2020, but in the absence of a provincial carbon tax, the federal fuel charge will apply to Alberta-based facilities outside the TIER system. The TIER system will automatically apply to industrial sources that emit greater than 100,000 tonnes of GHG emissions per year. Facilities that do not meet the emissions threshold of 100,000 tonnes of GHG emissions per year can opt-into the TIER system, thereby avoiding the federal fuel charge, if they compete against a facility regulated under the TIER system, or emit over 10,000 tonnes of GHG emissions and belong to a sector with high emissions intensity and trade exposure. Companies in the conventional oil and gas sector will be regulated under the TIER system. On November 3, 2020, the Alberta government increased the rate of its TIER levy from $30/tonne of CO2e in 2020 to $40 in 2021 and will continue to increase it by Ministerial order in subsequent years to stay within the federal requirements.

Facilities subject to TIER have to reduce emissions by 10% in 2020. This reduction requirement "tightens" by an additional 1% annually, beginning in 2021. Facilities regulated under the TIER system have a number of compliance options including payment into a TIER compliance fund at $40 a tonne of carbon dioxide equivalent, use of emission performance credits, use of emission offsets, or a combination of the foregoing.

Currently, the federal backstop applies to all provinces who do not meet the federal threshold. The *Carbon Tax Repeal Act (*Alberta), which came into force on June 4, 2019, eliminated Alberta's provincial carbon tax that was imposed on all carbon-based fuels. As such, Alberta is included as a "listed province" under the federal GGPPA, and the federal backstop standard took effect in Alberta starting January 1, 2020.

In December 2017, Alberta pledged to create a $1.4 billion fund to help industry reduce GHG emissions. The fund will be divided into five categories, including $440 million earmarked for oil sands projects, $225 million available across sectors for projects that support climate change technology and $400 million in loan guarantees to support efficiency and renewable energy measures.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025 as compared to 2014. The Government of Alberta enacted the Methane Emission Reduction Regulation (the "Alberta Methane Regulations") on January 1, 2020, and the AER simultaneously released an updated edition of Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting ("Directive 060"). The release of the updated Directive 060 complements a previously released update to Directive 017: Measurement Requirements for Oil and Gas Operations that took effect in December 2018. Together, these Directives will support Alberta in achieving its 2025 goal. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions, such that the Federal Methane Regulations will not apply in Alberta.

CAPITAL STRUCTURE AND OUTSTANDING SECURITIES

Share Capital

The authorized share capital of Prairie Provident consists of an unlimited number of Common Shares, of which 128,881,511 Common Shares are outstanding as of the date of this AIF (128,724,515 as of December 31, 2021) as fully paid and non-assessable shares.

Holders of Common Shares are entitled to receive notice of and to vote (on the basis of one vote for every share held) at meetings of Prairie Provident shareholders, and subject any priorities attaching to any future class of shares, the right to receive any dividend declared by Prairie Provident and to share rateably in any distribution of its remaining property on dissolution.

The Common Shares are the only voting securities of Prairie Provident.

Dividends

Prairie Provident has not paid any dividends on the Common Shares. Future dividends, if any, will be at the discretion of the Board of Directors, and any decision in respect thereof will be made based on the Company's operating results, cash flow, financial condition and funding requirements for ongoing operations and capital expenditures, and such other business factors and considerations as the Board of Directors considers relevant.

Prairie Provident does not anticipate paying dividends in the near term as cash flow will be reinvested in the Company's assets and operations.

The Company's credit arrangements include negative covenants that restrict Prairie Provident from paying dividends on its Common Shares.

Convertible Securities

As of the date of this AIF, the only outstanding securities of Prairie Provident that are exercisable for or convertible into Common Shares are (i) incentive awards held by directors, officers and employees and outstanding under the Company's security based compensation arrangements; and (ii) the Lender Warrants described above under "*Company Overview and Background – General Development of our Business*".

Outstanding incentive awards at the date of this AIF are comprised of: (i) 2,410,166 incentive stock options held by officers, employees and directors, each exercisable for one Common Share at an exercise price of $0.09 (as to 400,000 options), $0.07 (as to 600,000 options), $0.05 (as to 763,125 options), and $0.21 (as to 647,041 options) per share, subject to vesting in accordance with their terms; (ii) 1,880,268 deferred share units (DSUs) held by non-executive directors, each entitling the holder to receive, on settlement following cessation of service, one Common Share or the cash equivalent thereof; and (iii) 1,352,377 restricted share units (RSUs) held by officers and employees, each entitling the holder to receive, subject to vesting in accordance with their terms, on settlement thereafter, one Common Share or the cash equivalent thereof.

The 34,292,360 Lender Warrants issued in December 2020 (representing 19.9% of the total number of Common Shares then outstanding) are each exercisable for one Common Share at an exercise price of $0.0192 per share (subject to adjustment in certain circumstances) until December 21, 2028; provided that the holder cannot exercise any Lender Warrants that would result in the holder, together with its affiliates and any person with whom the holder acts jointly or in concert, having legal and/or beneficial ownership of, or exercising control or direction over, more than 19.9% of the number of Common Shares (calculated on a non-diluted basis) outstanding at the time. The Lender Warrants can also be exercised on a cashless basis, without payment of the exercise price, for such lesser number of Common Shares as are equal in value to the in-the-money value of the Lender Warrants being exercised (based on the difference between the five-day volume weighted average trading price of the Common Shares and the exercise price).

Debt Securities

Outstanding debt securities are comprised of notes issued to Prudential, as follows: (i) senior secured revolving notes under the Revolving Facility due December 31, 2023; (ii) US$28.5 million original principal amount of Original Notes due June 30, 2024 (plus deferred interest amounts thereon paid in kind); and (iii) US$11.4 million original principal amount of Additional Notes due December 21, 2026 (plus deferred interest amounts thereon paid in kind). See "*Company Overview and Background – General Development of our Business*".

Senior Secured Notes (Revolving Facility)

The Revolving Facility is a borrowing base facility that, as amended on December 29, 2021, currently provides for total revolving commitments equal to the lesser of USD $53.8 million and the then-applicable borrowing base determined by the secured noteholders in accordance with their customary procedures and standards having regard to, among other things, the Company's proved reserves. The borrowing base is subject to reduction to US$50.0 million on December 31, 2022 and to scheduled semi-annual redeterminations thereafter, but without limiting the lenders' right to require a redetermination at any time. Scheduled semi-annual redeterminations follow delivery of year-end and mid-year reserves reports on or before March 31 and September 30. The next scheduled borrowing base redetermination is in Spring 2023 based on a year-end 2022 reserves evaluation.

Under the Revolving Facility, PPR Canada can make further draws under the Revolving Facility on or before the maturity date, subject at all times to the then-applicable commitment amount. Borrowings under the Revolving Facility are repayable at the Company's election at par plus accrued interest and any applicable breakage costs. Repayments generally will not affect the aggregate commitment or borrowing base under the Revolving Facility, except in certain extraordinary circumstances where a repayment will reduce the borrowing base.

The Revolving Facility is ultimately denominated in United States dollars but accommodates Canadian dollar denominated advances up to the lesser of $54 million and the Canadian dollar equivalent of US$30 million. Of the secured notes outstanding under the Revolving Facility at December 31, 2021, $40.5 million are denominated in Canadian dollars (US$30.0 million equivalent using the exchange rate at the time of borrowing).

Amounts borrowed under the Revolving Facility can be drawn in the form of USD or CAD prime advances bearing interest based on reference bank USD and CAD prime lending rates announced from time to time, or LIBOR advances (in the case of USD amounts) or CDOR advances (in the case of CAD amounts) bearing interest based on LIBOR and CDOR rates in effect from time to time, plus an applicable margin. The margin on amounts borrowed under the Revolving Facility is 650 bps per annum above benchmark rates until December 31, 2022, and then 950 bps per annum above benchmark rates thereafter.

The note purchase agreement for the Revolving Facility and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries. Included among the covenants are commitments by PPR Canada to meet certain financial tests, calculated in accordance with the note purchase agreement, with respect to:

- senior leverage ratio, pursuant to which the ratio of senior adjusted indebtedness to EBITDAX for the four quarters most recently ended cannot exceed specified thresholds applicable to each fiscal quarter;

- asset coverage ratio, pursuant to which the ratio of adjusted net present value of estimated future net revenue from proved reserves (discounted at 10% per annum) to adjusted indebtedness as of the date of any reserves report cannot be less than specified thresholds applicable to the reserves report date; and

- current ratio, pursuant to which the ratio of consolidated current assets, plus any undrawn capacity under the Revolving Facility, to consolidated current liabilities at the end of any fiscal quarter cannot be less than specified thresholds applicable to each fiscal quarter.

For purposes of the Revolving Facility, EBITDAX is measured as net earnings before financing charges, foreign exchange gain (loss), E&E expense, income taxes, depreciation, depletion, amortization, other non-cash items of expense and non-recurring items, adjusted for major acquisitions and material dispositions assuming that such transactions had occurred on the first day of the applicable calculation period – all in accordance with the terms of the note purchase agreement and based on financial information from the most recent four consecutive fiscal quarters.

In addition, capital expenditures and acquisitions will generally be limited to consistency with Prairie Provident's annual capital development plan, as created and updated by the Company from time to time and approved by the lenders.

Subordinated Notes

The Subordinated Notes, comprised of US$28.5 million original principal amount of Original Notes due June 30, 2024 (plus deferred interest amounts thereon paid in kind) and US$11.4 million original principal amount of Additional Notes due December 21, 2026 (plus deferred interest amounts thereon paid in kind), are senior unsecured debt obligations of PPR Canada, ranking subordinate to amounts owed under the Revolving Facility.

<u>Maturity</u>
After giving effect to amendments made effective on December 29, 2021, the maturity date of the Original Notes (including with respect to deferred interest amounts thereon paid in kind) is June 30, 2024.
The maturity date of the Additional Notes (including with respect to deferred interest amounts thereon paid in kind) is December 21, 2026.

<u>Interest</u>
The annual interest rate on the Original Notes, originally 15% at the time of first issue, was amended in December 2020 to be nil until June 30, 2021, and to thereafter rise to 4% at the earlier of 15 months after closing (March 2022) and the last day of the fiscal quarter for which the Company's trailing 12-month senior leverage ratio is 2.5 or less, and to 8% at the earlier of 20 months after closing (August 2022) and the last day of the fiscal quarter for which the Company's trailing 12-month senior leverage ratio is 2.0 or less. In accordance with this formula, no interest was in fact payable on the Original Notes during 2021.

The annual interest rate on the Additional Notes is 12%.

Interest on Subordinated Notes is payable quarterly.

<u>Payment-In-Kind</u>
The note purchase agreements (as amended) governing the Revolving Facility and Subordinated Notes require that the Company pay in kind all interest due on the Subordinated Notes for so long as any indebtedness remains outstanding under the Revolving Facility. Prairie Provident will thereafter be permitted to elect to pay in kind up to 4.00% per annum of interest on the Subordinated Notes.

As at December 31, 2021, total deferred interest amounts paid in kind on the Original Notes and outstanding was US$7.0 million, and total deferred interest amounts paid in kind on the Additional Notes and outstanding was US$1.5 million.

<u>Covenants</u>
The note purchase agreements (as amended) for the Subordinated Notes and related parent and subsidiary guarantees contain various covenants on the part of the Company and its subsidiaries, including commitments by PPR Canada to meet the similar financial tests described above with respect to the Revolving Facility but with more relaxed thresholds relative to the ratios applicable under the Revolving Facility. As with the Revolving Facility, capital expenditures and acquisitions will generally be limited to consistency with the Company's annual development plan, as created and updated by the Company from time to time and approved by the lenders.

Escrow

To the knowledge of the directors and executive officers of the Company, other than restrictions applicable to the transfer of incentive awards, there are no securities of Prairie Provident held in escrow or subject to a contractual restriction on transfer.

Market for Securities

The Common Shares commenced trading on the TSX on September 16, 2016 under the symbol "PPR".

Price Range and Trading Volume

The following table sets out the reported high and low trading prices (which are not necessarily the closing prices) and aggregate trading volumes for the Common Shares on the Toronto Stock Exchange, as reported by TMX Datalinx, for the periods indicated.

	Price Range ($)		
	High	Low	Trading Volume
January 2021	0.030	0.015	12,264,018
February 2021	0.065	0.020	17,892,831
March 2021	0.100	0.035	14,100,095
April 2021	0.060	0.035	7,678,740
May 2021	0.070	0.045	8,431,517
June 2021	0.075	0.050	5,321,920
July 2021	0.115	0.070	5,780,745
August 2021	0.090	0.065	2,198,529
September 2021	0.105	0.070	6,181,597
October 2021	0.185	0.095	8,559,990
November 2021	0.180	0.095	4,179,012
December 2021	0.125	0.085	2,841,003
January 2022	0.195	0.125	7,076,505
February 2022	0.190	0.155	5,398,271
March 1-28, 2022	0.310	0.175	9,940,776

Prior Sales

During 2021, Prairie Provident: (i) granted 550,000 DSUs to directors; (ii) granted 1,266,000 RSUs effective May 25, 2021, 400,000 RSUs and 600,000 stock options effective June 28, 2021 and 150,000 RSUs and 400,000 stock options effective September 13, 2021 to officers and employees pursuant to long-term incentive awards; and (iii) issued 401,992 Common Shares on February 5, 2021 and 157,393 Common Shares on December 15, 2021 in partial settlement of vested RSUs previously granted. The closing price on the TSX of the Common Shares on February 5, 2021 and December 15, 2021 were $0.03 and $0.095, respectively.

The DSUs vest immediately upon grant, with each DSU entitling the holder to receive, on settlement following cessation of service, one Common Share or cash equivalent thereof, provided that DSUs granted between July 1, 2019 and December 31, 2021 must be acquired in the secondary market and cannot be new Common Shares issued from treasury. The granted RSUs vest in one-third increments on each of the first and second anniversaries of their grant dates and on December 15 of the third year, with each vested RSU entitling the holder to receive one Common Share or the cash equivalent thereof. The granted stock options vest in one-third increments on each of the first, second and third anniversaries of their grant date, with each vested option entitling the holder to purchase one Common Share at an exercise price of $0.07 per share (with respect to those granted June 28, 2021) and $0.09 per share (with respect to those granted September 13, 2021) for a five-year term expiring June 28, 2026 and September 13, 2026, respectively.

DIRECTORS AND OFFICERS

The following table sets out the names of our directors and executive officers, their jurisdictions of residence, their positions or offices with Prairie Provident and the period during which they have served in such capacities, and their principal occupations during the last five years.

Name, Jurisdiction of Residence and Position with Prairie Provident	Principal Occupations for Past Five Years	Director and/or executive officer since
Patrick McDonald Colorado, USA *Chairman of the Board*	Chief Executive Officer of Carbon Energy Corporation (oil and gas exploration and production) since 2011 and of its predecessor, Nytis Exploration, since 2004	March 2011
Remi Anthony Berthelet Alberta, Canada *President, Chief Executive Officer and a Director*	President and Chief Executive Officer of the Company since June 2021; prior thereto, Chief Operating Officer at Grand Tierra Energy Inc. (oil and gas exploration and production) from October 2019 to January 2021; prior thereto, President and Chief Executive Officer at Strategic Oil & Gas Ltd. (oil and gas exploration and production) from May 2018 until October 2019; prior thereto, Vice President, Development and Operations of Obsidian Energy Ltd. (oil and gas exploration and production) from December 2014 until May 2018	June 2021
Mimi Lai Alberta, Canada *Executive Vice President, Finance and Chief Financial Officer and a Director*	Executive Vice President, Finance and Chief Financial Officer of the Company since July 2021; prior thereto, Vice President, Finance and Chief Financial Officer of the Company since September 2016; prior thereto, Vice President, Finance of the Company since January 1, 2015	January 2015
Derek Petrie Alberta, Canada *Director*	Director of Finance, MILS Group since July 2018; prior thereto, President of R2 Design & Manufacturing (oilfield services and equipment) since February 2016; prior thereto, retired businessman from April 2014 to February 2016	September 2016
Bettina Pierre-Gilles Alberta, Canada *Director*	Founder, President and Chief Executive Officer of Luxeum Renewables Group Inc. (solar power production) since February 2016; prior thereto Owner and Chief Executive Officer of Phansis Consulting since 2003	March 2022
Ajay Sabherwal Washington, DC, USA *Director*	Chief Financial Officer of FTI Consulting, Inc. (business advisory services) since August 2016; prior thereto, Executive Vice President and Chief Financial Officer of FairPoint Communications, Inc. (telecommunications) from July 2010 to August 2016	January 2014
Rob Wonnacott Alberta, Canada *Director*	Principal of NVB Financial Corp. (financial advisory) since 2015; Chief Executive Officer of Pendo Petroleum Inc. (oil and gas exploration and production) from June 2012 to July 2013	September 2011
Ryan Rawlyk Alberta, Canada *Vice President, Production and Operations*	Vice President, Production and Operations of the Company since September 2021; prior thereto, Senior Operations Engineer at InPlay Oil Corp. (oil and gas exploration and production) from March 2020 to July 2021; prior thereto, Vice President Engineering and Corporate Development from September 2019 to February 2020; prior thereto, General Manager Engineering, Operations and Corporate Development at Insignia Energy Ltd. (oil and gas exploration and production) from November 2018 to August 2019; prior thereto, Engineering Manager at Obsidian Energy Ltd. (oil and gas exploration and production) from January 2015 to June 2018	September 2021
Allison Massey Alberta, Canada *Vice President, Land and Commercial*	Vice President, Land and Commercial of the Company since September 2021; prior thereto, Manager, Land Negotiations of Velvet Energy Ltd. (oil and gas exploration and production) since December 2016	September 2021

The following table sets out the membership of the committees of the Board of Directors as of the date of this AIF.

Name of Director	**Audit**	**Compensation**	**Environmental, Social and Governance**	**Executive**	**Nominating and Corporate Governance**	**Reserves and HSE**
Patrick McDonald				Chair	Chair	
Derek Petrie	√	√	√		√	Chair
Bettina Pierre-Gilles	√		Chair			
Ajay Sabherwal	Chair	√	√		√	√
Rob Wonnacott	√	Chair	√			√
Remi Berthelet			√	√		

The term of office of all current directors expires at the close of the next annual meeting of Prairie Provident's shareholders. Ms. Lai will be retiring from Prairie Provident, including as a director, effective March 31, 2022.

As of the date hereof, the directors and executive officers of the Company, as a group, beneficially own or control or direct, directly or indirectly, an aggregate of 2,044,037 Common Shares, representing approximately 1.6% of the outstanding Common Shares (calculated on an undiluted basis).

Messrs. McDonald and Wonnacott were directors of one or more of LPRI, LPR Canada and their affiliates at the time such parties commenced restructuring proceedings under the Companies' Creditors Arrangement Act (Canada) ("**CCAA**") and Chapter 15 of the United States Bankruptcy Code in September 2013, and continued in such capacities through successful implementation of a comprehensive capital reorganization and financial restructuring on January 31, 2014. Mr. McDonald was President and Chief Executive Officer of Forest Oil Corporation at the time of its business combination with Sabine Oil & Gas LLC in December 2014, and continued as a director of that corporation (renamed Sabine Oil & Gas Corporation) until July 2016. In July 2015, Sabine Oil & Gas Corporation and certain of its subsidiaries commenced proceedings under Chapter 11 of the United States Bankruptcy Code.

Mr. Berthelet was President and Chief Executive Officer and a director of Strategic Oil & Gas Ltd. ("SOG"), a public oil and gas company experiencing liquidity constraints in late 2018 and into 2019, at the time of it commencing creditor protection proceedings under the CCAA in April 2019. In the circumstances, SOG did not file its annual financial statements and management's discussion and analysis for the year ended December 31, 2018, which would otherwise have been filed by the prescribed deadline, and became subject to a cease trade order issued in May 2019 as a result (which remains in effect). Mr. Berthelet resigned as a director and officer of SOG in October 2019. In January 2020, the CCAA proceedings of SOG were transitioned to a receivership.

There are potential conflicts of interest to which our directors and officers may become subject in connection with the Company's operations. In particular, certain of our directors have managerial or director positions with other oil and gas companies whose business could compete or interests could conflict with those of the Company, or that may provide financing or services to competitors. Conflicts, if any, will be subject to the procedures and remedies provided under the ABCA. In accordance with the ABCA, any director or officer who is a party to a material contract or material transaction (actual or proposed) with the Company, or is a director or officer of or has a material interest in any person who is a party to a material contract or material transaction (actual or proposed) with the Company, must disclose his or her interest, and is generally prohibited from voting on any resolution to approve the contract or transaction. See also "*Risk Factors – Potential Conflicts of Interest*".

AUDITOR INFORMATION

The auditor of the Company is Ernst & Young LLP, Chartered Professional Accountants, which has served as our auditor since 2011. Ernst & Young LLP is independent with respect to the Company in the context of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

External Auditor Service Fees

Following is a summary of the professional service fees billed to the Company by Ernst & Young LLP for each of the last two financial years.

	Financial year ended December 31,	
(in $000s)	**2020**	**2021**
Audit Fees (1)	191	196
Audit-Related Fees (2)	—	—
Tax Fees (3)	—	—
All Other Fees	1	1
Total Fees	192	197

Notes:

(1) Audit Fees were paid, or were payable for the audit of the Company's annual financial statements and reviews of the quarterly financial statements.

(2) Audit-Related Fees are fees for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements are not reported as "audit fees".

(3) Tax Fees were fees paid or payable for corporate tax return filings, tax advice and tax planning services.

(4) All Other Fees were paid for subscriptions to auditor-provided and supported tools.

RISK FACTORS

The Company is exposed to a number of risks inherent in exploring for, developing and producing crude oil, natural gas and NGLs, some that impact the oil and gas industry as a whole and others that are unique to our operations. This section describes the important risks and other matters that could cause actual results to differ materially from those reflected in forward-looking statements. The impact of any risk or a combination of risks may adversely affect, among other things, our business, reputation, financial condition, results of operations and cash flows. The risks described below may not be the only risks that the Company faces, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. When assessing the materiality of the following risk factors, the Company takes into account a number of qualitative and quantitative factors, including, among others, financial, operational, environmental, regulatory, reputation and safety aspects of the identified risk factor. Events or circumstances described below could materially and adversely affect our business, financial condition, results of operations or cash flows. The risks described below are interconnected, and more than one of these risks could materialized simultaneously or in short sequence if certain events or circumstances described below actually occur. If any of the following risks develop into actual events, our business, financial condition, cash flows or results of operations could be materially and adversely affected. The following risk factors should be read in conjunction with the other information contained herein.

Exploration, Development and Production Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by the Company will result in new discoveries of oil and natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory or development program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the hole and changes in drilling plans and locations as a result of prior wells or additional seismic data and interpretations thereof.

Ability to Find, Develop or Acquire Additional Reserves

Our future oil, natural gas and NGLs reserves and production, and therefore cash flows, are highly dependent upon our success in exploiting our current reserves base and acquiring, discovering or developing additional oil and gas reserves that are economically recoverable. Without additions to reserves through exploration, acquisition or development activities, our production will decline over time as reserves are depleted.

The business of exploring for, developing or acquiring reserves is capital intensive. To the extent our cash flows from operations are insufficient to fund capital expenditures and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil, natural gas and NGL reserves will be impaired. In addition, there can be no certainty that we will be able to find and develop or acquire additional reserves to replace our production at acceptable costs.

Hydrocarbons are a limited resource, and the Company is subject to increasing competition from other companies, including national oil companies. Successful acquisitions require an assessment of a number of factors, many of which are uncertain. These factors include recoverable reserves, development potential, future oil and gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. If a high impact prospect identified by the Company fails to materialize in a given year, our multi-year exploration or development portfolio may be compromised. See "*Risk Factors - Volatility of Crude Oil, Natural Gas and NGL Prices*" in this AIF. A decline in commodity prices may result in promising exploration and development projects being deemed uneconomic. Continued failure to achieve anticipated reserve and resource addition targets may result in our withdrawal from an area, which in turn may result in a write-down of any associated reserves and/or resources for that area.

Exploration and development drilling may not result in commercially productive reserves and, if production begins, reservoir performance may be less than projected. Future oil and gas exploration and development 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. 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, processing or transportation capacity or other geological and mechanical conditions. While diligent 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.

Volatility of Crude Oil, Natural Gas and NGL Prices

Our financial performance and condition are highly sensitive to the prevailing prices of crude oil, natural gas and NGL. Fluctuations in these prices could have a material effect on our operations and financial condition, the value of our oil and natural gas reserves and our level of expenditure for oil and gas exploration and development. Prices for liquids and natural gas fluctuate in response to changes in the supply of and demand for liquids and natural gas, market uncertainty and a variety of additional factors that are largely beyond our control. We currently use derivative instruments to hedge our expected base production so as to manage the impact of fluctuations in crude oil and natural gas prices. See "*Risk Factors - Losses Resulting from Hedging Activities*" in this AIF. Fluctuations in crude oil and gas prices could have a material effect on the volatility of our earnings. Oil prices are largely determined by international supply and demand.

Factors which affect crude oil prices include, among others, actions taken by Saudi Arabia, other members of the Organization of Petroleum Exporting Countries (OPEC) and other major oil producing countries (including Russia), or their state influenced enterprises, to change global crude oil supply or otherwise influence prices, world economic conditions, government regulation, international trade disputes, political stability throughout the world, the foreign supply of crude oil, the price of foreign imports, the ability to secure adequate transportation for products which could be affected by pipeline constraints, the availability of alternative fuel sources, technological advances affecting energy production and consumption, the ongoing impacts of the COVID-19 pandemic, and weather conditions. Any contraction, or deceleration of growth, in the United States, the People's Republic of China and other major oil consuming economies, whatever the cause, will adversely affect oil prices. Historically, NGLs prices have generally been correlated with oil prices, and are determined based on supply and demand in international and domestic NGLs markets. Natural gas prices are impacted by North American inventory levels which have increased year-over-year due to production growth in North America.

The potential causes of conditions that reduce energy demand or increase market uncertainty are innumerable and cannot be predicted with certainty. The COVID-19 pandemic is a current and very significant such cause, with the potential to have materially adverse impacts on public resources, industrial output, employment, consumer spending, international trade, transportation networks, travel, financial markets, investor confidence and governmental priorities, all on a global scale. Its adverse effect on economic, market and business conditions generally, and on oil prices specifically, has been significant, and the duration of its impact remains unknown.

The substantial and extended decline in the prices of crude oil, natural gas and NGLs in recent years has resulted in delay or cancellation of drilling, development or construction programs, and curtailment in production and/or unutilized long-term transportation and drilling commitments, all of which could have a material adverse impact on the Company. Oil and gas producers in Canada currently receive discounted prices for their production relative to certain international prices due to constraints on their ability to transport and sell such production to international markets. A failure to resolve such constraints may result in continued discounted or reduced commodity prices realized by oil and gas producers, including the Company. Poor economics for developing assets have resulted in an industry-wide reduction of drilling activity which may lead to loss of leases and skilled workers. Moreover, changes in commodity prices may result in downward adjustments to our estimated reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require that the Company impair, as a non-cash charge to earnings, the carrying value of our oil and gas properties. The Company is required to perform impairment tests on oil and gas properties whenever events or changes in circumstances indicate that the carrying value of properties may not be recoverable. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and gas properties, the carrying value may not be recoverable and, therefore, an impairment charge will be required to reduce the carrying value of the properties to their estimated fair value. The Company may incur impairment charges in the future, which could materially affect our results of operations, and its balance sheet, in the period incurred.

Any prolonged period of low commodity prices affects our ability to access capital in a number of ways, which include, among others, the following:

- our ability to access new debt or credit markets on acceptable terms may be limited, and this condition may last for an unknown period of time;

- our Revolving Facility limits the amounts the Company can borrow to a borrowing base amount, determined by the secured noteholders in their discretion based on their internal criteria and valuation of our estimated reserves, and that valuation is adversely affected by low commodity prices;

- the note purchase agreements governing our Revolving Facility and the Subordinated Notes require that the Company maintain compliance with the financial ratios described above under "*Capital Structure and Outstanding Securities - Debt Securities*", which include ratios based on an EBITDAX measure that is adversely affected by low commodity prices;

- we may be unable to obtain adequate funding under our Revolving Facility if any secured noteholder is unable or unwilling to meet its commitment; and

- the operating and financial restrictions and covenants under the note purchase agreements governing our Revolving Facility and the Subordinated Notes restrict (and any future debt financing agreements will likely restrict) our ability to finance future operations or capital needs or to engage, expand or pursue our business activities.

Due to these and other factors, the Company cannot be certain that funding will be available, if needed and to the extent required, on acceptable terms, or at all. Specifically, changing investor priorities and trends, including as a result of climate change, ESG initiatives, the adoption of decarbonization policies and the general stigmatization of the oil and gas industry may limit our ability to attract and access capital. If funding is not available when needed, or if funding is available only on unfavorable terms, we may be unable to meet our obligations as they come due or be required to post collateral to support our obligations, or may be unable to meet our drilling commitments, implement our development plans, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues, results of operations or financial condition. Moreover, if we are unable to obtain funding to acquire additional properties containing proved reserves, our total level of estimated oil, natural gas and NGL reserves may decline, and we may be unable to maintain our level of production and cash flow.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by the OPEC and OPEC plus counties, the recent hostilities between the Russian and Ukraine, the COVID-19 pandemic and the ongoing risks facing the North American and global economies.

Uncertainty of Reserve Estimates

The process of estimating oil and gas reserves is complex and involves a significant number of assumptions in evaluating available geological, geophysical, engineering and economic data. In addition, the process requires future projections of reservoir performance and economic conditions; therefore, reserves estimates are inherently uncertain. Since all reserves estimates are, to some degree, uncertain, reserves classification attempts to qualify the degree of uncertainty involved.

Since the evaluation of reserves involves the evaluator's interpretation of available data and projections of price and other economic factors, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on estimated uncertainty, and the estimates of future net revenue or future net cash flows prepared by different evaluators or by the same evaluators at different times may vary substantially. Our actual production, revenues, royalties, taxes, and development and operating expenditures with respect to its reserves will likely vary from such estimates and such variances could be material.

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

Net Present Value of Future Net Revenues

The net present value of future net revenues attributable to our reserves will not necessarily be the same as the current market value of their estimated reserves. Sproule based the estimated discounted future net revenues from proved reserves on certain commodity price assumptions, which assumptions are described in the notes to the reserves tables. Actual future net revenues from our properties will be affected by factors such as:

- actual prices received for oil, natural gas and NGLs;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both production and incurrence of expenses in connection with the development and production of oil, natural gas and NGLs from the properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor used when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with Prairie Provident or the oil and natural gas industry in general. Additionally, such calculation excludes a number of important costs that Prairie Provident will actually incur, such as interest expense, income taxes and general and administrative expenses. Actual future prices and costs may differ materially from those used in the present value estimates included in this AIF.

Operational Risks

Our business is subject to all of the operating risks normally associated with the exploration for, development of and production of natural gas, oil and NGLs. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and liquid spills, acts of vandalism and terrorism, any of which could cause personal injury, result in damage to, or destruction of, natural gas and oil wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations.

In addition, all of our operations will be subject to all of the risks normally incident to the transportation, processing, storing and marketing of natural gas, oil, NGLs and other related products, drilling and completion of natural gas and oil wells, and the operation and development of natural gas and oil properties, including encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of natural gas, oil or well fluids, adverse weather conditions, pollution and other environmental risks.

If any of these industry-operating risks occur, the Company could suffer substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although prior to drilling the Company will obtain insurance in accordance with industry standards to address certain of these 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, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Company's financial position, results of operations or prospects.

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 governmental authorities impose road bans that restrict the movement of drilling and service rigs and other heavy equipment, thereby limiting or temporarily halting drilling and producing activities and other oil and gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also adversely affect our ability to meet drilling objectives and capital commitments, and may increase competition for equipment, supplies and personnel during the winter months, which could lead to shortages and increased costs or delay or temporarily halt operations.

Risks Related to Mergers and Acquisitions

The Company believes that possible future mergers or acquisitions may strengthen our position and create the opportunity to realize certain benefits, including, among other things, operational synergies and potential cost savings. Achieving the benefits of mergers or acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as being able to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations. Mergers and acquisitions could also result in difficulties in being able to hire, train or retain qualified personnel to manage and operate such properties.

Acquiring oil and gas properties requires the Company to assess reservoir and infrastructure characteristics, including estimated recoverable reserves, type curve performance and future production, commodity prices, revenues, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and, as such, the acquired properties may not produce as expected, may not have the anticipated reserves and may be subject to increased costs and liabilities.

Although the acquired properties are reviewed prior to completion of an acquisition, such reviews are not capable of identifying all existing or potentially adverse conditions. This risk may be magnified where the acquired properties are in geographic areas where the Company has not historically operated or in new or emerging formations. New or emerging formations and areas often have limited or no production history and we may be less able to predict future drilling and production results over the life-cycles of the wells in such areas.

Further, the Company may not be able to obtain or realize upon contractual indemnities from the seller for liabilities created prior to an acquisition, and may be required to assume the risk of the physical condition of the properties that may not perform in accordance with expectations.

Capital Allocation and Project Decisions

Our long-term financial performance is sensitive to the capital allocation decisions taken and the underlying performance of the projects undertaken. Capital allocation and project decisions are undertaken after assessing reserve and production projections, capital and operating cost estimates and applicable fiscal regimes that govern the respective government take from any project. All of these factors are evaluated against common commodity pricing assumptions and the relative risks of projects. These factors are used to establish a relative ranking of projects and capital allocation, which is then calibrated to ensure the debt and liquidity of the Company is not compromised. However, material changes to project outcomes and deviation from forecasted assumptions, such as production volumes and rates, realized commodity price, cost or tax and/or royalties, could have a material impact on our cash flow and financial performance as well as assessed impacts of impairments on our assets. Adverse economic and/or fiscal conditions could impact the prioritization of projects and capital allocation to these projects, which in turn could lead to adverse effects such as asset under investment, asset performance impairments or land access expiries.

Project Delivery

Our ability to operate, generate sufficient cash flows, and complete projects depends upon numerous factors beyond our control. In addition to commodity prices and continued market demand for its products, these non-controllable factors include, among others, general business and market conditions, economic recessions and financial market turmoil, the overall state of the capital markets, including investor appetite for investments in the oil and gas industry generally and our securities in particular, the ability to secure and maintain cost effective financing for its commitments, legislative, environmental and regulatory matters, reliance on industry partners and service providers, unexpected cost increases, royalties, taxes, and volatility in oil, natural gas or NGL prices. Global demand for project resources can impact the access to appropriately competent contractors and construction yards as well as to raw products, such as steel. Typical execution risks include, among others, the availability of seismic data, the availability of pipeline and processing capacity, transportation interruptions and constraints, technology failures, accidents, reservoir quality, the availability and proximity of pipeline capacity, the availability of drilling and other equipment, the ability to access water for hydraulic fracturing operations, the ability to access lands, weather, unexpected cost increases, accidents, the availability of skilled labour, including engineering and project planning personnel, the need for government approvals and permits, and regulatory matters. Subsurface challenges can also result in additional risk of cost overruns and scheduling delays if conditions are not typical of historical experiences. The Company utilizes materials and services which are subject to general industry-wide conditions. Cost escalation for materials and services may be unrelated to commodity price changes and may continue to have a significant impact on project planning and economics. In addition, some of these risks may be magnified due to the concentrated nature of funding certain assets within our portfolio of oil and natural gas properties that are operated within limited geographic areas. As a result, a number of our assets could experience any of the same risks and conditions at the same time, resulting in a relatively greater impact on our financial condition and results of operations compared to other companies that may have a more geographically diversified portfolio of properties.

Declines in oil, natural gas or NGLs prices or a continued low price environment for natural gas, oil or NGLs create fiscal challenges for the oil and gas industry. These conditions have impacted companies in the oil and gas industry and our spending and operating plans and may continue to do so in the future. There may be unexpected business impacts from market uncertainty, including volatile changes in currency exchange rates, inflation, interest rates, defaults of suppliers and general levels of investing and consuming activity.

The Company manages a variety of projects, including exploration and development projects. Project delays may impact expected revenues and project cost overruns could make projects uneconomic.

All of our operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact our existing and planned projects.

Egress and Gas and Liquid Buyers

The Company delivers its products through gathering, processing and pipeline systems (some of which we do not own). The amount of oil and natural gas that we can sell is subject to the accessibility, availability, proximity and capacity of these systems. This access to market affects regional price differentials, which could result in the inability to realize the full economic potential of our production. Although transportation systems are expanding, the lack of firm transportation capacity continues to affect the industry and has the potential to limit the ability to produce and to market our production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil. North America has an integrated network of natural gas pipelines; however regional restrictions can arise resulting in curtailments. Any significant change in market factors, infrastructure regulation or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could negatively impact our business and, in turn, its financial condition, results of operations and funds from operations. A portion of our production is processed through third-party owned facilities that we do not control. From time-to-time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could adversely affect our ability to process its production and to deliver the same for sale.

Credit and Liquidity

Market events and conditions, including disruptions in the international credit markets and other financial systems and sovereign debt levels, may cause significant volatility of the credit markets, which may then restrict timely access and limit our ability to secure and maintain cost-effective financing on acceptable terms and conditions. Specifically, changing investor priorities and trends, including as a result of climate change, ESG initiatives, the adoption of decarbonization policies and the general stigmatization of the oil and gas industry may limit our ability to attract and access capital. In addition, if any lender under our Revolving Facility does not fund its commitment, our liquidity may be reduced by an amount up to the aggregate amount of such lender's commitment. See "*Risk Factors - Counterparty Risk*" in this AIF. Further, our ability to access funds under our Revolving Facility is based on a borrowing base, which is subject to periodic redeterminations and will be determined by the secured noteholders in their discretion based on their internal criteria and valuation of our estimated reserves. There can be no assurance that the noteholders will maintain our borrowing base at current levels or at levels that otherwise meet the Company's liquidity and capital resource requirements.

Our ability to access the private and public equity and debt markets and complete future asset monetization transactions is also dependent upon oil, natural gas and NGL prices, in addition to a number of other factors, some of which are outside our control. These factors include, among others:

- the value and performance of our debt and equity securities;
- domestic and global economic conditions; and
- conditions in the domestic and global financial markets.

See also "*Risk Factors - Volatility of Crude Oil, Natural Gas and NGL Prices*" in this AIF.

Recent credit concerns and related turmoil in the energy sector and disruption to the broader economy have adversely impacted our business and access to capital, and we may face additional challenges if these economic and financial market conditions persist or worsen. The materially adverse impacts of the COVID-19 pandemic on public resources, industrial output, employment, consumer spending, international trade, transportation networks, travel, financial markets, investor confidence and governmental priorities are significant. The weakened economic conditions also may adversely affect the collectability of our trade receivables. For example, our accounts receivable are primarily from purchasers of our oil, natural gas and NGL production and other exploration and production companies that own working interests in the properties that we operate. This industry concentration could adversely impact our overall credit risk because our customers and working interest owners may be similarly affected by changes in economic and financial market conditions, commodity prices and other conditions. Further, a credit crisis and turmoil in the financial markets in the future could cause our commodity derivative instruments to be ineffective in the event a counterparty is unable to perform its obligations or seeks bankruptcy protection.

Due to these and other factors, the Company cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms, or at all. If we are unable to access funding when needed on acceptable terms, we may not be able to implement our business plans, meet our capital commitments, take advantage of business opportunities, respond to competitive pressures or refinance our debt obligations as they come due, any of which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Operating Restrictions under our Credit Arrangements

The note purchase agreements governing our Revolving Facility and the Subordinated Notes contain, and future agreements governing replacement or other indebtedness will likely contain, restrictive covenants that impose significant operating and financial restrictions on the Company, including restrictions on our ability to, among other things:

- sell assets, including equity interests in its subsidiaries;
- pay dividends on, redeem or repurchase Prairie Provident shares;
- make investments other than the ownership and related operation of oil and gas properties and assets in Canada;
- incur or guarantee additional indebtedness or issue preferred shares;
- create or incur certain liens;
- make certain acquisitions and investments;

- enter into agreements that restrict distributions or other payments from restricted subsidiaries;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into certain sale and leaseback transactions; and
- engage in certain business activities.

The note purchase agreements governing our Revolving Facility and the Subordinated Notes also require that the Company maintain compliance with the financial ratios described above under "*Capital Structure and Outstanding Securities - Debt Securities*".

As a result of these covenants and restrictions the Company will be limited in the conduct of its business, and may therefore be unable to engage in favorable business activities or finance future operations or capital needs. Our ability to comply with these covenants and restrictions in the future is uncertain and will be affected by prevailing commodity prices and other events and circumstances beyond the Company's control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired.

The note purchase agreement governing our Revolving Facility also limits the amounts the Company can borrow to a borrowing base amount, determined by the secured noteholders in their discretion based on their internal criteria and valuation of our estimated reserves. Outstanding borrowings in excess of the borrowing base must be repaid with interest. If the Company does not have sufficient funds on hand for such repayment, we may be required to seek a waiver or amendment from our lenders, refinance our debt, sell assets or issue equity or more debt. The Company may not be able to obtain such financing or complete such transactions on acceptable terms, or at all. Failure to make any required repayment could result in an event of default under our credit arrangements.

A failure to comply with requirements of the note purchase agreements governing our Revolving Facility and the Subordinated Notes (or of any future debt financing agreements) could result in an event of default under the agreement, which, if not cured or waived, could have a material adverse effect on our business, financial condition, cash flows and results of operations. If an event of default under either note purchase agreement occurs and remains uncured, the lenders thereunder:

- in the case of the Revolving Facility, would not be required to advance any additional amounts thereunder;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest thereon and fees, to be immediately due and payable;
- may require the Company to apply all available cash to repay these borrowings; or
- may prevent the Company from making debt service payments under other agreements.

Our level of indebtedness could affect our operations by:

- requiring the Company to dedicate a portion of cash flows from operations to service indebtedness, thereby reducing the availability of cash flow for other purposes;
- reducing our competitiveness compared to similar companies that have less debt;

- limiting our ability to obtain additional future financing for working capital, capital investments and acquisitions;
- limiting our flexibility in planning for, or reacting to, changes in our business and industry; and
- increasing our vulnerability to general adverse economic and industry conditions.

Our ability to meet and service our debt obligations depends on future performance. General economic conditions, natural gas, oil or NGL prices, and financial, business and other factors affect our operations and future performance. Many of these factors are beyond our control. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance debt or repay debt with proceeds from an offering of securities or sale of assets. No assurance can be given that the Company will be able to generate sufficient cash flow to pay the interest obligations on our debt, or that funds from future borrowings, equity financings or proceeds from the asset sales will be available to pay or refinance our debt, at all or on acceptable terms. Further, future acquisitions may decrease our liquidity by using a significant portion of available cash or borrowing capacity to finance such acquisitions, and such acquisitions could result in a significant increase in our interest expense or financial leverage if the Company incurs additional debt to finance the acquisitions.

Ownership of the Common Shares

The market price of our Common Shares is sensitive to a variety of market based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates and the comparability of the Common Shares to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

There may be future dilution to our shareholders. One of our objectives is to continually add to our reserves through acquisitions and through development. Our success in growth from acquisitions and development may, in part, depend on our ability to raise capital from time to time by selling additional Common Shares. Shareholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common Shares issued to acquire those assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to effect acquisitions.

Sale of Additional Securities

The Company may issue an unlimited number of additional Common shares and other securities in the future to finance its activities without the approval of shareholders. Subject to the policies of the TSX, the Board of Directors has the discretion to set the price and terms of the issuance of any such additional securities, and any issuance of additional securities may have a dilutive effect on the holders of Common Shares.

Major Incident, Major Spill / Loss of Well Control

Oil and gas drilling and producing operations are subject to many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome, including, among others, the risk of fire, explosions, mechanical failure, pipe or well cement failure, well casing collapse, pressure or irregularities in formations, chemical and other spills, unauthorized access to hydrocarbons, illegal tapping of pipelines, accidental flows of oil, natural gas or well fluids, sour gas releases, contamination, vessel collision, structural failure, loss of buoyancy, storms or other adverse weather conditions and other occurrences. If any of these should occur, the Company could incur legal defence costs and remedial costs and could suffer substantial losses due to injury or loss of life, human health risks, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, unplanned production outage, cleanup responsibilities, regulatory investigation and penalties, increased public interest in our operational performance and suspension of operations. Our application of horizontal and multi-stage hydraulic fracture stimulation techniques involve greater risk of mechanical problems than vertical and shallow drilling operations.

Health Hazards and Personal Safety Incidents

The employee and contractor personnel involved in exploration and production activities and operations of the Company are subject to many inherent health and safety risks and hazards, which could result in occupational illness or health issues, personal injury, and loss of life, facility quarantine and/or facility and personnel evacuation.

Regulatory Approvals / Compliance and Changes to Laws and Regulations

Our exploration and production operations are subject to extensive regulation at many levels of government, including municipal, state, provincial and federal governments, and operations are subject to interruption or termination by governmental and regulatory authorities based on environmental or other considerations. Moreover, the Company has incurred and will continue to incur costs in our efforts to comply with the requirements of environmental, safety and other regulations. Further, the regulatory environment in the oil and gas industry could change in ways that we cannot predict and that might substantially increase our costs of compliance and, in turn, materially and adversely affect our business, results of operations and financial condition.

Failure to comply with the applicable laws or regulations may result in significant increases in costs, fines or penalties and even shutdowns or losses of operating licences or criminal sanctions. If regulatory approvals or permits required for operations are delayed or not obtained, the Company could experience delays or abandonment of projects, decreases in production and increases in costs. This could result in our inability to fully execute the Company's strategy and adversely impact our financial condition. See "*Risk Factors - Sociopolitical Risks*" in this AIF.

Changes to existing laws and regulations or new laws could have an adverse effect on our business by increasing costs, impacting development schedules, reducing revenue and cash flow from natural gas and oil sales, reducing liquidity, limiting operations or otherwise altering the way the Company conducts business. There have been various proposals to enact new, or amend existing, laws and regulations relating to GHG emissions, hydraulic fracturing (including associated additives, water use, induced seismicity, and disposal) and shale gas development generally. See "*Risk Factors - Environmental Risks*" in this AIF.

The Company continues to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact on our operations. Governmental actors unilaterally control the timing, scope and effect of any currently proposed or future laws or regulations, and such enactments are subject to a myriad of factors, including political, economic and social pressures. The direct and indirect costs of such laws and regulations (if enacted) could materially and adversely affect our business, results of operations and financial condition.

Fiscal Stability

Governments may amend or create new legislation that could impact our operations and that could result in increased capital, operating and compliance costs. Moreover, our operations are subject to various levels of taxation in the jurisdictions in which the Company operates. Federal, provincial and territorial income tax rates or incentive programs relating to the oil and gas industry in the jurisdictions where we operate may in the future be changed or interpreted in a manner that could materially affect the economic value of the relevant assets. In addition, there can be no assurance that the applicable provincial governments will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's earnings and could make future capital investments, or the Company's operations, less economic. In particular, on January 29, 2016, the Government of Alberta adopted a new royalty regime that took effect on January 1, 2017 to incorporate a single royalty structure for crude oil, liquids and gas.

The Government of Alberta passed the Royalty Guarantee Act on July 18, 2019, ensuring that when a well is drilled, the royalty structure will remain in place for at least ten years, subject to certain listed exceptions. On July 23, 2020, the Red Tape Reduction Implementation Act, received Royal Assent. The Red Tape Reduction Implementation Act amends, among other acts, the Mines and Minerals Act (Alberta), allowing the Alberta Minister of Energy to make changes to royalty rates without Cabinet's approval. There can be no assurances that the Government of Alberta will not amend or repeal these Acts, or that the Government of Canada will not adopt new royalty regimes, which may render the Company's projects uneconomic or otherwise adversely affect its results of operations, financial condition or prospects. See "*Industry Conditions - Royalties*".

Stakeholder Opposition

Our planned activities may be adversely affected if there is strong community opposition to our operations. For example, there is heightened public concern regarding hydraulic fracturing in parts of North America, which could materially affect our shale operations. In some circumstances, this risk of community opposition may be higher in areas where Prairie Provident operates alongside Indigenous communities who may have additional concerns regarding land ownership, usage or claim compensation.

Further, with increasing public focus on climate change and GHG emissions, the reputations of oil and gas companies generally may become increasingly unfavourable. There are added social pressures which demand governments and companies to work to mitigate the risks associated with climate change, decrease GHG emissions and move towards decarbonization. Specifically, there is a reputational risk in connection with the Company's ability to meet increasing climate reporting and emission reduction expectations from key stakeholders. The Company has been actively preparing and adapting to manage and respond to investors' increasing expectations by proactively preparing voluntary reports on ESG initiatives, investing in energy efficiency and emissions reduction projects and integrating ESG across the business.

Non-Operatorship and Partner Relationships

Some of our projects are conducted through, joint ventures, partnerships or other arrangements, where Prairie Provident has a limited ability to influence or control operations (or their associated costs) or future development, safety and environmental standards and amount of capital expenditures. Companies which operate these properties may not necessarily share our health, safety and environmental standards or strategic or operational goals or approach to partner relationships, which may result in accidents, regulatory noncompliance, project delays or unexpected future costs, all of which may affect the viability of these projects and our standing in the external market. Our dependence on the operator and other working interest owners for these properties and assets, and its limited ability to influence operations and associated costs, could materially adversely affect our financial performance. The success and timing of our activities on assets operated by others therefore will depend upon a number of factors that are outside of our control, including timing and amount of capital expenditures, timing and amount of operating and maintenance expenditures, the operator's expertise and financial resources, approval of other participants, selection of technology and risk management practices.

If these co-participants do not approve or are unable to fund their contractual share of certain capital or operating expenditures, suspend or terminate such arrangements or otherwise fulfill their obligations, this may result in project delays or additional future costs to the Company, all of which may affect the viability of such projects.

These co-participants may also have strategic plans, objectives and interests that do not coincide with and may conflict with those of the Company. While certain operational decisions may be made solely at our discretion as operator of certain projects, major capital and strategic decisions affecting such projects may require agreement among the co-participants. While the Company and its co-participants generally seek consensus with respect to major decisions concerning the direction and operation of the project assets, no assurance can be provided that the future demands or expectations of any party, including the Company, relating to such assets will be met satisfactorily or in a timely manner. Failure to satisfactorily meet such demands or expectations may affect our or our co-participants' participation in the operation of such assets or the timing for undertaking various activities, which could negatively affect our operations and financial results. Further, the Company is involved from time to time in disputes with its co-participants and, as such, we may be unable to dispose of assets or interests in certain arrangements if such disputes cannot be resolved in a satisfactory or timely manner.

Losses Resulting from Hedging Activities

The nature of our operations results in exposure to fluctuations in commodity prices. To reduce our exposure to fluctuations in oil, natural gas and NGL prices, the Company enters into derivative instruments (or hedging agreements) for a portion of its oil, natural gas and NGL production. We expect that our commodity hedging agreements will be limited in duration, usually for periods of three years or less; however, in conjunction with acquisitions, we may enter into or acquire hedges for longer periods. The terms of our various hedging agreements may limit the benefit to the Company of commodity price improvements. We may also suffer financial loss if the Company is unable to produce natural gas, oil or NGLs, or if counterparties to our hedging agreements fail to fulfill their obligations under the hedging agreements.

Our hedging transactions will impact our earnings in various ways, known and unknown. Due to the volatility of commodity prices, the Company may be required to recognize mark-to-market gains and losses on derivative instruments, as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period-to-period estimates and will be a function of the actual price of the commodities on the settlement date of the particular derivative instrument. The Company expects that commodity prices will continue to fluctuate in the future, and, as a result, our periodic financial results will be subject to fluctuations related to its derivative instruments.

Attraction, Retention and Development of Personnel

The success of the Company will depend in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on the Company. The Company does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Company are likely to be of central importance. There can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. This includes not only key personnel at a senior level, but also individuals with the professional and technical skill sets critical for our business, particularly geologists, geophysicists, engineers, accountants and other specialists. Any deterioration of our corporate culture could adversely affect our operations and long-term success. Any external circumstance that renders our personnel unable to work, or disrupts their ability to effectively access the workplace resources necessary to discharge their responsibilities for the Company, will also adversely affect our operations. The effect of the COVID-19 pandemic, including any adverse impact on employee health and responsible and proper measures to limit physical proximity among personnel, is such a circumstance.

Information Systems

The Company has become increasingly dependent upon the availability, capacity, reliability and security of our information technology (IT) infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. We depend on various IT systems to estimate reserve quantities, process and record financial and operating data, analyze seismic and drilling information, and communicate with employees and third-party partners. Our IT systems are increasingly integrated in terms of geography, number of systems, and key resources supporting the delivery of IT systems. The performance of our key suppliers is critical to ensure appropriate delivery of key services. Any failure to manage, expand and update our IT infrastructure, any failure in the extension or operation of this infrastructure, or any failure by our key resources or service providers in the performance of their services could materially and adversely harm our business.

The ability of the IT function to support our business in the event of a disaster such as fire, flood or loss/denial of any of our data centres or major office locations and our ability to recover key systems from unexpected interruptions cannot be fully tested. There is a risk that, if such an event actually occurs, the business continuity plan may not be adequate to immediately address all repercussions of the disaster. In the event of a disaster affecting a data centre or key office location, key systems may be unavailable for a number of days, leading to inability to perform some business processes in a timely manner.

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 our business activities or its competitive position. Further, disruption of critical IT services, or breaches of information security, could have a negative effect on our operational performance and earnings, as well as on our reputation.

The Company applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however these controls may not adequately prevent cyber-security breaches. There is no assurance that the Company will not suffer losses associated with cyber-security breaches in the future, and we may be required to expend significant additional resources to investigate, mitigate and remediate any potential vulnerabilities.

Claims, Litigation, Administrative Proceedings and Regulatory Actions

The Company may be subject to claims, litigation, administrative proceedings and regulatory actions. The outcome of these matters may be difficult to assess or quantify, and there cannot be any assurance that such matters will be resolved in our favour. If we are unable to resolve such matters favourably, the Company or its directors, officers or employees may become involved in legal proceedings that could result in an onerous or unfavourable decision, including fines, sanctions, monetary damages or the inability to engage in certain operations or transactions. The defense of such matters may also be costly and time consuming, and could divert the attention of management and key personnel from our operations. The Company may also be subject to adverse publicity associated with such matters, whether or not allegations are valid or we are ultimately found liable. As a result, such matters could have a material adverse effect on our reputation, financial position, results of operations or liquidity.

Securing and Maintaining Title to Properties

Our oil and gas properties are held in the form of licenses and leases and working interests in licenses and leases. If the Company or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse effect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of its properties. Furthermore, there may be legislative changes which affect title to the oil and gas properties we control that, if successful or made into law, could impair our activities on the properties and result in a reduction of the revenue received.

Claims Made by Aboriginal Peoples

Aboriginal peoples have claimed Aboriginal title and rights to portions of Western Canada. We are not aware that any material claims have been made in respect of our properties and assets; however, if a claim arose and was successful this could have an adverse effect on the Company and our operations.

On December 3, 2020, the Federal Government introduced Bill C-15, An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples which requires the Federal Government to ensure all Canadian laws are consistent with UNDRIP, implement an action plan to achieve UNDRIP's objectives and table a report on the process of aligning the laws of Canada and on the action plan. On June 21, 2021 Bill C-15 received Royal Assent and came immediately into force. Additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Recently in British Columbia, an Indigenous group was able to establish that cumulative effects within its traditional territory had reached a "tipping point" resulting in infringement of their treaty rights (see Yahey v British Columbia, 2021 BCSC 1287). The court determined that British Columbia could not authorize new activities within this First Nation's traditional territory, pending consultation and negotiation with the First Nation. Negotiations are ongoing between the Government of British Columbia and the First Nation respecting future authorizations (an interim agreement allowing emergency authorizations has been reached), and, the decision was not appealed by the

Government of British Columbia. While this decision does not create binding precedent in Alberta and the long term impacts of this decision on Aboriginal law in Canada overall and in Alberta are not yet fully understood, a similar claim, if successful, that encompasses the Company's projects could have a significant adverse effect on the Company.

Sociopolitical Risks

Our operations may be adversely affected by political or economic developments or social instability in the jurisdictions in which we operate, which are not within our control, including, among other things, a change in crude oil, natural gas or NGL pricing policy and/or related regulatory delays, the risks of war, terrorism, abduction, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, difficulties in enforcing contractual terms, a change in taxation policies, economic sanctions, the imposition of specific drilling obligations, the imposition of rules relating to development and abandonment of fields, access to or development of infrastructure, jurisdictional boundary disputes, and currency controls.

Additionally, the marketability and price of oil and gas is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, including the recent hostilities between Russia and Ukraine, have a significant impact on the price of oil and gas. Any particular event could result in a material decline in prices and therefore could have a material adverse effect on the Company's results of operations, financial condition and prospects.

Future Changes in Laws

Income tax laws, royalty regimes, environmental laws or other laws and regulations may in the future be changed or interpreted in a manner that adversely affects the Company or our security holders. Changes to existing laws and regulations or the adoption of new laws and regulations could also increase our cost of compliance and adversely affect our business, financial position, cash flows or results of operations.

Exchange Rate Fluctuations

World oil prices are quoted in U.S. dollars. An increase (or decrease) in the exchange rate for the Canadian dollar versus the U.S. dollar would result in the receipt by the Company of fewer (or more) Canadian dollars for its production. Our expenses are primarily denominated in Canadian dollars. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could impact our revenue and expenses and have an adverse effect on our financial performance and condition. The Company monitors and, when appropriate, uses derivative financial instruments to manage its exposure to currency exchange rate risk. Changes in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates may also impact the future value of the Company's reserves as determined by independent evaluators.

Counterparty Risk

The Company is exposed to the risks associated with counterparty performance including credit risk and performance risk. We may experience material financial losses in the event of customer payment default for commodity sales and financial derivative transactions. Our liquidity may also be impacted if any lender under our existing Revolving Facility is unable or unwilling to fund its commitment. Performance risk can impact our operations by the non-delivery of contracted products or services by counterparties, which could impact project timelines or operational efficiency. Fluctuations in prevailing prices of crude oil, natural gas and NGLs could have a material adverse effect on the operations and financial condition of counterparties. The Company also has credit risk arising from cash and cash equivalents held with banks and financial institutions.

Interest Rates

The Company is exposed to interest rate risk principally by virtue of our borrowings. Borrowing at floating rates exposes the Company to movements in interest rates. Borrowing at fixed rates exposes the Company to reset risk associated with debt maturity. Variations in interest rates and schedule principal repayments could result in changes in the amount required to service debt, which may negatively impact our cash flows and financial condition.

Competitive Risk

The global oil and gas industry is highly competitive. The Company faces significant competition and many of our competitors have resources in excess of our available resources. We actively compete for the acquisition and divestment of properties, the exploration for and development of new sources of supply, the contractual services for oil and gas drilling and production equipment and services, the transportation and marketing of current production, and industry personnel, including, but not limited to, geologists, geophysicists, engineers and other specialists that enable the business. Many of our competitors have the ability to pay more for seismic and lease rights in crude oil and natural gas properties and exploratory prospects. They can define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. If we are not successful in the competition for oil and gas reserves or in the marketing of production, our financial condition and results of operations may be adversely affected. Many of our competitors have resources substantially greater than our and, as a consequence, the Company may be at a competitive disadvantage. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. Some of these industries benefit from lighter regulation, lower taxes and subsidies. In addition, certain of these industries are less capital intensive.

Income Taxes

Income tax laws, other laws or government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects the Company and our shareholders. Tax authorities having jurisdiction over the Company or our securityholders may disagree with how the Company calculates our income for tax purposes or tax liabilities or structure our arrangements, or could change their administrative practices, to the detriment of the Company or our securityholders. The Company is also subject to income tax audit and reassessment risks, the outcome of which may result in reduction in our tax pools, loss carry-forwards, or even cash tax liabilities. Reduction in our future income tax deductibility and any cash tax payable will lower our future cash flows and negatively impact its financial condition.

Inflation

The Company does not believe that inflation has had a material effect on our business, financial condition or results of operations to date; however, if the Company's development, operation or labour costs were to become subject to significant inflationary pressures, we may not be able to fully offset such higher costs through corresponding increases in commodity prices. Inability or failure to do so could harm the Company's business, financial condition and results of operations.

Environmental Risks

General

All phases of our oil, natural gas and NGL business are subject to environmental regulation pursuant to a variety of laws and regulations in the jurisdictions in which we do business (collectively, "**environmental regulation**").

Environmental regulation imposes, among other things, restrictions, liabilities and obligations in connection with the use, generation, handling, storage, transportation, treatment and disposal of chemicals, hazardous substances and waste associated with the finding, production, transmission and storage of our products, including the hydraulic fracturing of wells, the decommissioning of facilities and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and natural gas operations.

Environmental regulation also requires that wells, facility sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations including exploration and development projects and changes to certain existing projects may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties.

Although the Company currently believes that the costs of complying with environmental legislation and dealing with environmental civil liabilities will not have a material adverse effect on our financial condition or results of operations, there can be no assurance that such costs will not have such an effect in the future.

Our business is subject to the trend toward increased rigour in regulatory compliance and civil or criminal liability for environmental matters in Canada. Compliance with environmental legislation can require significant expenditures, and failure to comply with environmental legislation may result in the assessment of administrative, civil and criminal penalties, the cancellation or suspension of regulatory permits, the imposition of investigatory or remedial obligations or the issuance of injunctions restricting or prohibiting certain activities. Under existing environmental laws and regulations, the Company could be held strictly liable for the remediation of previously released materials or property contamination resulting from our operations, regardless of whether those operations were in compliance with all applicable laws at the time they were performed. Regulatory delays, legal proceedings and reputational impacts from an environmental incident could result in a material adverse effect on our business. Increased stakeholder concerns and regulatory actions regarding shale gas development could lead to third party or governmental claims, and could adversely affect our business and financial condition.

British Columbia, Quebec, New Brunswick, Nova Scotia, Newfoundland and Labrador and the Northwest Territories have all implemented carbon pricing mechanisms which meet or exceed the current federal benchmark carbon price of $30 per tonne. The federal backstop standard went into effect on April 1, 2019 and affects provinces and territories which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing. As of November 4, 2021, the federal backstop applies in full in the Yukon, Nunavut, Manitoba and Ontario, while partially applying in Alberta, Saskatchewan and Prince Edward Island. Alberta was included on this list, despite its introduction of the TIER system, due to the provincial government's elimination of the Climate Leadership Regulation. As the TIER system only applies to certain classes of large industrial emitters and does not include an economy-wide price on carbon, the federal backstop will apply to sources in Alberta not governed by the TIER, including smaller industrial emitters and households. The federal benchmark carbon levy had an initial rate of $20 per tonne, increasing by $10 per tonne annually until it reaches $50 per tonne in 2022. In December 2020, the Federal Government proposed increasing the price on carbon to $170 per tonne by 2030. To reach that level, the price imposed on carbon will rise from the 2022 rate of $50 per tonne by $15 per tonne each year. The direct or indirect costs of compliance with these regulations, as well as other regulations relating to the pricing and reduction of GHG emissions, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Hydraulic Fracturing

The Company utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated drilling fluids and other technologies in its drilling and completion activities. Hydraulic fracturing is a method of increasing well production by injecting fluid under high pressure down a well, which causes the surrounding rock to crack or fracture. The fluid typically consists of water, sand, chemicals and other additives and flows into the cracks where the sand remains to keep the cracks open and enable natural gas or liquids to be recovered. Fracturing fluids flow back to the surface through the wellbore and are stored for reuse or future disposal in accordance with regional regulations, which may include injection into underground wells. The design of the well bores protects groundwater aquifers from the fracturing process.

Hydraulic fracturing has been in use for some time in the oil and gas industry; however, the proliferation of fracturing in recent years to access hydrocarbons in unconventional reservoirs, such as shale formations, has given rise to public concerns about the environmental impacts of this technology. Public concern over the environmental impacts of the hydraulic fracturing process has focused on a number of issues, including water aquifer contamination; other qualitative and quantitative effects on water resources as large quantities of water are used and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed; and the potential for fracturing activities to induce seismic events. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial, territorial and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements, or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs and third party or governmental claims. They could also increase our costs of compliance and doing business as well as delay the development of hydrocarbon (natural gas and oil) resources from shale formations, which may not be commercial without the use of hydraulic fracturing.

If legal restrictions are adopted in jurisdictions in which the Company is currently conducting or in the future plans to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes more regulated, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from our reserves. It is anticipated that federal, provincial and territorial regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While the Company is unable to predict the impact of any potential regulations upon our business and affairs, the implementation of new regulations with respect to water usage or hydraulic fracturing generally could increase our costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact our prospects, any of which may have a material adverse effect on our business, financial condition and results of operations.

British Columbia requires mandatory public disclosure of hydraulic fracturing fluid ingredients under the *Drilling and Production Regulation* and the provincial government has an online registry providing public access to information on fractured well locations and hydraulic fracturing fluid ingredients. In Alberta, the AER has issued multiple directives relating to hydraulic fracturing operations. AER Directive 083: *Hydraulic Fracturing - Subsurface Integrity* requires licensees to demonstrate that operational risks have been considered in the selection and design of wellbore construction and that licensees monitor and test such wellbores to ensure that well integrity is maintained. It also subjects licensees conducting hydraulic fracturing above or within 100 metres below the base of groundwater protection to conduct a risk assessment. AER Directive 059: W*ell Drilling and Completion Data Filing Requirements* requires disclosure of hydraulic fracturing fluid composition and water source data on a well-to-well basis within 30 calendar days from conclusion of an operation. In addition, due to seismic activity reported in some active oil and gas areas of Alberta, the AER has implemented seismic monitoring and reporting requirements for hydraulic fracturing operators in the certain zones in such areas.

Additionally, the Federal Government and certain Canadian provincial governments continue to review certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. In particular, a scientific study commissioned by the British Columbia government regarding the environmental impacts of hydraulic fracturing for oil and gas in British Columbia found the regulatory framework to be robust, while also identifying areas for improvement. However, certain environmental and other groups have suggested that additional federal, provincial, territorial and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources.

Further, certain governments in jurisdictions where we do not currently operate have considered or implemented moratoriums on hydraulic fracturing pending further study, and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs or third party or governmental claims, and could increase our cost of compliance and doing business as well as reduce the amount of natural gas and oil that we are ultimately able to produce from our reserves.

Although the Company cannot predict with any degree of certainty the total impact of potential future regulations upon our business and affairs, it is possible that we could face increased operating costs or curtailment of production in order to comply with legislation governing emissions and hydraulic fracturing.

Seismicity

Seismicity events have been recorded as occurring at the same time that the Company has been conducting hydraulic fracturing and related operations. Although the size of these events is considered light, they raise stakeholder and regulatory concerns. In addition, if monitoring seismicity becomes more regulated, our fracturing activities could become subject to additional permitting requirements and result in delays as well as potential increases in costs. Restrictions on hydraulic fracturing due to a perceived correlation to seismicity could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves in the affected areas.

Greenhouse Gas Emissions

The Company is subject to various GHG emissions-related legislation and monitors GHG emissions-related legislative developments in all jurisdictions in which we operate. Some provinces in which the Company operates have implemented carbon pricing mechanisms that meet or exceed the current federal benchmark carbon price of $30 per tonne (2020), which will increase $10 per tonne annually until it reaches $50 per tonne in 2022, at which point the price will rise by $15 per tonne each year until the price on carbon reaches $170 per tonne in 2030. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, potential new or additional GHG legislation and associated compliance costs, in particular in association with the adoption of the Paris Agreement under the UNFCCC, may have a material impact on the Company. See "*Industry Conditions - Climate Change Regulation*" in this AIF.

Draft regulations for the Clean Fuel Standard (the "Clean Fuel Regulations") were released in December 2020 and were open for public comment until March 3, 2021. As proposed, the Clean Fuel Regulations only apply to liquid fuels, not gaseous and solid fuels, and will apply to producers or importers of gasoline, diesel, kerosene and light and heavy fuel oils. The Clean Fuel Standard in its final form could impose additional costs to the Company's operations, which may have a material adverse effect on the Company's results of operations. The Federal Government has indicated that Spring 2022 is being targeted for publication of the final Clean Fuel Regulations.

Current GHG emissions legislation does not result in material compliance costs, but compliance costs may increase in the future as the federal benchmark carbon price rises in accordance with the GGPPA and may impact our operations and financial results. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact of such matters on our operations and financial condition at this time.

Environmental and Decommissioning Liabilities

Despite our implementation of health, safety and environmental standards, there is a risk that accidents or regulatory non-compliance can occur, the outcomes of which, including remedial work or regulatory intervention, cannot be foreseen or planned for. The Company expects to incur site restoration costs over a prolonged period as existing fields are depleted. The process of estimating decommissioning liabilities is complex and involves significant uncertainties concerning the timing of the decommissioning activity; legislative changes; technological advancement; regulatory, environmental and political changes; and the appropriate discount rate used in estimating the liability. Any change to these assumptions could result in a change to the decommissioning liabilities to which we are subject. In addition, particularly with respect to operations for which the Company is not the operator and may not determine cost estimates or the timing of decommissioning, cost overruns are possible. Moreover, the Company is often jointly and severally liable for the decommissioning costs associated with our various operations and could, therefore, be required to pay more than its net share.

Alberta and British Columbia have 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 our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. Separately, any changes to the values used to calculate each industry participant's share of the total decommissioning liabilities may also result in increases to the security that must be posted.

Following the SCC's decision in Redwater (the "**Redwater SCC Decision**"), oil and gas enterprises that become insolvent will generally be required to apply the value of any remaining assets to satisfy the liabilities associated with their abandonment and reclamation obligations in priority to the claims of secured and unsecured creditors. It is not yet clear how market participants will respond to the Redwater SCC Decision. The decision is, however, anticipated to reduce credit availability and increase the cost of credit for oil and gas enterprises with relatively high levels of abandonment and reclamation obligations within their asset bases. It may also cause creditors to impose additional covenants on borrowers with respect to compliance with their abandonment and reclamation obligations.

The Redwater proceedings also resulted in changes to the regulatory regimes in Alberta and British Columbia. In response to the Redwater decision at the Alberta Court of Queen's Bench, the AER released Bulletin 2016-16 which, among other things, implemented important changes to the AER’s procedures relating to liability management ratings, licence eligibility and licence transfers. In addition, changes with respect to licence eligibility were codified in amendments to AER Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*. Among other things, Directive 067 provided the AER with broad discretion to determine if a party poses an "unreasonable risk" such that it should not be eligible to hold AER licences.

The Government of Alberta also announced amendments to Directive 006: Licensee Liability Rating (LLR) Program and a new Directive 088: Licensee Life-Cycle Management, introducing a more comprehensive assessment of corporate health that considers a wider variety of factors than those considered under the Alberta LLR program and establishing clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects.

The Government of British Columbia has announced similar policies following the Redwater proceedings. In particular, the Liability Management Program in British Columbia determines if a permit holder is high risk and is required to pay a security deposit. In May of 2019, the BCOGC introduced the *Dormancy and Shutdown Regulation*, introducing mandatory timelines for oil and gas site remediation. See "*Industry Conditions - Liability Management Rating Programs*" in this AIF.

These changes may impact the Company’s ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to, or the abandonment of, projects and transactions. As a result of the current economic environment, the number of orphaned wells in Alberta and British Columbia has increased significantly and, accordingly, the aggregate value of the abandonment and reclamation liabilities assumed by the OWA in Alberta and the OSRF in British Columbia has increased and may continue to increase. While the Redwater SCC Decision may reduce the abandonment and reclamation liabilities ultimately assumed by the OWA and the OSRF in the long-term, their abandonment and reclamation liabilities will remain at elevated levels until a significant number of orphaned wells are decommissioned. As a result, the OWA and the OSRF may seek additional 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 SCC 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, our business, financial condition, results of operations and cash flows.

LEGAL PROCEEDINGS

In March 2001, a predecessor of PPR Canada acquired interests in certain heavy oil assets in the Eyehill Creek area of Alberta from certain predecessors of Encana Corporation. In 2003, IFP Technologies (Canada) Inc. ("**IFP**") commenced an action in the Court of Queen's Bench of Alberta against Encana Corporation and certain of its predecessors and affiliates and against certain predecessors of PPR Canada, claiming, among other things, $45.6 million in damages for breach of contract and lost opportunity or, alternatively, an accounting of 20% of the net revenue from primary production conducted by PPR Canada's predecessors from the acquired properties. At the outset of the trial in 2011, IFP amended its claim to increase the damages sought to $56.7 million, plus interest and costs. In a decision issued in 2014, the Court of Queen's Bench of Alberta ruled in favour of the defendants and dismissed IFP's claim. IFP subsequently appealed the trial decision to the Court of Appeal of Alberta, challenging the lower court's findings on liability and its provisional assessment of damages. The appeal was heard in the fourth quarter of 2015. In May 2017, in a two-to-one majority decision, the Court of Appeal allowed the appeal and held that IFP has a 20% working interest in the Eyehill Creek properties. The Court found that IFP is entitled to an accounting for its proportionate share of the net revenue realized from primary production at Eyehill Creek, and remitted the calculation of net revenue to the Court of Queen's Bench for determination. In August 2017, the defendants applied to the SCC for leave to appeal the Court of Appeal decision. In April 2018, the SCC refused leave to appeal, with the result that IFP is, pursuant to the Court of Appeal decision, entitled to an accounting for profits from the affected properties from 2002 forward. Although the final outcome of this case remains uncertain in light of the calculation issues left unresolved by the Court of Appeal decision and sent back to the Court of Queen's Bench for further determination, on the available facts the Company does not expect the ultimate disposition of the matter to have a material effect on its business. A trial on the unresolved issues is scheduled to be heard in June 2022.

In September 2013, LPRI commenced arbitration proceedings under the North American Free Trade Agreement ("**NAFTA**") against the Government of Canada for actions taken by the Government of Quebec in 2011 to cancel, without compensation, oil and gas mining rights under a portion of the Saint Lawrence River - including an exploration permit covering 33,460 acres previously held by LPR Canada. LPRI believes that the cancellation was a violation of NAFTA by Quebec, including Articles 1105 (Minimum Standard of Treatment) and 1110 (Expropriation) thereof, for which the Federal Government is responsible, and seeks monetary damages to compensate for its sunk costs and lost development opportunity. The Government of Canada defended the claim. A 10-day hearing before a NAFTA tribunal was held in October 2017 with closing arguments heard in November 2017. A new tribunal chair was appointed in late 2020 following the unexpected death of the original chair, and a further two-day hearing was completed in February 2021. The parties continue to await the tribunal's decision. There can be no assurance as to the outcome of the proceedings, either with respect to the tribunal's conclusions on the substantive merits of the claim or any determination of compensation thereunder.

The Company is and was not during 2021 otherwise a party to, and its property is and was not during 2021 otherwise the subject of, any legal proceedings that involves a claim for damages (exclusive of interest and costs) in an amount greater than 10% of the Company's current assets, and the Company does not know of any such legal proceeding to be contemplated.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed in this AIF, no director, executive officer, or person or company that beneficially owns or controls or directs, directly or indirectly, more than 10% of the Common Shares, nor any associate or affiliate of the foregoing, has any material interest, direct or indirect, in any transaction within the three most recently completed financial years of the Company or during the current financial year, that has materially affected or that would materially affect the Company.

TRANSFER AGENT AND REGISTRAR

Alliance Trust Company, Calgary, Alberta, is the appointed transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

Neither Prairie Provident nor any of its subsidiaries is a party to any contract entered into outside of the ordinary course of business that is material to the Company.

INTERESTS OF EXPERTS

No person or company whose profession or business gives the authority to a report, valuation, statement or opinion prepared or certified by it, which is described, included or referred to in a filing made by Prairie Provident under NI 51-102 during, or relating to, its most recently completed financial year, other than Ernst & Young LLP, our independent auditor, and Sproule, our independent qualified reserves evaluator under NI 51-101.

The designated professionals of Sproule as a group, at the time of preparing its report, held less than 1% of any class of outstanding securities of Prairie Provident or its associates or affiliates, confirmed in the signed certificates included in the report titled *Evaluation of the P&NG reserves of Prairie Provident Resources Inc. (as of December 31, 2021),* and thereafter none received or is to receive any registered or beneficial interest, direct or indirect, in any securities or other property of Prairie Provident or any of its associates or affiliates.

Ernst & Young LLP has advised they are independent with respect to the Company in the context of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to Prairie Provident is filed under the Company's issuer profile on SEDAR at www.sedar.com, including financial information provided in its comparative annual financial statements and management's discussion and analysis for the year ended December 31, 2021. In addition, information regarding remuneration and compensation of the Company's directors and officers, principal shareholders and securities authorized for issuance under equity compensation plans, is contained in the information circular for the most recent meeting of Prairie Provident shareholders involving the election of directors.

SCHEDULE A

**REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR**

(FORM 51-101F2)

(attached)

Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Prairie Provident Resources Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, 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, 2021	Canada				
Total			**Nil**	**414,210**	**Nil**	**414,210**

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

7. We have no responsibility to update our 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 Prairie Provident Resources Inc. (As of December 31, 2021)".

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

[stamp of Tamara Warren – Professional Engineer Alberta]

Jan 17, 2022
Tamara Warren, P.Eng.
Petroleum Engineer

Sproule Associates Limited
APEGA Permit Number 00417

(signed) "Douglas McNichol"
____

Douglas McNichol, P.Eng.
Senior Manager, Engineering
Date: Jan. 17, 2022

(signed) "Alec Kovaltchouk"
____

Alec Kovaltchouk, P.Geo.
VP, Geoscience
Date: Jan. 17, 2022

SCHEDULE B

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

(FORM 51-101F3)

(attached)

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Prairie Provident Resources Inc. (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, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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 evaluator;

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

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

DATE: March 29, 2022

(signed) "Remi Berthelet"	*(signed) "Mimi Lai"*
Remi Berthelet	Mimi Lai
President and Chief Executive Officer	Executive VP Finance and Chief Financial Officer
(signed) "Patrick McDonald"	*(signed) "Derek Petrie"*
Patrick McDonald	Derek Petrie
Director	Director

SCHEDULE C

AUDIT COMMITTEE CHARTER

(attached)

PRAIRIE PROVIDENT RESOURCES INC.

AUDIT COMMITTEE CHARTER

This Charter of the Audit Committee (the "Committee") of the board of directors (the "Board") of Prairie Provident Resources Inc. (the "Corporation") is adopted by the Board as of September 13, 2016.

A. Purpose

The Board has established the Committee for the principal purpose of assisting the Board in fulfilling its oversight responsibilities regarding (i) the integrity of the Corporation's financial statements and related accounting, financial reporting and audit processes, (ii) internal accounting and financial control systems and procedures, and disclosure controls and procedures, (iii) the qualification and performance of the Corporation's independent auditors ("Auditor"), and (iv) the Corporation's risk management strategies, and compliance by the Corporation with applicable legal requirements relating thereto.

While the Committee has the responsibilities set forth in this Charter, the role of the Committee is one of oversight and counsel. It is not the duty of the Committee to assure the Corporation's compliance with legal or regulatory requirements or corporate policies, or to assume the responsibilities of management of the Corporation ("Management"). In particular, the Committee is not responsible for planning or conducting financial audits or determining that the Corporation's financial statements are complete and accurate and in accordance with International Financial Reporting Standards ("IFRS"), or for planning or conducting audits. These matters are the responsibility of Management and the Auditor.

The Committee is authorized to conduct or authorize investigations into any matter that is within the scope of the powers and responsibilities delegated to the Committee, with full and unrestricted access to all books, records, facilities and personnel of the Corporation and its subsidiaries and (without limiting Part D of this Charter) the authority to engage and instruct independent counsel and such accounting and other advisors as it determines necessary or appropriate to perform its responsibilities.

B. Composition

The Committee shall consist of at least three (3) members of the Board, all of whom shall be independent under applicable securities laws pertaining to audit committees. All Committee members must also be financially literate, as determined by the Board in its business judgment, and satisfy all other requirements of applicable corporate and securities laws and stock exchange requirements regarding audit committee membership. Determinations as to whether the appointment of any particular director to the Committee meets applicable qualification criteria shall be made by the Board.

The Board shall annually appoint the members of the Committee and designate one such member to serve as Chair of the Committee, and in connection therewith review and confirm their independence and qualification.

C. Responsibilities

In furtherance of its purpose the Committee shall have the following responsibilities, and in addition to the activities specifically described in this Charter may conduct such activities incidental thereto that the Committee determines to be appropriate or as may otherwise be delegated to it from time to time by the Board:

Financial Reporting and Disclosure

- review, with Management and the Auditor, the Corporation's compliance with applicable legal and regulatory requirements regarding financial reporting and disclosure;

- review, with Management and the Auditor, significant accounting and financial reporting practices of the Corporation and related disclosure issues, including with respect to complex or unusual transactions, judgment areas such as reserves or estimates, and significant changes to accounting principles or policies, with a view to obtaining reasonable assurance as to the appropriateness of the Corporation's accounting and financial reporting practices and the fair presentation of the Corporation's financial statements in accordance with IFRS;

- review, with Management and the Auditor, their views on the appropriateness and quality (versus bare acceptability) of the Corporation's accounting principles and the degree of aggressiveness or conservatism of its accounting principles and underlying estimates;

- review, with Management and the Auditor, the identification of, accounting for and disclosure of transactions, arrangements and/or relationships with related parties;

- review new or proposed developments in accounting and financial reporting standards, or related legal or regulatory requirements, that could reasonably be expected to affect the Corporation;

- review, with Management and the Auditor, actual or anticipated litigation, contingencies or other events that could reasonably be expected to materially affect the Corporation's financial statements, and their disclosure in the financial statements;

- review, with Management and the Auditor, any "off-balance sheet" transactions or arrangements with unconsolidated entities or other persons, or that may have a material effect on the Corporation's financial statements;

- satisfy itself that adequate procedures are in place for review of the Corporation's external disclosure of financial information extracted or derived from the Corporation's financial statements, and periodically assess the adequacy of those procedures;

- review, with the Chief Executive Officer and Chief Financial Officer of the Corporation, the procedures undertaken in connection with any required certifications provided by such officers in respect of the annual or interim financial statements of the Corporation and any related management's discussion and analysis ("MD&A") or similar disclosure documents;

- review the annual and interim financial statements and any related MD&A with Management and the Auditor prior to the filing of such documents with applicable regulatory authorities or their public dissemination, and make recommendations to the Board regarding the approval of such documents;

- review earnings news releases (paying particular attention to any non-IFRS information contained therein) and any financial information or earnings guidance provided to analysts or rating agencies;

Internal Controls

- at least annually, review with Management and the Auditor the adequacy and effectiveness of the Company's accounting and financial control systems and procedures, and elicit recommendations for improvement;

- review, with Management, the Auditor and any third party engaged to provide advice on the subject, the design, evaluation, effectiveness and integrity of the Corporation's internal controls over financial reporting and disclosure controls and procedures;

- review any conclusions or analyses of Management, the Auditor and any third party engaged to provide advice on the subject, whether in connection with a certification process in respect of the annual or interim financial statements of the Corporation or otherwise, regarding the effectiveness of the Corporation's internal controls over financial reporting or disclosure controls and procedures, and any material weakness or deficiency relating to the design or operation of internal controls, and Management's response to any identified weakness or deficiency;

- obtain reasonable assurance from Management as to the payment by the Corporation to appropriate governmental authorities of all amounts required by applicable laws, including withholding taxes;

- review and oversee the investigation of any allegation of fraud, illegality or other impropriety against or otherwise involving Management or other personnel who have a role in the Corporation's internal controls, or relating in any way to the Corporation's financial position, accounting practices, internal controls, financial reporting or external disclosure;

- establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters;

- as applicable, review and approve the internal audit function (if any) for the Corporation, including with respect to scope, authority and internal reporting channels, and any annual audit plan and related budget and staffing requirements, and periodically meet with the personnel responsible for the internal audit function (if any) separately from Management;

- review any correspondence with governmental or regulatory authorities, any internal complaints and any published third party reports concerning the Corporation's financial position, accounting practices, internal controls, financial reporting or public disclosure;

Independent Auditors

- subject to requisite shareholder approvals, review and determine appointment or termination of the Auditor;

- review the independence, professional qualification and performance of the Auditor;

- oversee and approve (including by way of pre-approval with respect to non-audit services) all audit or non-audit engagements of the Auditor by the Corporation or any subsidiary, and approve the terms of engagement (including compensation);

- require that the Auditor report directly to the Committee;

- determine whether to pre-approve the provision of non-audit services by the Auditor to the Corporation or any subsidiary, and establish the scope and limits of any such pre-approval, with the Chair of the Committee having the delegated authority to grant such pre-approval on behalf of the Committee;

- in connection with any non-audit services to be provided by the Auditor, consider whether the provision of such services is compatible with the Auditor's independence;

- consider and resolve any disagreements or unresolved issues between Management and the Auditor;

- establish hiring policies regarding partners, employees and former partners and employees of the Corporation's current and former Auditors;

- review, with Management and the Auditor, the annual audit and quarterly review plans for the current year, including the scope thereof and procedures to be used;

- at the conclusion of each annual audit, review the audit directly with the Auditor and inquire into any problems or difficulties encountered, comments or recommendations of the Auditor, and Management responses;

- report the results of the annual audit to the Board;

- at least annually, obtain and review a report from the Auditor regarding: (i) its relationship(s) with the Corporation; (ii) its internal quality-control procedures; (iii) any material issues raised by its most recent internal quality-control review (or peer review), or by any inquiry or investigation by governmental or professional authorities, within the preceding 5 years, respecting one or more independent audits carried out by the Auditor, and any steps taken to deal with any such issues;

- review all material written communications between the Auditor and the Corporation, including any post-audit or management letter containing the recommendations of the Auditor, Management's response, and subsequent follow up on any identified weakness;

- at least once per fiscal quarter meet with responsible Management and the Auditor, together and also separately, to discuss and obtain feedback with respect to the annual audit or interim review process generally, significant accounting policies, alternatives discussed with Management, any preferences of the Auditor as between available alternatives, any restrictions or limitations imposed by Management or otherwise experienced by the Auditor, Management's response to any proposed adjustments identified by the Auditor, any disagreements or unresolved issues, the Auditor's evaluation of the Corporation's financial and accounting personnel, issues and concerns generally, and any other matters raised by Management, the Auditor or any Committee member;

- obtain reasonable assurance as to compliance by the Auditor with any applicable legal or professional requirements regarding partner rotation;

Risk Management

- review, with Management and the Auditor, the Corporation's assessment of its major financial risk exposures and the steps taken by Management to monitor and manage such exposures;

- review the Corporation's risk management policies and procedures concerning its principal business risks, and discuss with Management the Corporation's significant risk exposures and steps taken to monitor and mitigate such exposures;

- review the Corporation's commodity price, financial and credit risk management activities, including oil and natural gas, foreign currency and interest rate hedging activities and the use of derivative instruments;

- review the Corporation's insurance program;

- review, through discussions with Management, the Auditor and appropriate advisors, the Corporation's compliance with applicable legal or regulatory requirements and internal policies and procedures;

- review any completed or proposed related party transactions involving the Corporation or any subsidiary, including with respect to actual and potential conflicts of interest and appropriate approval processes;

Other

- maintain free and open communication among and between the Committee, the Board, the Auditor and Management;

- regularly review with Management any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with legal or regulatory requirements, and performance and independence of the Auditor;

- review reports and analyses prepared by the Auditor and Management with respect to any matters contemplated by this Charter;

- report to the Board on Committee activities (including review of any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with legal or regulatory requirements or the performance and independence of the Auditor) and make recommendations to the Board regarding any of the matters described in this Charter;

- develop and recommend to the Board such corporate policies as the Committee may from time to time determine to be appropriate in furtherance of its responsibilities;

- facilitate direct communication to the Committee, through the Chair of the Committee, by the Auditor and the internal auditor (if any);

- conduct an annual evaluation of the Committee's performance of its responsibilities under this Charter, and report to the Board on such evaluation and its results; and

- periodically review (at least annually) this Charter and any approved position description for the Chair of the Committee, including in light of any changes in law or updated regulatory guidance, and recommend to the Board such revisions (if any) as the Committee may determine to be appropriate.

Notwithstanding the responsibilities described herein, nothing in this Charter is intended to create, or shall be construed as creating, any personal duty or liability on the part of any Committee member or other director of the Corporation, beyond those duties and liabilities specifically provided for under applicable law.

D. Administrative Matters

- Meetings. The Committee shall meet on a regularly-scheduled basis at least four (4) times per year, and on such other occasions as the members of the Committee may from time to time determine or as the Board Chair or Chief Executive Officer of the Corporation may request. Unless otherwise specified in the articles or by-laws of the Corporation or this Charter, the time and place for Committee meetings, and the procedure for calling and holding such meetings, shall be determined by the Committee.

- Quorum. A majority of Committee members, present in person, or participating by electronic means, telephone or other communication facilities that permit all persons participating in the meeting to hear each other, shall constitute a quorum at any meeting of the Committee. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains.

- Change of members. The Board may at any time and from time to time remove or replace any member of the Committee, and may fill any vacancy on the Committee.

- Term of appointment. Each Committee member shall hold office as such until the close of the next annual meeting of shareholders of the Corporation following the date of his or her appointment (or re-appointment, as applicable), or until he or she resigns, is replaced or for any reason ceases to be a director, whichever first occurs.

- Attendance by others. The Committee or the Chair may, in its discretion, invite such other directors, officers and employees of the Corporation, the Auditor, outside legal counsel and other advisors as it sees fit to attend at all or any portion of any Committee meeting. A director who attends a Committee meeting but is not a member of the Committee shall not be entitled to vote on any matter before the Committee.

- Chair. The Chair of the Committee shall preside at all Committee meetings (including in camera sessions); provided that for any meeting in respect of which the Chair is absent (or there is a vacancy in the position of Chair), the other Committee members may choose one of their number to act as Chair for that meeting. The Chair of the Committee shall approve the agenda for Committee meetings in consultation with the Board Chair, appropriate executive officers of the Corporation and, as considered appropriate by the Committee Chair, other directors. Any Committee member may request that additional items be included on the agenda for a Committee meeting.

- Notice to independent auditors. Notice of Committee meetings shall be given to the Auditor, who shall have the right to appear before and be heard at any Committee meeting.

- Meeting on request of independent auditors. The Chair of the Committee shall, upon the request of the Auditor, call a meeting of the Committee to consider any matter that the Auditor wishes to bring forward.

- Advisers. The Committee shall have the authority to engage, at the Corporation's expense, independent legal counsel and such other advisers of its choosing as it may, in its discretion, from time to time determine to be appropriate in the performance of its responsibilities, and to determine the terms of engagement. The fees and expenses of such independent legal counsel and other advisors will be subject to the approval of the Chair of the Committee and paid by the Corporation.

- Funding. The Corporation shall provide the Committee with such funding as the Committee may require to pay the fees and expenses of any independent legal counsel or other adviser engaged by the Committee, and any ordinary administrative expenses incurred by the Committee in the performance of its responsibilities.

- Access to information and personnel. Without limiting their rights as members of the Board to receive and have access to information concerning the Corporation, the Committee shall, in the performance of its responsibilities, have the right to: (i) inspect any and all books and records of the Corporation; (ii) directly contact (through the Chair of the Committee) and meet with any officer, employee or consultant of the Corporation or any of its subsidiaries, or the Auditor; and (iii) discuss with any such officer, employee or consultant, or the Auditor, the information contained in such books and records and any other information or matter that the Committee determines to be appropriate.

- In camera sessions. Unless the Committee determines it to be impracticable in respect of any particular meeting, the Committee members shall hold an in camera session without Management at each regular Committee meeting.

- Minutes. Minutes shall be kept of all Committee meetings.

- Delegation. The Committee shall have the authority, in its discretion and as permitted by applicable law, to delegate to its Chair, any one or more of its members, or any subcommittee it may choose to form, its responsibility for, and authority with respect to, any matter or matters contemplated by this Charter;

provided that unless expressly authorized by the Committee such delegated authority shall not include the authority to engage independent legal counsel or other experts or advisers.