PRAIRIE PROVIDENT RESOURCES

ANNUAL INFORMATION FORM

For the year ended December 31, 2023

April 2, 2024

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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 Prairie Provident Resources Canada Ltd. (formerly Lone Pine Resources Canada Ltd.) and its other wholly-owned subsidiaries. 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, 2023.

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 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;

"**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) and 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:	
bbl	barrel
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
NGLs	natural gas liquids

Natural Gas:	
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
Btu	British thermal unit
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

To Convert From	To	Multiply By
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 while exploiting low-risk production enhancement and drilling opportunities within the current asset portfolio.

Our business was previously conducted by Lone Pine Resources Inc. and its subsidiary, Lone Pine Resources Canada Ltd., 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. and Arsenal Energy Inc. (which combined in September 2016) and, upon its acquisition by Prairie Provident in November 2018, Marquee Energy Ltd.

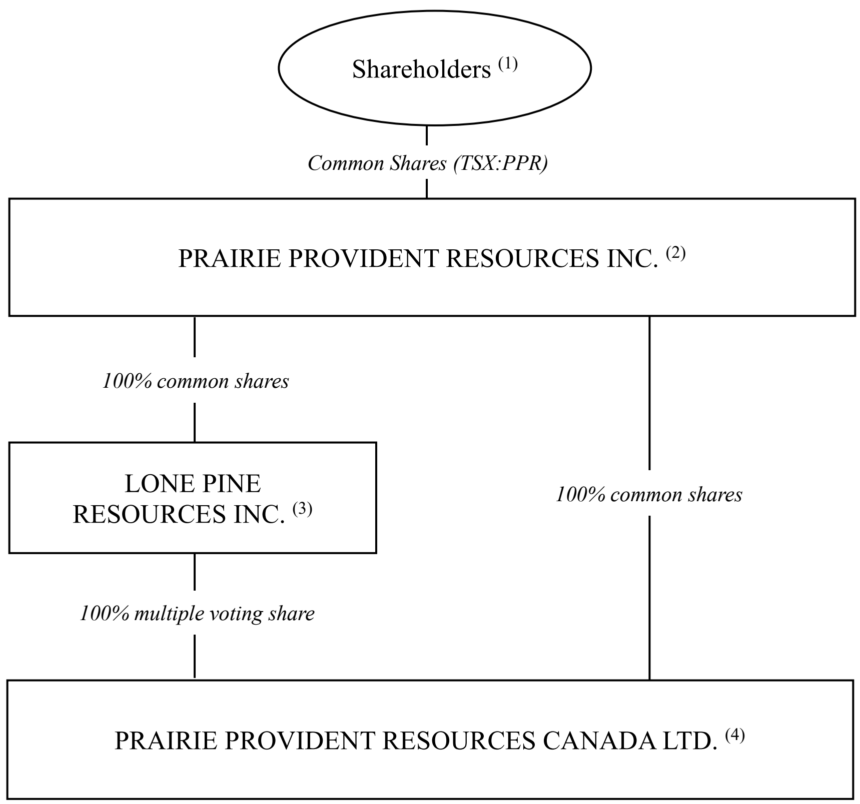
Our reserves, producing properties and principal exploration prospects are located in the Province of Alberta.

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 Lone Pine Resources Inc., which are its only material subsidiaries. The following diagram sets out the intercorporate ownership structure of Prairie Provident and its material subsidiaries.



Notes:

(1) Following completion of the Recapitalization described below under "– *General Development of our Business – Recapitalization*", approximately 75.6% of the outstanding Common Shares are held by PCEP Canadian Holdco, LLC, a Delaware limited liability company that is indirectly managed by PGIM Private Capital, a unit of PGIM, Inc.

(2) Alberta corporation.

(3) Delaware corporation that is a wholly-owned subsidiary of Prairie Provident and holds a controlling equity interest in Prairie Provident Resources Canada Ltd.

(4) 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 continued 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 and the Company's liquidity and capital resources, with the Company drilling 5 wells in 2021 and 3 wells in 2022. The Company did not drill any wells in 2023 as it continued its focus on refinancing.

The Company has financed its business since 2021 through internally generated cash flows, borrowings under credit arrangements and, more recently, capital raised in connection with the Recapitalization described below.

Prior to completion of the Recapitalization on May 16, 2023, the Company's credit arrangements were comprised of a senior secured revolving note facility (the "**First Lien Facility**"), and three series of senior subordinated notes ("**Subordinated Notes**") issued in 2017, 2018 and 2020, respectively.

On December 29, 2021, the note purchase agreements governing the First Lien Facility and the Subordinated Notes were further amended to, among other things, extend the maturity date of the First Lien Facility from December 31, 2022 to December 31, 2023, and the maturity date of the Subordinated Notes originally issued in 2017 and 2018 from June 30, 2023 to June 30, 2024. The maturity date of the Subordinated Notes issued in December 2020 was left unchanged at December 21, 2026.

Effective December 31, 2022, the borrowing base under the First Lien Facility was reduced to US$50.0 million in accordance with scheduled reductions agreed in December 2020.

Recapitalization

On March 29, 2023, Prairie Provident announced that it had entered into a Debt Restructuring Agreement with PCEP Canadian Holdco, LLC (the "**Former Noteholder**"), which held all then-outstanding Subordinated Notes as well as 34,292,360 warrants to purchase Common Shares exercisable at C$0.0192 per share (the "**Lender Warrants**"), and certain affiliates of the Former Noteholder, and agreements with certain other parties, for various recapitalization transactions (collectively, the "**Recapitalization**") to, among other things, raise additional equity and debt capital, significantly reduce the Company's total debt through a repayment of all outstanding Subordinated Notes with equity, waive certain defaults under the First Lien Facility and the Subordinated Notes, and extend the maturity date of the First Lien Facility.

The Former Noteholder is a Delaware limited liability company that is indirectly managed by PGIM Private Capital, a unit of PGIM, Inc.

The Recapitalization was subsequently completed, and included the following principal transactions:

- the issue and sale by Prairie Provident of second lien notes due December 31, 2024 (the "**Second Lien Notes**") in the principal amount of US$3.64 million (approximately C$5 million at the then-prevailing exchange rate) to certain affiliates of the Former Noteholder, which was completed on March 30, 2023;

- a brokered private placement offering of 44,444,444 units of Prairie Provident ("**Units**") at a price of C$0.09 per Unit for aggregate gross proceeds of C$4 million, each Unit being comprised of one Common Share and one warrant exercisable for an additional Common Share at an exercise price of C$0.10 per share for a 5-year term ending May 16, 2028 (the "**Equity Financing**"), which was completed on May 16, 2023;

- settlement of all the Company's indebtedness under the outstanding Subordinated Notes previously held by the Former Noteholder, in the aggregate amount of US$53.4 million (approximately C$72.0 million at the then-prevailing exchange rate), through the issuance on May 16, 2023 of 514,408,902 Common Shares at an agreed repayment price equal to C$0.14 per Common Share (the "**Subordinated Notes Settlement**");

- concurrently with the Subordinated Notes Settlement, a 'cashless' exercise by the Former Noteholder of the Lender Warrants, for an issuance of an additional 26,516,207 Common Shares (the "**Warrant Exercise**"); and

- amendments to the agreement governing the First Lien Facility to, among other things, waive certain defaults and extend the maturity date to July 1, 2024.

In connection with the Subordinated Notes Settlement, the Former Noteholder agreed to certain 'lock-up' restrictions pursuant to which it will not, without Prairie Provident's consent, dispose of Common Shares acquired by it pursuant to the Subordinated Notes Settlement, otherwise than in connection with a business combination, a reorganization or restructuring, or an acquisition of all or substantially all the Common Shares, or pursuant to a private sale, or to an affiliate or other related party. The lock-up restrictions ceased to apply as to 33⅓% of all such Common Shares on November 16, 2023 (being the 6-month anniversary of the Subordinated Notes Settlement) and will cease to apply as to a further 33⅓% of all such Common Shares on the 12-month and 18-month anniversaries, respectively.

Pursuant to an Investor Rights Agreement entered into in connection with completion of the Equity Financing and the Subordinated Notes Settlement, the Former Noteholder has the right to nominate and/or have appointed a majority of the Board of Directors. Glenn Hamilton, Dale Miller and Kathy Turgeon were subsequently nominated and became directors of Prairie Provident pursuant to the exercise of this right. See "*Directors and Officers*" below.

In addition to the warrants issued as part of the units sold in the Equity Financing, an aggregate of 3,555,555 broker warrants ("**Broker Warrants**") were issued as partial compensation to the agents for the Equity Financing. Each Broker Warrant entitles the holder to subscribe for and purchase one Unit at an exercise price of C$0.09 per Unit for a 5-year term ending May 16, 2028.

Immediately following completion of the Recapitalization – including, in particular, the Equity Financing, the Subordinated Notes Settlement, and the Warrant Exercise – there were 715,594,258 Common Shares outstanding (on a non-diluted basis), of which:

- 130,224,704 Common Shares (approximately 18.2%) were outstanding prior to the Recapitalization;

- 44,444,444 Common Shares (approximately 6.2%) were issued to subscribers under the Equity Financing; and

- 540,925,109 Common Shares (approximately 75.6%) were issued to the Former Noteholder pursuant to the Subordinated Notes Settlement and the Warrant Exercise.

After giving effect to the subsequent issue of 515,952 Common Shares pursuant to the settlement of restricted share units (RSUs) and the exercise of stock options, there are 716,105,903 Common Shares outstanding (on a non-diluted basis) on the date of this AIF, of which the Former Noteholder continues, to the Company's knowledge, to hold 540,925,109 Common Shares representing approximately 75.6% of the total.

Recent Developments

In October 2023, PPR Canada entered into agreements to sell its Evi assets in Northern Alberta and certain non-core assets located in the Provost area of Central Alberta. The sale transactions (together, the "**Dispositions**") were completed in early 2024, for net proceeds from the Evi disposition of $22.5 million after adjustments (based on an effective date of August 1, 2023) and net proceeds from the Provost disposition of $1.7 million after adjustments (based on an effective date of July 1, 2023).

The Company used $20,000,000 of the proceeds to retire indebtedness under the First Lien Facility. The First Lien Facility is fully drawn and no further borrowings are available thereunder.

Pursuant to the terms of the Provost sale, the buyer is conditionally required to pay up to a maximum of $720,000 in additional proceeds depending on WTI prices and production from the acquired Provost assets during the 24-month period ending March 2026, as follows: (i) $10,000 for any month that WTI averages between USD $80.00 and $89.99; (ii) $20,000 for any month that WTI averages between USD $90.00 and $99.99; and (iii) $30,000 for any month that WTI averages USD $100 or more – in each case prorated for any month in which production from the acquired Provost assets is less than 70 boe/d.

The reserves data estimates of the Company's proved reserves and probable reserves and related future net revenue set out below under "*Statement of Reserves Data and Other Oil and Gas Information*" are as at an effective date of December 31, 2023. As the Dispositions did not close until after the effective date, the corporate reserves data of Prairie Provident evaluated in the Sproule Report (as defined below) includes reserves data attributed to the Evi and Provost properties that were sold in the Dispositions (the "**Sold Properties**").

The following tables set out information regarding (i) the reserves data attributed to the Sold Properties as at December 31, 2023 in the Sproule Report, and (ii) the Company's total reserves data as at December 31, 2023 based on the Sproule Report, calculated on a *pro forma*, post-Dispositions basis, by deducting the reserves data attributed to the Sold Properties as if the Dispositions had been completed on December 31, 2023. This information must be read together with the further information set out below under "*Statement of Reserves Data and Other Oil and Gas Information*".

SOLD PROPERTIES

Summary of Oil and Gas Reserves as of December 31, 2023

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	2,761	2,488	-	-	1,324	1,255	-	-	19	17	3,001	2,713
Developed Non-Producing	1,737	1,452	-	-	215	204	-	-	3	2	1,776	1,489
Producing Undeveloped	1,469	1,338	-	-	375	356	-	-	6	5	1,537	1,403
TOTAL PROVED	5,968	5,278	-	-	1,914	1,815	-	-	28	24	6,315	5,605
PROBABLE	2,049	1,723	-	-	783	736	-	-	12	10	2,192	1,856
TOTAL PROVED PLUS PROBABLE	8,017	7,000	-	-	2,698	2,551	-	-	40	35	8,506	7,461

SOLD PROPERTIES

Summary of Net Present Values of Future Net Revenue as of December 31, 2023

Forecast Prices and Costs

(Before and After Income Taxes)

	Net Present Values of Future Net Revenue ($000s)										Unit Value (1) Before Income Taxes – Discounted at 10%/year
	Before Income Taxes – Discounted at (%/year)					After Income Taxes – Discounted at (%/year)					
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**$/boe**
PROVED											
Developed Producing	37,713	69,951	62,861	54,114	47,134	37,713	69,951	62,861	54,114	47,134	23.17
Developed Non-Producing	97,305	53,584	34,345	23,817	17,328	97,305	53,584	34,345	23,817	17,328	23.07
Producing Undeveloped	51,182	38,557	29,254	22,401	17,270	51,182	38,557	29,254	22,401	17,270	20.86
TOTAL PROVED	186,199	162,092	126,460	100,331	81,732	186,199	162,092	126,460	100,331	81,732	22.56
PROBABLE	107,366	69,967	50,220	38,337	30,557	107,366	69,967	50,220	38,337	30,557	27.06
TOTAL PROVED PLUS PROBABLE	293,565	232,059	176,680	138,669	112,289	293,565	232,059	176,680	138,669	112,289	23.68

Note:

(1) Unit values are based on net reserves.

PRAIRIE PROVIDENT PRO FORMA – POST-DISPOSITIONS

Summary of Oil and Gas Reserves as of December 31, 2023

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	2,623	2,259	366	314	18,497	16,617	221	197	304	253	6,413	5,629
Developed Non-Producing	444	392	—	—	1.991	1,843	—	—	38	31	814	730
Producing Undeveloped	4,684	4,068	282	282	14,328	13,161	—	—	227	197	7,582	6,692
TOTAL PROVED	7,751	6,719	649	547	34,816	31,620	221	197	568	482	14,808	13,050
PROBABLE	3,655	2,939	513	428	14,513	13,052	58	51	232	190	6,829	5,741
TOTAL PROVED PLUS PROBABLE	11,407	9,658	1,162	975	49,328	44,672	279	249	800	672	21,637	18,792

PRAIRIE PROVIDENT PRO FORMA – POST-DISPOSITIONS

Summary of Net Present Values of Future Net Revenue as of December 31, 2023

Forecast Prices and Costs
(Before and After Income Taxes)

	Net Present Values of Future Net Revenue ($000s)										Unit Value [(1)] Before Income Taxes – Discounted at 10%/year
	Before Income Taxes – Discounted at (%/year)					After Income Taxes – Discounted at (%/year)					
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**$/boe**
PROVED											
Developed Producing	(20,613)	52,675	55,208	49,795	44,380	(20,613)	52,675	55,208	49,795	44,380	9.81
Developed Non-Producing	27,797	17,927	12,948	10,011	8,082	27,797	17,927	12,948	10,011	8,082	17.73
Producing Undeveloped	230,531	159,964	116,114	87,289	67,197	230,531	159,964	116,114	87,289	67,197	17.35
TOTAL PROVED	237,715	230,566	184,270	147,095	119,659	237,735	230,566	184,270	147,095	119,659	14.12
PROBABLE	268,255	175,617	129,250	102,072	84,310	230,462	158,698	121,201	98,042	82,202	22.51
TOTAL PROVED PLUS PROBABLE	505,971	406,183	313,520	249,167	203,969	468,177	389,264	305,472	245,137	201,861	16.68

Note:

(1) Unit values are based on net reserves.

For the quarter ended December 31, 2023, total production from the Sold Properties averaged approximately 912 boe/d, comprised of approximately 835 bbls/d of light and medium crude oil, 5 bbls/d of NGLs, and 433 Mcf/d of conventional natural gas.

Business Plan and Strategy

We are committed to capital discipline and operational efficiency, with a focus on development opportunities in our Central and Southern Alberta core areas and improving profitability through operating cost improvements. Our strategy is to optimize cash flow from our existing assets while exploiting low-risk production enhancement and drilling opportunities within the current asset portfolio.

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, see Note 23 (Commitments and Contingencies) in the Company's annual financial statements for the year ended December 31, 2023, available on Prairie Provident's website at www.ppr.ca and under its issuer profile on SEDAR+ at www.sedarplus.ca.

Employees

As of December 31, 2023, the Company had 20 full-time employees and 65 contractors (both full-time and part-time). 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 February 7, 2024 prepared by Sproule Associates Limited ("**Sproule**") evaluating the crude oil, natural gas and NGLs reserves of the Company as at an effective date of

December 31, 2023 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, 2023 was considered in its preparation, was February 7, 2024. 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 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, 2023, as evaluated by Sproule using forecast prices and costs.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2023

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	5,384	4,747	366	314	19,821	17,871	221	197	323	270	9,414	8,342
Developed Non-Producing	2,182	1,844	—	—	2,205	2,047	—	—	40	34	2,590	2,219
Producing Undeveloped	6,153	5,406	282	233	14,703	13,517	—	—	233	203	9,119	8,094
TOTAL PROVED	13,719	11,997	649	547	36,730	33,435	221	197	596	506	21,123	18,655
PROBABLE	5,705	4,662	513	428	15,296	13,787	58	51	244	201	9,020	7,597
TOTAL PROVED PLUS PROBABLE	19,424	16,659	1,162	975	52,027	47,222	279	249	840	707	30,143	26,252

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE as of December 31, 2023

FORECAST PRICES AND COSTS
(Before and After Income Taxes)

	Net Present Values of Future Net Revenue ($000s)										Unit Value [1] Before Income Taxes – Discounted at 10%/year
	Before Income Taxes – Discounted at (%/year)					After Income Taxes – Discounted at (%/year)					
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**$/boe**
PROVED											
Developed Producing	17,100	122,627	118,070	103,909	91,513	17,100	122,627	118,070	103,909	91,513	14.15
Developed Non-Producing	125,102	71,512	47,293	33,828	25,410	125,102	71,512	47,293	33,828	25,410	21.31
Producing Undeveloped	281,713	198,521	145,368	109,690	84,468	281,713	198,521	145,368	109,690	84,468	17.96
TOTAL PROVED	423,915	392,659	310,730	247,426	201,391	423,915	392,659	310,730	247,426	201,391	16.66
PROBABLE	375,621	245,583	179,469	140,409	114,867	337,827	228,664	171,421	136,379	112,759	23.63
TOTAL PROVED PLUS PROBABLE	799,536	638,242	490,200	387,836	316,258	761,742	621,323	482,151	383,806	314,150	18.67

Note:

(1) Unit values are based on net reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2023

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 Revenue After Income Taxes
TOTAL PROVED	1,671,420	203,296	630,805	163,963	249,442	423,915	—	423,915
TOTAL PROVED PLUS PROBABLE	2,438,861	330,654	845,656	209,198	253,817	799,536	37,794	761,742

Notes:

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

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

FUTURE NET REVENUE BY PRODUCTION GROUP as of December 31, 2023

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]	266,775	17.02
	Heavy Crude Oil [1]	21,808	33.05
	Conventional Natural Gas [2]	21,824	9.55
	Coal Bed Methane [3]	323	8.90
	Total Proved	310,730	

		Future Net Revenue Before Income Taxes (4) (discounted at 10%/year)	
Reserves Category	**Production Type**	**$000s**	**$/boe**
TOTAL PROVED PLUS PROBABLE	Light and Medium Crude Oil (1)	425,727	19.28
	Heavy Crude Oil (1)	38,058	32.03
	Conventional Natural Gas (2)	26,044	8.87
	Coal Bed Methane (3)	371	8.11
	Total Proved Plus Probable	490,200	

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 and completing 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 and are expected to be developed within a limited time.

(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, 2023.

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, 2023. 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)**

Year	WTI [(1)]	Canadian Light Sweet [(2)]	Western Canada Select [(3)]	AECO-C (NIT) Spot	Edmonton Propane	Edmonton Butane	Edmonton Condensate (Pentanes Plus)	Operating Costs	Capital Costs	Exchange Rate
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/MMBtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	(%/Year)	(%/Year)	($US/$Cdn)
Historical										
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	-5.2%	-5.2%	0.75
2021	67.91	80.31	68.73	3.64	43.39	51.64	85.88	4.1%	7.9%	0.80
2022	94.23	119.75	98.51	5.43	50.11	61.68	121.28	9.4%	12.0%	0.77
2023	77.63	99.87	79.53	2.64	29.59	45.62	102.80	5.0%	5.0%	0.74
Forecast										
2024	76.00	97.33	81.33	2.33	28.21	50.67	101.33	0.0%	0.0%	0.75
2025	76.00	97.25	84.67	3.64	33.03	50.67	101.33	2.0%	2.0%	0.75
2026	76.00	97.17	84.33	3.95	32.78	50.67	101.33	2.0%	2.0%	0.75
2027	77.52	99.12	86.02	4.03	33.44	51.68	103.36	2.0%	2.0%	0.75
2028	79.07	101.10	87.74	4.11	34.11	52.71	105.43	2.0%	2.0%	0.75
2029	80.65	103.12	89.50	4.19	34.79	53.77	107.54	2.0%	2.0%	0.75
2030	82.26	105.18	91.29	4.27	35.48	54.84	109.69	2.0%	2.0%	0.75
2031	83.91	107.29	93.11	4.36	36.19	55.94	111.88	2.0%	2.0%	0.75
2032	85.59	109.43	94.97	4.44	36.92	57.06	114.12	2.0%	2.0%	0.75
2033	87.30	111.62	96.87	4.53	37.66	58.20	116.40	2.0%	2.0%	0.75
Thereafter	Escalation rate on prices and costs of +2.0% per year									

Notes:

(1) West Texas Intermediate (WTI) at Cushing Oklahoma (40º API)

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

(3) Western Canada Select at Hardisty, Alberta (20.5º API)

The weighted average historical prices realized by the Company for the year ended December 31, 2023 were $88.93 per bbl for light and medium crude oil, $82.50 for heavy crude oil, $2.55 per Mcf for natural gas and $53.05 per bbl for NGLs. For further information regarding the Company's production mix in 2023, 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, 2023 to the prior year's estimates, based on forecast prices and costs, by principal product type.

	Light and Medium Crude Oil			Heavy Crude Oil			Conventional Natural Gas		
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)
Dec 31, 2022 (1)	14,001	6,011	20,012	667	549	1,216	40,297	17,150	57,447
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	—	—	—	—	—	—	—	—	—
Infill Drilling	—	—	—	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	(6)	(1)	(7)
Economic Factors	52	20	72	1	2	2.2	(66)	(76)	(142)
Technical Revisions (2)	412	(326)	86	34	(38)	(4)	(762)	(1,779)	(2,541)
Production	(746)	—	(746)	(53)	—	(53)	(2,734)	—	(2,734)
Dec 31, 2023 (3)	13,719	5,705	19,424	649	513	1,162	36,729	15,294	52,023

	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)
Dec 31, 2022 (1)	316	80	397	700	291	991	22,138	9,723	31,861
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	—	—	—	—	—	—	—	—	—
Infill Drilling	—	—	—	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	(1)	—	(1)
Economic Factors	(16)	(3)	(19)	(2)	—	(2)	37	9	46
Technical Revisions (2)	(52)	(19)	(71)	(66)	(48)	(114)	244	(711)	(467)
Production	(27)	—	(27)	(36)	—	(36)	(1,295)	—	(1,295)
Dec 31, 2023 (3)	221	58	279	596	244	840	21,123	9,020	30,143

Notes:

(1) Opening balances based on an evaluation report prepared by Sproule dated February 7, 2023 with an effective date of December 31, 2022.

(2) Technical Revisions also include changes in reserves associated with changes in operating costs, capital costs and commodity price offsets.

(3) Columns may not add due to rounding.

Year-over-year changes in the Company's estimated gross reserves from December 31, 2022 to December 31, 2023 are primarily the result of: (i) mineral rights expiries resulting in the removal of certain previously-booked proved undeveloped reserves and probable undeveloped reserves (technical revisions); (ii) improved well performance and reactivations resulting in positive technical revisions (technical revisions); (iii) changes in Sproule's 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, 2023, 2022 and 2021 and, in the aggregate, before that time, based on forecast prices and costs.

Proved Undeveloped Reserves

	Light and 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
2021	204	6,221	304	304	1,788	14,371	3	232	809	9,152
2022	308	6,407	—	283	2,199	15,956	33	271	708	9,621
2023	—	6,153	—	282	—	14,703	—	233	—	9,119

Probable Undeveloped Reserves

	Light and 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
2021	246	4,271	312	312	1,532	10,978	2	171	816	6,584
2022	(95)	4,107	—	363	(620)	10,183	(3)	172	(200)	6,339
2023	—	3,921	—	349	—	9,006	—	136	—	5,907

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 certain proved reserves 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 2024, pending capital investment.

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

The Company 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 end-of-life costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard required under applicable laws and regulatory requirements. These ongoing environmental obligations are expected to be funded with internally-generated cash flows.

Our method for estimating the amount and timing of future abandonment and reclamation expenditures was created at an operating area level, using the Company'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, 2023, available on Prairie Provident's website at www.ppr.ca and under its issuer profile on SEDAR+ at www.sedarplus.ca.

As at December 31, 2023, the Company had 1,358 gross (1,067 net) wells for which it expected to eventually incur abandonment costs, and 2,485 gross (1,987 net) wells for which it expected to eventually incur reclamation costs.

Following completion of the Dispositions as described above under "*Company Overview and Background – General Development of Our Business – Recent Developments*", the Company now has 956 gross (713 net) wells for which it expects to eventually incur abandonment costs, and 2,008 gross (1,567 net) wells for which it expects to eventually incur reclamation costs.

The economic forecasts involved in the reserves estimates contained in this AIF include estimated end-of-life costs to abandon, decommission and reclaim all our facilities, pipelines and wells to restore properties to the standard required under applicable laws and regulatory requirements ("**ADR costs**"), including undeveloped reserves locations and properties with no attributed reserves.

In its estimate of net present value of future net revenue of the Company's total proved and probable reserves as at December 31, 2023, the Sproule Report deducted $40 million of estimated ADR costs discounted at 10% ($254 million undiscounted and inflated over time), of which approximately 32% was attributed to inactive assets.

In connection with the Dispositions described above under "*Company Overview and Background – General Development of Our Business – Recent Developments*", the purchasers assumed future abandonment, decommissioning and reclamation obligations pertaining to the Sold Properties. Of the $40 million of estimated ADR costs discounted at 10% ($254 million undiscounted and with inflation) deducted in the Sproule Report's estimate of net present value of future net revenue of proved and probable reserves as at December 31, 2023, $6 million discounted at 10% ($77 million undiscounted and inflated over time) was attributed to the 3 Sold Properties.

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.

	Forecast Prices and Costs ($000s) – Undiscounted	
Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2024	88,815	96,799
2025	37,162	47,921
2026	32,953	43,076
2027	5,033	14,913
2028	—	6,489
Thereafter	—	—
Total (undiscounted)	163,963	209,198
Total (discounted at 10%)	149,425	186,174

The Company currently expects that the capital required to fund estimated future development costs will be provided from its internally-generated cash flows, 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, 2023 and were capable of producing but not then producing at such time, approximately 77% of such reserves were attributed to waterflood reserves, approximately 23% were attributed to oil and natural gas wells to be reactivated.

Michichi Area (Southeastern Alberta)

The Michichi area is located east of Calgary in southeastern Alberta. As of December 31, 2023, we have an average working interest of approximately 82% in 204,685 gross (167,869 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, 2023, our average sales volumes in the Michichi area were approximately 1,220 boe per day (42% 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, 2023, we have an average working interest of approximately 99% in our Princess properties comprising 17,684 gross (17,459 net) acres. The primary zones of interest are the Glauconite, Detrital and Ellerslie formations. During the year ended December 31, 2023, our Princess properties produced average sales volumes of approximately 917 boe per day (75% 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.

Evi Area (Peace River Arch – Northern Alberta)

On March 4, 2024, the Company completed the sale of all its Evi-area assets. See "*Company Overview and Background – General Development of Our Business – Recent Developments*" above.

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, 2023, we had an average working interest of approximately 76% in 58,945 gross (44,572 net) acres in and near the Evi field. During year ended December 31, 2023, our Evi properties produced average sales volumes of approximately 827 boe per day (95% light oil and NGLs). See "*Additional Information Relating to Reserves Data – Production History*".

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, 2023. A wellbore 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	360	303	563	458	175	130	221	150
Saskatchewan	—	—	4	4	—	—	2	2
Northwest Territories	—	—	—	—	—	—	1	1
Total	360	303	567	462	175	130	224	153

Note:

(1) Non-producing wells include wells capable of producing, but not producing, at December 31, 2023. Non-producing wells do not include wells that have been abandoned.

The table above includes wells that were subsequently sold in the Dispositions described above under "*Company Overview and Background – General Development of Our Business – Recent Developments*". The Sold Properties included 187 gross (156 net) producing oil wells, 206 gross (190 net) non-producing oil wells, 3 gross (2 net) producing natural gas wells, and 6 gross (7 net) non-producing natural gas wells – all located in Alberta.

Properties With No Attributed Reserves

The following table summarizes undeveloped acreage (unproved properties) in which the Company owned a working interest or held an exploration license as of December 31, 2023. 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 (unproved properties)	
	Gross	**Net**
Alberta	105,531	80,435
Saskatchewan	321	139
British Columbia	1,126	489
Northwest Territories	2,379	1,586
East Coast (offshore)	11,918	338
Total	121,275	82,987

As at December 31, 2023, 3,713 acres of our net undeveloped acreage was due to expire in 2024 if tenure is not extended by exploration or production activities.

Undeveloped acreage is unproved properties that have not been assigned reserves, and are mineral agreement specific. As of December 31, 2023, the Company did not have any other material work commitments related to its undeveloped acreage.

The table above includes undeveloped acreage that was subsequently sold in the Dispositions described above under "*Company Overview and Background – General Development of Our Business – Recent Developments*". The Sold Properties included 3,713 gross (2,492 net) acres of unproved properties – all located in Alberta.

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 "*– Additional Information Relating to 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, 2023 is set forth in Note 21 (Financial Instruments, Fair Values and Risk Management) in the Company's annual financial statements for the year ended December 31, 2023, available on Prairie Provident's website at www.ppr.ca and under its issuer profile on SEDAR+ at www.sedarplus.ca.

Tax Horizon

The Company will not be required to pay cash income taxes for the year ended December 31, 2023. Based on current estimates of future taxable income and deductible expenditures, and available tax pools, the Company does not currently anticipate any material cash income taxes prior to 2071.

Costs Incurred

The following table summarizes the property acquisition, exploration, and development costs incurred by the Company for the year ended December 31, 2023.

Expenditures	**($000s)**
Property acquisition (disposition) costs (net) – proved properties	(669)
Property acquisition (disposition) costs (net) – unproved properties (1)	493
Exploration Costs (2)	—
Development Costs (3)	165
Capitalized G&A and other	38
Total	27

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 Company did not drill any wells during the year ended December 31, 2023, and did not otherwise have an interest in any exploratory wells or development wells completed during the year.

Production Estimates

The following table sets forth the estimated 2024 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 at December 31, 2023, 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 the Evi, Michichi and Princess fields.

	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Total Oil Equivalent (boe/d)
PROVED RESERVES						
Evi [(1)]	1,221	-	207	-	3	1,258
Princess	507	162	1,231	-	-	874
Michichi	1,894	-	10,762	42	128	3,823
Other Properties	217	37	253	-	5	301
Total Proved	3,838	199	12,453	42	136	6,256
PROBABLE RESERVES						
Evi [(1)]	80	-	9	-	-	82
Princess	18	83	170	-	1	131
Michichi	731	-	2,719	1	111	1,295
Other Properties	4	1	6	-	-	6
Total Probable	833	84	2,904	1	112	1,514
PROVED PLUS PROBABLE RESERVES						
Evi [(1)]	1,301	-	216	-	3	1,340
Princess	525	245	1,401	-	1	1,005
Michichi	2,625	-	13,481	43	239	5,118
Other Properties	221	38	259	-	5	307
Total Proved plus Probable	4,672	283	15,357	43	248	7,769

Note:

(1) Subsequent to year-end, on March 4, 2024, the Company sold all of its interests in the Evi field pursuant to the Dispositions described above under "*Company Overview and Background – General Development of Our Business – Recent Developments*".

The Evi and Michichi fields are the only properties that accounted for 20% or more of the Company's estimated 2024 production as reflected in the Sproule Report.

On March 4, 2024, the Company sold all of its interests in the Evi field pursuant to the Dispositions described above under "*Company Overview and Background – General Development of Our Business – Recent Developments*".

Production History

The following table summarizes, on a quarterly basis for the year ended December 31, 2023, 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, 2023	**June 30, 2023**	**Sept 30, 2023**	**Dec 31, 2023**
Average Daily Production [(1)]				
Light and Medium Crude Oil (bbls/d)	1,738	2,140	2,020	1,894

	Quarter Ended			
	March 31, 2023	June 30, 2023	Sept 30, 2023	Dec 31, 2023
Heavy Crude Oil (bbls/d)	532	152	135	155
Conventional Natural Gas (Mcf/d)	8,099	7,465	7,629	7,270
Coal Bed Methane (Mcf/d)	81	53	57	104
NGLs (bbls/d)	100	97	88	135
Combined (boe/d)	3,733	3,642	3,524	3,413
Average Price Received (2)				
Light and Medium Crude Oil ($/bbl)	87.29	84.74	98.84	87.05
Heavy Crude Oil ($/bbl)	75.96	79.42	84.31	87.88
Conventional Natural Gas ($/Mcf)	3.23	2.23	2.60	2.10
Coal Bed Methane ($/Mcf)	4.35	2.61	2.47	2.24
NGLs ($/bbl)	62.44	55.24	54.77	43.08
Combined ($/boe)	59.84	59.19	66.95	58.54
Royalties Paid				
Light and Medium Crude Oil ($/bbl)	13.56	12.55	14.60	14.79
Heavy Crude Oil ($/bbl)	15.23	15.07	17.44	17.86
Conventional Natural Gas ($/Mcf)	0.29	0.12	0.14	0.13
Coal Bed Methane ($/Mcf)	0.69	0.37	0.27	0.16
NGLs ($/bbl)	27.67	21.43	22.59	29.87
Combined ($/boe)	10.22	5.32	9.92	11.00
Production (Operating) Costs (3)(4)				
Light and Medium Crude Oil ($/bbl)	40.21	35.84	31.64	40.93
Heavy Crude Oil ($/bbl)	42.41	14.78	18.61	31.81
Conventional Natural Gas ($/Mcf)	5.25	4.05	4.35	5.13
Coal Bed Methane ($/Mcf)	0.84	2.96	2.50	1.20
NGLs ($/bbl)	32.59	30.97	29.52	29.37
Combined ($/boe)	36.16	30.85	27.88	37.50
Netback Received (5)				
Light and Medium Crude Oil ($/bbl)	33.52	36.35	52.59	31.34
Heavy Crude Oil ($/bbl)	18.33	49.57	48.27	38.21
Conventional Natural Gas ($/Mcf)	(2.30)	(1.94)	(1.89)	(3.16)
Coal Bed Methane ($/Mcf)	2.82	(0.73)	(0.29)	0.88
NGLs ($/bbl)	2.18	2.85	2.66	(16.16)
Combined ($/boe)	13.46	23.02	29.15	10.03

Notes:

(1) Before deduction of royalties.

(2) Not including any realized losses/gains on the Company's forward contracts on crude 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, 2023.

	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	Natural Gas Liquids (bbls/d)	Total Oil Equivalent (boe/d)
Evi	788	-	227	-	1	827
Princess	539	145	1,394	-	-	1,568
Michichi	512	-	5,669	74	99	1,568
Other Properties	205	-	216	-	5	246
Total	2,044	145	7,506	74	106	3,558

INDUSTRY CONDITIONS

The oil and gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. These laws and regulations 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, and the decommissioning of oil and gas well sites and facilities. 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

Producers are highly sensitive to commodity prices, which fluctuate in response to supply, demand and a number of other factors outside of the Company's control.

Crude Oil

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Oil prices are primarily based on worldwide supply and demand, including as a result of the factors described below; however, regional market and transportation issues also influence prices. Specific prices depend in part on oil quality, prices of competing fuels, distance to market, access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms.

Following the COVID-19 pandemic, oil markets began to rebalance in 2021 and continued to rebound into 2022 with a surge in oil prices in early 2022 primarily driven by the impact of the Russian invasion of Ukraine and the Organization of Petroleum Exporting Countries ("**OPEC+**") decision to adhere to previously agreed-upon production cuts. Additionally, the global economic conditions and outlook improved due to reducing and easing COVID-19 restrictions. In June 2023, OPEC+ producers agreed to target lower oil supply up until the end of 2024 in order to stabilize the price of oil. In anticipation of a potential surplus, in November 2023, OPEC+ producers agreed to a voluntary cut in output for the first quarter of 2024. While the trajectory of oil prices continue to be subject to uncertainty and volatility, factors such as transportation disruptions, supply constraints and the geopolitical conflict continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors*" below.

Natural Gas

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

Natural Gas Liquids

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

Oil and Gas Exports from Canada

In 2019, the National Energy Board (the "**NEB**") was replaced by the Canadian Energy Regulator (the "**CER**"). The CER's governing legislation is the *Canadian Energy Regulator Act* ("**CERA**") and the *Impact Assessment Act* (Canada) (the "**IAA**"). The CER assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada.

Exports of crude oil, natural gas and NGLs from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**") until such time as the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas (other than NGL) not exceeding 30,000 m3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). With respect to applications for long-term export licences, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes are not greater than Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

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

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. The transportation capacity deficit is not likely to be resolved quickly. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints, Pipeline Capacity and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced lower commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines will require a federal regulatory review and approval by Cabinet. For major projects, an assessment may be required by the Impact Assessment Agency of Canada to consider environmental, health, economic, social and gender impacts, as well as impacts on Canada's climate change commitments. Even when projects are approved, they often face delays due to actions taken by provincial and municipal governments. The assessment criteria and process is currently under review as a result of a 2023 decision from the Supreme Court of Canada in *Reference re Impact Assessment Act*, which found that parts of the IAA are unconstitutional.

Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals from several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, could help to alleviate the downward pressures affecting commodity prices. Several proposals have been announced to increase pipeline capacity out of Western Canada to reach Eastern Canada, the United States and international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other economic and socio-political factors related to transportation and export infrastructure has led to the delay, suspension or cancellation of many projects. The United States presidential election is set to occur in the fall of 2024, which may result in a shift in the political agenda in the United States in the coming years, including a change in control of the house and/or the senate. Uncertainty remains as to the advancement of pipeline projects between Canada and the United States.

Pipeline Projects

Enbridge Line 3

After more than eight years, which included permitting difficulties in the United States and associated delays, 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.

Trans Mountain Pipeline

In May 2018, the Canadian federal government agreed to purchase the Trans Mountain Pipeline system. In August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment of the proposed Trans Mountain Pipeline expansion and the federal government's Indigenous consultations. The Court quashed the Cabinet's approval of the project and the certificate of public convenience and necessity therefor issued by the NEB, and directed that the government correct these deficiencies. Following a reconsideration by the NEB and enhanced consultation efforts led by the federal government, Cabinet reapproved the Trans Mountain Pipeline expansion. Subsequent challenges to the approval were rejected by the Federal Court of Appeal in February 2020 and by the Supreme Court of Canada in July 2020. By June 2020, approximately 86% of the route had been approved. In 2021, further regulatory proceedings occurred with Trans Mountain seeking certain route variances. It is currently anticipated that the pipeline will be fully operational by summer 2024.

Keystone XL Pipeline

In March 2020, following receipt of a U.S. federal government permit, TC Energy Corporation announced that it would proceed with the Keystone XL Pipeline project. The project would have had the capacity to carry 830,000 bbl/d of crude oil. In 2021, however, the new U.S. administration announced its decision to revoke the presidential permit for the Keystone XL border crossing that had been granted by the previous administration. In June 2021, TC Energy announced that it was terminating the Keystone XL project.

Enbridge Line 5 Tunnel Replacement

In December 2023, Michigan Public Service Commission approved Enbridge's Line 5 Tunnel Replacement Project ("**Line 5**"), marking the end of a more than three-year long evaluation process. Line 5 is seen as crucial infrastructure supplying Michigan, Ontario and Québec. This approval begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straights of Mackinac. The U.S. Army Corps of Engineers has initiated an environmental impact assessment, which is expected to be completed by 2026.

Natural Gas and Liquefied Natural Gas (LNG)

Natural gas prices in Alberta have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further capacity constraints and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. ("**NGTL**") pipeline system (the "**NGTL System**") to prioritize deliveries into storage. The change stabilized supply and pricing, particularly during periods of maintenance on the system. NGTL is progressing construction activities on its system expansion project intended to increase capacity by 3.5 Bcf/d. Different aspects of that project came online throughout 2021 and all components are expected to be completed by 2026.

While a number of liquefied natural gas (LNG) export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. In October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project.

Once complete, the project will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities began in November 2018, with a planned completion target of 2025. Despite its approval, the CGL Pipeline has faced intense legal and social opposition. In November 2023, TC Energy announced that the CGL Pipeline had reached mechanical completion. At December 31, 2023, LNG Canada was reported to be 85% complete and preparing for safe start-up procedures to start in 2024, for first deliveries by LNG Canada to occur by the middle of the decade.

In addition to LNG Canada and the CGL Pipeline projects, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

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 ("**CUSMA**"), which came into force on July 1, 2020 and replaced 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 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, 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.

It is uncertain what ultimate effect other trade agreements will have on the oil and gas industry in Canada, as the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

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 and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the Western Canadian provinces have established incentive programs for exploration and development. Such programs may provide for royalty reductions, credits or holidays, and are generally introduced when commodity prices are low to encourage exploration and development activity. Additional programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs or improve environmental performance.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the petroleum and natural gas industry. Recently, these programs, have included but are not limited to: programs that provide direct financial support to companies operating in the petroleum and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic, administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada and funding administered by certain provinces to address the cleanup of inactive wells, pipelines and facilities such as Alberta's Site Rehabilitation Program.

Incentive programs are often of limited duration and target specified activities, and may be amended or removed at any time.

Alberta – Royalties

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

With respect to production from Crown lands, royalties are payable to the Province of Alberta. With respect to production freehold lands, royalties are payable to the mineral owner and taxes are payable to the Province of Alberta. The Government of Alberta's approach to the royalty and tax regime is regularly reviewed for compliance with the purpose of the regimes; to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees.

The Modernized Royalty Framework for Alberta ("**MRF**") formally took effect on January 1, 2017 for new wells drilled after this date. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the MRF. The *Royalty Guarantee Act* (Alberta), which came into effect on July 18, 2019, provides that no major changes will be made to the current crude oil and natural gas royalty structure for a period of at least 10 years.

The MRF applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the MRF is determined on a "revenue-minus-costs" basis with the cost component based on a drilling and completion cost allowance formula for each well, depending on its vertical depth and horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator ("**AER**") on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the MRF until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all 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 MRF 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, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines.

As the MRF uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the drilling and completion cost allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, 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 deep, as well as the acid gas content of the produced gas. Subject to certain available incentives, 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.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells. In addition to royalties, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments, at a rate of $3.50 per hectare.

The AER has established the Orphan Fund, funded by oil and gas companies, to cover the cost of cleaning up orphaned wells and facilities where the owner cannot be located or has gone out of business. The program requires each oil and gas licensee to pay an annual levy calculated based on their estimated cost of decommissioning their inventory.

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.

Environmental Regulation

The Canadian oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling, disposal and storage, habitat protection and the satisfactory operation, maintenance, abandonment, remediation and reclamation of well, facility and pipeline sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Prairie Provident has established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which the Company operates. The Company ensures that its operations are carried out in accordance with applicable environmental requirements, guidelines and safety precautions. Although the Company maintains pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Federal

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

The Canadian Environmental Protection Act, 1999 and the Canadian Environmental Assessment Act, 2012 provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

In August 2019, with the passing of Bill C-69, the CERA and the Impact Assessment Act ("**IAA**") came into force and the NEB Act and the Canadian Environmental Assessment Act, 2012 were repealed. The IAA established the Impact Assessment Agency of Canada ("**IA Agency**"), which replaced the Canadian Environmental Assessment Agency and is tasked with leading and coordinating impact assessments for all designated projects, including those previously administered by the NEB. The new 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 replaced the NEB with the CER, and modified the CER's role in federal impact assessments.

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Designated projects will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The IA Agency must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75 kilometers of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial GHG emissions and certain refining, processing and storage facilities will also require an impact assessment.

There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Government of Alberta, supported by the governments of Ontario and Saskatchewan, challenged the constitutionality of the IAA and requested that the federal legislation be invalidated on the basis that it encroaches on provincial jurisdiction. An Alberta Court of Appeal decision found Bill C-69 to be invalid and the decision was appealed to the Supreme Court of Canada. In October 2023, the Supreme Court of Canada released its decision which held portions of the IAA to be unconstitutional. Amendments to the IAA are anticipated to be brought forward in the spring of 2024.

On June 21, 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act received Royal Assent and immediately came into force. Bill C-15 is the Government of Canada's response to requests to implement the United Nations Declaration of the Rights of Indigenous Peoples as a framework for reconciliation in Canada. This follows increased requirements for indigenous consultation.

Provincial

The discharge of pollutants into the air, soil or water may give rise to liabilities, impact the Company's ability to operate and may require the Company to incur costs to remedy such discharge in the event that they are not covered by the Company's insurance. Although the Company maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and GHG emissions, may impose further requirements on operators in the oil and gas industry.

Liability Management Programs

The Province of Alberta has developed a liability management program as one of the main tools for managing the environmental liabilities of the oil and gas industry. Historically, the program focused on a licensee liability rating ("**LLR**") and orphan funds. The LLR assigned ratios based on deemed assets and liabilities, which would provide guidance as to when security would be required to be posted and whether a license transfer would be required.

Alberta has also established an Orphan Well Fund, primarily funded by industry through annual levies administered by the AER and managed by the industry-funded Orphan Well Association ("**OWA**"), which is intended to help pay the costs of certain types of wells, facilities and pipelines where the licensee or working interest participant ("**WIP**") becomes insolvent or otherwise unable to meet its obligations.

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.

As a result of the Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "Redwater" decision), Alberta has amended its liability management programs. The Redwater decision found that receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability while dealing with the company's valuable assets for the benefit of the company's creditors without first satisfying abandonment and reclamation obligations.

In December 2019, the AER ceased posting the detailed LMR report and has since then replaced its LMR program with a holistic assessment of licensees capabilities and performance across the energy development life cycle. In April 2020, the Government of Alberta passed Bill 12: The Liabilities Management Statutes Amendment Act. Bill 12 places the burden of a defunct licensees' abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. Bill 12 came into force on proclamation in June of 2020.

In response to the increase in orphaned crude oil and natural gas sites and the environmental risks associated therewith, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. The AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licence eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings as well as to require the provision of financial information annually. As a result of the changes to Directive 067, the AER may revoke or restrict a company's eligibility to hold AER licences if the AER determines that the licensee poses an "unreasonable risk", taking into account a broad range of financial and operational considerations. On December 1, 2021, the AER published a new Directive 088: Licensee Life-Cycle Management and supporting guidance information including Manual 023. Among other things, Directive 088 establishes the AER's authority to conduct a holistic licensee assessment to inform regulatory decisions about a given licensee, including by conducting a "Licensee Capability Assessment." Directive 088 also establishes the "Licensee Management Program" which enables the AER to proactively monitor licensees to identify those at risk of not meeting their regulatory obligations and to use appropriate regulatory tools to address that risk. Finally, Directive 088 establishes the Inventory Reduction Program and allows the AER to set licensee-specific and industry-wide closure targets. In January 2022, the AER set out the first annual spend requirements under the Inventory Reduction Program which requires licensees on an annual basis to spend minimum amounts on abandonment, remediation and reclamation of inactive wells, pipelines or facilities. Failure to comply may result in the requirement to post security and impact the Company's licensee capability assessment.

Additionally, licensees in Alberta are now required to spend minimum prescribed amounts on addressing liabilities associated with inactive assets. The AER sets a mandatory spend quota each year based on each licenses proportion of the industry-wine inactive liability rate. The rate for 2023 was 6.7% and the rate for 2024 is 6.6% of a licensee's deemed inactive liability. A lower spend rate is applied for licensees with a high level of financial distress.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulation of the crude oil and natural gas industry in Canada. In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. In April 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the convention have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

In March 2022, the Government of Canada introduced Canada's 2030 Reduction Plan for achieving its commitment. In November 2022, at COP27 the Government of Canada signed on to a joint declaration on reducing greenhouse gas emissions from fossil fuels and to support efforts to accelerate global transitions to clean energy.

On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "GGPPA"), which came into force on January 1, 2019. On March 25, 2021, following challenges to the constitutionality by multiple provinces, the SCC released its decision in Reference re Greenhouse Gas Pollution Pricing Act, upholding the constitutionality of a federal law establishing minimum national standards for carbon pricing in Canada. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of CO2e emissions, increasing to $170/tonne by 2030. 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. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform minimum price on emissions across the country. The price is set to increase from $65/tonne to $80/tonne on April 1, 2024.

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, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, reinject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The Federal Government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

As part of its efforts to provide relief to Canada's petroleum and natural gas industry in light of the COVID-19 pandemic, on October 29, 2020, the federal government launched the $750-million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies.

The federal government has enacted the Multi-Sector Air Pollutants Regulation under the authority of the Canadian Environmental Protection Act, 1999, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream petroleum and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

On July 1, 2023, the federal government's Clean Fuel Regulations ("**CFR**") came into effect and require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. The CFR take a performance-based approach to reducing greenhouse gas emissions and require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of the applicable fuel over time. It is the goal of the program to incentivize innovation and adoption of clean technologies while giving fuel suppliers the ability to meet requirements in a cost-effective way that works for their business. The proposed regulations offer compliance credits to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "CLP"). On December 14, 2016, the Oil Sands Emissions Limit Act came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions. Under the CLP, the Climate Leadership Act (the "CLA") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this increased most recently to $65/tonne on April 1, 2023 and is set to increase to $80/tonne on April 1, 2024. On December 4, 2019, the federal government approved Alberta's proposed Technology Innovation and Emissions Reduction ("**TIER**") regulation such that the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still otherwise applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation applies to industry-wide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year, or a facility that imports more than 10,000 tones of hydrogen in 2023 or a subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. The TIER regulation targets emissions intensity rather than total emissions.

Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 2,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated together under the TIER regulation as an "aggregated facility". To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta. The TIER regulation will continue to apply in Alberta for as long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, 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. The release of 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 new Directives represented Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations. Alberta reached the methane emissions reductions target of 45% by 2025 in 2022, three years early.

CAPITAL STRUCTURE AND OUTSTANDING SECURITIES

Share Capital

The authorized share capital of Prairie Provident consists of an unlimited number of Common Shares, of which 716,105,903 Common Shares are outstanding as of the date of this AIF (715,598,393 as of December 31, 2023) 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 to 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.

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) the share purchase warrants forming part of the Units issued and sold in the Equity Financing, and the Broker Warrants issued in connection therewith, as more particularly described above under "*Company Overview and Background – General Development of our Business – Recapitalization*"; and (ii) incentive awards granted and outstanding under Prairie Provident's security-based compensation arrangements and held by directors, officers and employees.

Outstanding incentive awards at the date of this AIF are comprised of: (i) 3,895,546 incentive stock options held by officers and employees, each exercisable for one Common Share at a specified exercise price, subject to vesting in accordance with their terms; (ii) 3,007,567 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) 2,031,667 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.

Escrow

To the knowledge of the directors and executive officers of the Company, other than restrictions applicable to the transfer of incentive awards and the 'lock-up' restrictions agreed with the Former Noteholder in connection with the

Subordinated Notes Settlement, as more particularly described above under "*Company Overview and Background – General Development of our Business – Recapitalization*", 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 2023	0.160	0.110	2,358,539
February 2023	0.150	0.120	1,858,738
March 2023	0.150	0.070	6,037,063
April 2023	0.095	0.080	3,353,605
May 2023	0.095	0.075	5,299,788
June 2023	0.050	0.070	2,277,459
July 2023	0.120	0.070	5,784,480
August 2023	0.145	0.100	5,616,045
September 2023	0.130	0.095	6,409,837
October 2023	0.115	0.090	5,328,047
November 2023	0.100	0.070	3,498,463
December 2023	0.070	0.060	2,238,529
January 2024	0.070	0.055	1,403,886
February 2024	0.075	0.050	2,424,347
March 2024	0.095	0.060	1,813,279

Prior Sales

In connection with completion of the Recapitalization in 2023 – including the Equity Financing, Subordinated Notes Settlement and Warrant Exercise – Prairie Provident issued:

- US$3.64 million principal amount of second lien notes due December 31, 2024;
- pursuant to the Equity Financing, 44,444,444 Units at a price of C$0.09 per Unit for aggregate gross proceeds of C$4 million, each Unit being comprised of one Common Share and one warrant exercisable for an additional Common Share at an exercise price of C$0.10 per share for a 5-year term ending May 16, 2028;
- pursuant to the Subordinated Notes Settlement, 514,408,902 Common Shares at an agreed repayment price equal to C$0.14 per Common Share;
- pursuant to the Warrant Exercise, an additional 26,516,207 Common Shares; and
- pursuant to the Equity Financing, 3,555,555 Broker Warrants, each entitling the holder to subscribe for and purchase one Unit at an exercise price of C$0.09 per Unit for a 5-year term ending May 16, 2028;

all as more particularly described above under "*Company Overview and Background – General Development of our Business – Recapitalization*".

During 2023, Prairie Provident also granted an aggregate of 2,500,000 DSUs, 2,040,000 RSUs and 2,760,000 stock options under its security-based compensation arrangements, and issued a total of 515,952 Common Shares on the settlement of vested RSUs and exercise of vested stock options.

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 officer since
Patrick McDonald (1)(3) 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; Interim Chief Executive Officer of the Company from December 2022 to December 2023.	March 2011
Glenn Hamilton (1)(2)(5) Alberta, Canada *Director*	Corporate Director; Director of Ember Resources Inc., Inter Pipeline Ltd. and Islander Oil & Gas Inc.; Corporate Advisor to Bonavista Energy Corporation (oil and gas exploration and development) from May 2015 until July 2016, and prior thereto its Senior Vice President and Chief Financial Officer from June 2008 until May 2015.	July 2023
Dale Miller (1)(3)(4)(6) Alberta, Canada *Director*	Corporate Director, Director of Yangarra Resources Ltd since April, 2021, President of Dark Horse Energy Consultants Ltd since 2017, COO of Hillcrest Petroleum Ltd June, 2018 to April, 2021, and prior thereto President/COO/Director of Long Run Exploration Ltd August, 2011 to April, 2017.	August 2023
Matthew Shyba (2)(3)(4)(5)(6) Alberta, Canada *Director*	Chief Executive Officer of Shyba Capital Inc. (private investment company) since January 2022; Private corporate law practice since August 2019; prior thereto, Associate General Counsel of AutoCanada Inc. (automobile dealer) from February 2015 until July 2019.	July 2022
Kathy Turgeon (2)(4)(5)(6) Alberta, Canada *Director*	Vice President, Finance and Chief Financial Officer of Peyto Exploration & Development Corp. (oil and gas exploration and production) from November 2007 to March 2024.	July 2023

Name, Jurisdiction of Residence and Position with Prairie Provident	Principal Occupations for Past Five Years	Director and/or officer since
Ryan Rawlyk Alberta, Canada *President and Chief Executive Officer, and a Director*	President and Chief Executive Officer of the since January 1, 2024; prior thereto, Chief Operating Officer of the Company from May 2023 to December 2023, and Vice President, Production and Operations of the Company from September 2021 to May 2023; 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.	September 2021
David Stobbe Alberta, Canada *Controller and Chief Financial Officer*	Chief Financial Officer since November 2023; prior thereto, Controller since June 2023; prior thereto, Vice President, Accounting and, before that, Financial Controller and Treasurer at Velvet Energy Ltd. (oil and gas exploration and production) from January 2011 to August 2021.	June 2023

Notes:

(1) Member of the Executive Committee of the Board of Directors, consisting of Dale Miller (Chair), Glenn Hamilton and Patrick McDonald.

(2) Member of the Audit Committee of the Board of Directors, consisting of Glenn Hamilton (Chair), Matthew Shyba and Kathy Turgeon. See "*Audit Committee Information*" below.

(3) Member of the Reserves Committee of the Board of Directors, consisting of Dale Miller (Chair), Patrick McDonald and Matthew Shyba.

(4) Member of the Compensation Committee of the Board of Directors, consisting of Kathy Turgeon (Chair), Dale Miller and Matthew Shyba.

(5) Member of the Nominating and Corporate Governance Committee of the Board of Directors, consisting of Glenn Hamilton (Chair), Matthew Shyba and Kathy Turgeon.

(6) Member of the Environmental, Social and Governance Committee of the Board of Directors, consisting of Kathy Turgeon (Chair), Dale Miller and Matthew Shyba.

The term of office of all current directors expires at the close of the next annual meeting of Prairie Provident's shareholders.

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 14,462,403 Common Shares, representing approximately 2% of the outstanding Common Shares (calculated on an undiluted basis).

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 company (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, which concluded upon its plan of reorganization thereunder becoming effective in August 2016.

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.

AUDIT COMMITTEE INFORMATION

The principal purpose of the Company's audit committee (the "**Audit Committee**") is to assist the Board of Directors in fulfilling its oversight responsibilities regarding the integrity of the Company's financial statements and related accounting, financial reporting and audit processes, internal accounting and financial control systems and procedures, disclosure controls and procedures, the qualification and performance of the Company's independent auditors, and the Company's risk management strategies; and compliance by the Company with applicable legal requirements relating thereto.

Attached as Schedule C to this AIF is a copy of the Audit Committee's current charter.

Audit Committee Composition

The Audit Committee is comprised of Glenn Hamilton (Chair), Matthew Shyba, and Kathy Turgeon. All members are independent of the Company and financially literate within the meaning of Canadian securities legislation.

Following is a brief description of the education and experience of each current Audit Committee member that is relevant to the performance of his responsibilities as a member of the Audit Committee:

- Glenn Hamilton (Chair) – Mr. Hamilton has over 35 years of experience in accounting and finance in the oil and gas industry. He served as Senior Vice President and Chief Financial Officer of Bonavista Energy Corporation from June 2008 until May 2015 and thereafter as Corporate Advisor to Bonavista until July 2016. Mr. Hamilton previously served as Vice President and Chief Financial Officer of NuVista Energy Ltd. from July 2003 until May 2006. He currently sits on the board of directors of each of Ember Resources Inc., Inter Pipeline Ltd., and Islander Oil & Gas Inc. Mr. Hamilton has a Bachelor of Commerce degree from Carleton University and is a Chartered Professional Accountant (CPA-CA) and member of the Chartered Professional Accountants of Alberta. He also holds the ICD.D designation from the Institute of Corporate Directors.

- Matthew Shyba – Mr. Shyba is an experienced corporate lawyer and private investor with over a decade of capital markets experience, including significant expertise in corporate finance, corporate governance and mergers and acquisitions. He is currently Chief Executive Officer of Shyba Capital Inc., a private investment company based in Calgary, and also maintains a private corporate law practice. Mr. Shyba previously practiced in the securities group at Borden Ladner Gervais LLP and subsequently served as Associate General Counsel at AutoCanada Inc. He holds a Juris Doctor law degree from Dalhousie University.

- Kathy Turgeon – Ms. Turgeon has over 25 years of experience in accounting and finance in the oil and gas industry, serving as Chief Financial Officer of Peyto Exploration & Development Corp. from November 2007 until her retirement, effective March 31, 2024. She joined Peyto as Controller in 2004 and was subsequently appointed Vice President, Finance in 2006. Prior to joining Peyto, Ms. Turgeon served as Associate Director, Finance with the Department of Campus Infrastructure and as Internal Auditor for the University of Calgary. Ms. Turgeon previously served as a director of Peyto, and of Granite Oil Corp. Ms. Turgeon has a Bachelor of Commerce degree from the University of Calgary and is a Chartered Professional Accountant (CPA-CA) and member of the Chartered Professional Accountants of Alberta.

- Patrick McDonald, Chairman of the Board of Directors, served as Interim Chief Executive Officer from December 2022 until December 2023 and, as such, was deemed under applicable Canadian securities legislation to no longer be independent for such period. During a portion of 2023, Mr. McDonald temporarily served as a member of the Audit Committee, and in that regard, Prairie Provident relied on the temporary exemption contained in section 3.4 of National Instrument 52-110 – Audit Committees from the requirement thereunder that all audit committee members be independent, which exempts a member in circumstances beyond their reasonable control until the later of 6 months from the event that caused the member to cease to be independent and the next annual meeting of shareholders.

Pre-Approval Policies and Procedures

The Audit Committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

External Auditor Service Fees

The Company's auditor is Ernst & Young LLP, Chartered Professional Accountants, which has served as the auditor of the Company and its predecessor, Lone Pine Resources Inc., since November 2011.

The 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)	**2022**	**2023**
Audit Fees (1)	$291	$362
Audit-Related Fees (2)	—	—
Tax Fees (3)	—	—
All Other Fees (4)	$1	—
Total Fees	$292	$362

Notes:

(1) Audit Fees were for the audit of the annual financial statements and reviews of the quarterly financial statements.

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

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

(4) All Other Fees were 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 materialize 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 involve 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. Moreover, management of the Company may determine that current markets, regulatory requirements, terms of acquisition, participating or pricing conditions make potential acquisitions or participation uneconomic.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including geological and seismic risks, encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on future results of operations, liquidity and financial condition.

As is standard industry practice, the Company is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Insurance*". In either event, the Company could incur significant costs.

Access to Capital

The Company will have to incur operating and capital expenditures in the future in order to carry out its oil and natural gas exploration and development activities. The Company has limited access to capital, and as such, must rely on internally-generated cash flows to operate its business and develop its assets.

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, inflation, isolationist trade policies and growing anti-fossil fuel sentiment, world economic conditions, government regulation, international trade disputes, political stability throughout the world, geopolitical tensions and events, 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, 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 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. Climate concerns and growing anti-fossil fuel sentiment have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. 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.

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

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;

- the note purchase agreements governing the First Lien Facility and the Second Lien Notes require that the Company maintain compliance with certain financial ratios, which include ratios based on an EBITDAX measure that is adversely affected by low commodity prices; and

- the operating and financial restrictions and covenants under the note purchase agreements governing the First Lien Facility and the Second Lien 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.

Uncertainty of Reserves 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. Although Sproule has prepared the Company's reserves figures using methods of estimating reserves with those commonly followed in the industry and believe that those methods have been verified by operating experience, such figures and estimates and no assurance can be given that the indicates levels of reserves will be produced.

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 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 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 and Dispositions

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.

Assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market, assets of the Company may realize less on disposition than their carrying value on the financial statements of the Company.

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 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.

Alternatives to, and Changing Demand for, Petroleum Products

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

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.

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 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 the First Lien Facility and the Second Lien 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 the First Lien Facility and the Second Lien Notes also require that the Company maintain compliance with certain financial ratios.

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 the First Lien 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 the First Lien Facility and the Second Lien 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:

- 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.

Significant Shareholder

To the Company's knowledge, PCEP Canadian Holdco, LLC ("**PCEP**"), a Delaware limited liability company that is indirectly managed by PGIM Private Capital, a unit of PGIM, Inc., directly or indirectly owns or exercises control or direction over 540,925,109 Common Shares representing approximately 75.6% of the total number of Common Shares (undiluted) outstanding at the date of this AIF. As such, PCEP holds a sufficient number of our voting securities to materially affect control of the Company. In particular, the support of PCEP will be required for any matter requiring approval of the Prairie Provident shareholders by special resolution, such as amendments to the Company's articles, a sale of all or substantially all of the assets of the Company, and certain business combination transactions. No party will make any acquisition proposal unless supported by PCEP. Although the interests of all shareholders are generally aligned, PCEP is entitled to act solely in its own interests in the exercise of its rights as a shareholder, whether those interests are consistent or conflict with (and any such conflict may be resolved against) the interests of the Company or any of its shareholders or other stakeholders. Any conflict between PCEP's interests and the interests of the

Company or any of its shareholders or other stakeholders may be resolved contrary to the interests of the Company or its shareholders or other stakeholders.

PCEP acquired its Common Shares pursuant to completion of the Recapitalization described above under "*Company Overview and Background – General Development of our Business – RecapitalizationADR*".

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, macroeconomic developments nationally, within North America or globally, current perceptions of the oil and gas markets, negative investor sentiment towards energy-related businesses or formal decarbonization policies, 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.

Similarly, the market price of the Common Shares may be due to Prairie Provident's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Prairie Provident or its competitors, along with a variety of additional factors. In addition, in recent years the market price for securities in the stock markets, including the TSX, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

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.

Operating and Capital Costs

The Company's financial performance is significantly affected by the cost of operating and the capital costs associated with its assets. Operating and capital costs are affected by a number of factors including, but not limited to inflationary price pressure, scheduling delays, failure to maintain quality standards and supply chain disruptions. The Company's inability to manage costs or to secure equipment, materials or skilled labour necessary to its exploration, development, construction and operations for the expected price, on the expected timeline, or at all, could have a material adverse effect on the Company's financial condition, results of operations and cash flows. Electricity, chemicals, supplies, abandonment, reclamation and labour costs are examples of operating costs that are susceptible to significant fluctuations. Fluctuations in operating and capital costs could negatively impact Prairie Provident's business, financial condition, results of operations, cash flows and value of its oil and gas reserves.

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.

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.

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to access the Company's systems and obtain confidential information. The Company restricts the social media access of its employees and periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Company may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

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 ongoing Russian hostilities in 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.

Other government and political factors that could adversely affect the Company's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Company's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand.

Exposure to Widespread Pandemic

Pandemics, epidemics or other outbreaks, such as the COVID-19 pandemic, may adversely affect local and global economies, as well as Prairie Provident's business and operations as a result of, among other things, the imposition of restrictions and the closure of borders, institutions and businesses deemed non-essential. In addition to the impact on commodity prices and commodity sales, the effects of the pandemics, epidemics or other outbreaks and related government action, have created uncertainty in the financial and energy markets and in the crude oil and natural gas industry.

There can be no certainty regarding the long-term efficacy of and other actions taken to control the spread of COVID-19 or other widespread diseases. Governments will continue to closely monitor the spread of COVID-19 and other viruses and may reintroduce restrictive measures to counter any successive wave or resurgence of COVID-19, its variants or other diseases. Accordingly, the Company's financial or operating performance could be materially adversely impacted by way of suspensions, delays or cancellations of the Company's projects, either by its customers or due to broader government directives, slowdowns or stoppages in the performance of projects due to labor shortages, supply chain disruptions and shortages, increased collection risk from customers, volatility in capital markets, inflation and decreases in customer demand as a result of the impacts of government imposed restrictions, including reduced prices of and global demand for petroleum products caused by travel restrictions and other shut-downs.

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, and in turn, the market price of the Common Shares.

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. 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.

Abandonment and Reclamation Costs

The Company is required to abandon and reclaim all of its projects at the end of their economic life. These costs will be substantial. The estimate for abandonment and reclamation costs are based on several sources including guidelines from provincial regulators, historical data from operations, and management's estimation of costs to remediate, reclaim and abandon wells and facilities in which it has a working interest. Changing legislative requirements may result in increased costs or accelerate the time in which clean up may occur. There can be no assurance that the Company will be able to satisfy its future abandonment and reclamation obligations.

Recently, as a result of the prolonged downturn in the oil and gas industry the number of orphan wells (wells owned by insolvent parties) has increased. The cost of abandoning orphan wells has largely been funded by industry. Accordingly, the increase in the number of orphan wells could result in an increase in fees or assessments to other oil and gas producers, such as Prairie Provident, to fund the abandonment and reclamation of these orphan wells.

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.

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: *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.

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 direct or indirect costs of compliance with these GHG emissions-related legislation 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.

A draft of 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, distributors or importers of gasoline, diesel, kerosene and light and heavy fuel oils. The Clean Fuel Regulations 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. On June 20, 2022, the final Clean Fuel Regulations were published and came into force.

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.

Regulatory 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 has increased significantly and, accordingly, the aggregate value of the abandonment and reclamation liabilities assumed by the OWA in Alberta has increased and may continue to increase. While the Redwater decision of the Supreme Court of Canada may reduce the abandonment and reclamation liabilities ultimately assumed by the OWA 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 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 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. A trial on the calculation of net revenue from primary production at Eyehill Creek was held in June 2022 before the Court of King's Bench of Alberta. In a decision released in December 2022, which was largely in favour of the defendants' proposed calculation methodology, the Court provided a series of directions for calculating the net revenue amount. IFP filed an appeal on January 3, 2023, and the defendant's filed a cross-appeal on January 13, 2023. Although the final outcome of this case remains uncertain in light of the pending appeals, on the available facts the Company does not expect the ultimate disposition of the matter to have a material effect on its business.

The Company is and was not during 2023 otherwise a party to, and its property is and was not during 2023 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, 2023)*, 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 accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to Prairie Provident is filed under its issuer profile on SEDAR+ at www.sedarplus.ca, including financial information provided in its comparative annual financial statements and management's discussion and analysis for the year ended December 31, 2023. 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

Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator

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, 2023. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2023, 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, 2023, 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, 2023	Canada				
Total			Nil	490,200	Nil	490,200

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, 2023)".

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

(signed and sealed) "Matthew Thomas"

ID 84860
Feb. 12, 2024
Matthew Thomas, P.Eng.
Senior Petroleum Engineer

Sproule Associates Limited
APEGA Permit Number 00417

(signed) "Gary R. Finnis"

Gary R. Finnis, P.Eng.
Senior Manager, Engineering
Date: Feb. 12, 2024
RM APEGA ID #: 62965

SCHEDULE B

Form 51-101F3

<u>Report of Management and Directors on Oil and Gas Disclosure</u>

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, 2023, 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: April 2, 2024

(signed) "Ryan Rawlyk"	*(signed) "David Stobbe"*
Ryan Rawlyk	David Stobbe
Chief Executive Officer	Chief Financial Officer
(signed) "Dale Miller"	*(signed) "Patrick McDonald"*
Dale Miller	Patrick McDonald
Director	Director

SCHEDULE C

AUDIT COMMITTEE CHARTER

* * * * *

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

- <u>Meetings</u>. 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.

- <u>Quorum</u>. 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.