# BONTERRA ENERGY CORP.

ANNUAL INFORMATION FORM

For the year ended December 31, 2024

March 13, 2025

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*The information in this AIF is given as of December 31, 2024 unless otherwise indicated.*

# GLOSSARY OF TERMS

Unless the context otherwise requires, in this Annual Information Form, the following terms and abbreviations have the meanings set forth below.

**"Bonterra"** means Bonterra Energy Corp. the Company formed on amalgamation of Bonterra Corp. and Bonterra Oil & Gas Ltd. effective January 1, 2010;

**"Bonterra Corp."** means Bonterra Energy Corp. a former wholly owned subsidiary of Bonterra Trust which was wound-up and dissolved January 1, 2010;

"**Bonterra Oil & Gas Ltd.**" means the former corporation whose assets consisted of all the issued and outstanding trust units of Bonterra Trust;

**"Bonterra Trust"** means Bonterra Energy Income Trust;

**"Economic Life"** means, with respect to an oil and gas property, the time remaining before production of petroleum substances from the property is forecast to be uneconomic;

**"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;

**"Reserve Life Index"** or **"RLI"** is an index reflecting the theoretical production life of a property if the remaining reserves were to be produced out at current production rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the annualized fourth quarter production from the preceding twelve month period;

**"Shareholder"** means a holder of Bonterra common shares;

**"Sproule"** means Sproule Associates Limited, independent petroleum consultants;

**"Sproule Report"** means the independent engineering evaluation of Bonterra's oil, natural gas and NGLs interests prepared by Sproule dated February 7, 2025 and effective December 31, 2024 utilizing the average commodity price forecasts of Sproule, GLJ Petroleum Consultants and McDaniels & Associates Consultants Ltd. dated December 31, 2024; and

**"Trustee"** means Odyssey Trust Company, or its successor as trustee of the Company.

# ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl – barrels
MBbl – thousand barrels
Bbl/d – barrels per day
NGLs – natural gas liquids

Natural Gas

GJ – gigajoules
GJ/d – gigajoules per day
Mcf – thousand cubic feet
MMcf – million cubic feet
MMbtu – million British thermal units
Bcf – billion cubic feet
Mcf/d – thousand cubic feet per day

Other

AECO means Alberta Energy Company interconnect with the NOVA System.
BOE means barrel of oil equivalent. In all cases of this document, a BOE conversion ratio for natural gas of 6 Mcf:1Bbl has been used. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading, particularly if used in isolation.
MBOE means thousand BOE.
BOE/d means BOE per day.
WTI means West Texas Intermediate at Cushing, Oklahoma, the benchmark crude oil for pricing purposes.
GCA means gas cost allowance deduction taken off of provincial (Crown) royalties, to offset the capital and direct operating costs associated with processing the Crown's share of raw gas at a gas plant and transporting the Crown's share of residue gas through a sales line.

# CONVERSIONS

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

| To convert from | To | Multiply By |
|---|---|---|
| Mcf | Cubic Metres | 28.174 |
| Cubic Metres | Cubic Feet | 35.494 |
| Bbl | Cubic Metres | 0.159 |
| Cubic Metres | Bbl | 6.293 |
| Feet | Metres | 0.305 |
| Metres | Feet | 3.281 |
| Miles | Kilometres | 1.609 |
| Kilometres | Miles | 0.621 |
| Acres | Hectares | 0.405 |
| Hectares | Acres | 2.471 |

# ADVISORY

In this Annual Information Form where amounts are expressed on a barrel of oil equivalent basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil, based on the current market prices thereof, is significantly different from the energy equivalency ratio of six to one, utilizing a BOE conversion ratio on this basis may be misleading as an indication of value.

Unless otherwise specified, references to oil include oil and NGLs. NGLs include condensate, propane, butane and ethane.

Where any disclosure of reserves data is made in this Annual Information Form or the documents incorporated by reference herein that does not reflect all of the reserves of Bonterra, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of the reserves and future net revenue for all properties, due to the effects of aggregation.

## PRESENTATION OF OIL AND GAS INFORMATION

All oil and gas information contained in this Annual Information Form or the documents incorporated by reference herein, has been prepared and presented in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101). The actual oil and gas reserves and future production will be greater than or less than the estimates provided herein. The estimated value of future net revenue from the production of the disclosed oil and gas reserves does not represent the fair market value of these reserves. There is no assurance that the forecast prices and costs or other assumptions made in connection with the reserves disclosed herein will be attained and variances could be material.

## DEFINITIONS AND NOTES TO RESERVE DATA TABLES

Certain terms used herein are defined in NI 51-101 or the Canadian Oil and Gas Evaluation Handbook (COGE Handbook) and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101 or the COGE Handbook.

The following definitions form the basis of the classification of reserves and values presented in the Sproule Report. Reserve data tables may not add due to rounding.

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable, and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgement combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. These concepts are presented and discussed in greater detail within the guidelines in Section 5.5 of the COGE Handbook.

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered 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.

**1. Proved Reserves**

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

**2. Probable Reserves**

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

**3. Possible Reserves**

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in this Annual Information Form.

Other criteria that must also be met for categorization of reserves are provided in Section 5.5.4 of the COGE Handbook.

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

**4. Developed Reserves**

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

**5. Developed Producing Reserves**

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

**6. Developed Non-Producing Reserves**

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

**7. Undeveloped Reserves**

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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 or possible) 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 is typically 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.

**8. Levels of Certainty for Reported Reserves**

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 above are applicable to individual reserves 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 reserve estimates are presented.

Reported reserves should target the following levels of certainty under a specific set of economic conditions:

a) At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
b) At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
c) At least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves plus possible reserves.

A quantitative 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 are 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 Section 5 of the COGE Handbook.

## CURRENCY

In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

## FORWARD-LOOKING STATEMENTS

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking statements. These statements relate to future events or Bonterra's future performance. All statements other than statements of historical fact may be forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. In addition, this Annual Information Form and documents incorporated by reference herein may contain forward-looking statements attributed to third party industry sources. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Forward-looking statements in this Annual Information Form and the documents incorporated by reference herein include, but are not limited to, statements with respect to:

- the quantity and quality of the oil and natural gas reserves;
- the performance and characteristics of Bonterra's oil and natural gas properties;
- future development and exploration activities and the timing thereof;
- future land expiries;
- results of various projects of Bonterra;
- timing of receipt of regulatory approvals;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of Bonterra;
- supply and demand for oil, NGLs and natural gas;
- expectations regarding Bonterra's ability to raise capital and to continually add to reserves through development and acquisitions;
- the impact of Canadian federal and provincial governmental regulation on Bonterra relative to other natural resource issuers of similar size;
- realization of the anticipated benefits of acquisitions and dispositions;
- weighting of production between different commodities;
- projections of commodity prices and costs;
- expected levels of royalty rates, operating costs, general and administrative costs, costs of services and other costs and expenses;
- capital expenditure programs and the timing and method of financing thereof; and
- treatment under government regulation and taxation regimes.

Although Bonterra believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Bonterra cannot guarantee future results, levels of activity, performance, or achievements. Moreover, neither Bonterra nor any other person assumes responsibility for the outcome of the forward-looking statements. Many of the risks and other factors are beyond Bonterra's control, which could cause results to differ materially from those expressed in the forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein. The risks and other factors include, but are not limited to:

- general economic conditions in Canada, the United States and globally, including reduced availability of debt and equity financing generally;
- industry conditions, including fluctuations in the price of oil, NGLs and natural gas;
- liabilities inherent in oil and natural gas operations;
- the ability to generate sufficient cash flow from operations and other sources to meet current and future obligations, including costs of projects and repayment of debt;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- the uncertainty of reserve estimates and reserve life;
- weather;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to realize anticipated benefits of acquisitions;
- failure to obtain industry partner and other third party consents and approvals, when required;
- health, safety and environmental risks;
- stock market volatility and market valuations;

- competition for, among other things, capital, acquisitions or reserves, deposits, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services;
- rights to surface access;
- the ability of management to execute its business plan;
- the need to obtain required approvals from regulatory authorities; and
- the other factors considered under "Risk Factors" in this Annual Information Form.

These factors should not be considered as exhaustive. Statements relating to "reserves" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources, reserves and deposits described can be profitably produced in the future. With respect to forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein, Bonterra has made assumptions regarding: future exchange rates; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; availability of skilled labour; current technology; cash flow; production rates; timing and amount of capital expenditures; the prices and marketability of oil, NGLs and natural gas; royalty rates; effects of regulation by governmental agencies; future operating costs; and the company's ability to obtain financing on acceptable terms. Readers are cautioned that the foregoing list of factors is not exhaustive.

The above summary of assumptions and risks related to forward-looking information has been provided in this Annual Information Form and the documents incorporated by reference herein in order to provide readers with a more complete perspective on Bonterra's future operations. Readers are cautioned that this information may not be appropriate for other purposes.

**The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. Bonterra is not under any duty to update or revise any of the forward-looking statements except as expressly required by applicable securities laws.**

# STRUCTURE OF BONTERRA ENERGY CORP.

## Bonterra Energy Corp.

Bonterra Energy Corp. ("Bonterra" or "the Company") is an oil and gas company headquartered in Calgary, Alberta. The Company's assets consist of crude oil and natural gas assets.

The head and principal office of Bonterra is located at:
901, 1015 4th Street S.W., Calgary, Alberta, T2R 1J4.

**Bonterra Energy Corp. is a conventional oil and gas corporation forging a grounded path forward for Canadian energy. Operations include a large, concentrated land position in Alberta's Pembina Cardium, one of Canada's largest oil plays. Bonterra's liquids-weighted Cardium production provides a foundation for implementing a return of capital strategy over time, which is focused on generating long-term, sustainable growth and value creation for shareholders. The emerging Charlie Lake and Montney resource plays are expected**

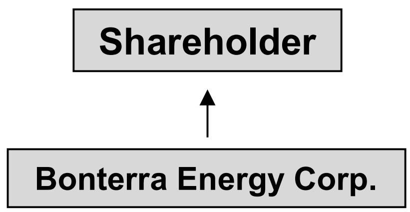
**to provide enhanced optionality and an expanded potential development runway for the future.**

## Transfer Agent and Registrar

**The Registrar and Transfer Agent for the common shares is Odyssey Trust Company at 1230, 300 5th Ave SW Calgary, Alberta T2P 3C4**

## Organization Chart

At December 31, 2024, the structure of Bonterra was as set forth below:




The common shares trade under the symbol BNE on the Toronto Stock Exchange (TSX).

Bonterra Energy Corp. was formed effective January 1, 2010 when Bonterra Oil & Gas Ltd. wound up Bonterra Energy Income Trust (“Bonterra Trust”) and amalgamated with its wholly owned subsidiary Bonterra Energy Corp. pursuant to the provisions of the Canada Business Corporations Act to continue as one corporation under the name Bonterra Energy Corp. effective January 1, 2010.

Prior to the amalgamation, Bonterra Trust (a trust which was wholly owned by Bonterra Oil & Gas Ltd.) was wound-up and dissolved in accordance with subsection 88.1 of the Income Tax Act (Canada). As a result of the amalgamation and dissolution of Bonterra Trust, Bonterra holds all of the assets formerly held by the former subsidiaries.

# GENERAL DEVELOPMENT OF THE BUSINESS

**Property and Corporate Acquisitions and Dispositions in 2024, 2023 and 2022**

On March 1, 2024, Bonterra closed an acquisition to purchase largely undeveloped petroleum and natural gas assets in northern Alberta, specifically targeting the prospective Charlie Lake formation in the Bonanza area for light oil and natural gas, for cash consideration of $23.6 million and $0.3 million in non-core land and leases, after closing adjustments. The Charlie Lake Asset Acquisition has been accounted for as an asset acquisition, which resulted in a $24.2 million increase in PP&E and the assumption of $0.3 million in decommissioning liabilities.

There were no material acquisitions or dispositions for the years ending December 31, 2023 and December 31, 2022.

**Legal Proceedings**

There are no material legal proceedings to which Bonterra is subject or which is known by the Company to be contemplated.

# STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

## PART I – DATE OF STATEMENT

The reserves data and other oil and gas information set forth below is based upon an evaluation by Sproule Associates Limited (Sproule), an independent qualified reserves evaluator within the meaning of National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) with an effective date of December 31, 2024 contained in the Sproule Report dated February 7, 2025.

## PART II– DISCLOSURE OF RESERVE DATA

The reserves data summarizes the oil, liquids and natural gas reserves of Bonterra and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data conforms to the requirements of NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Bonterra believes is important to the readers of this information. Bonterra engaged Sproule to provide an evaluation of Proved and Probable Reserves and no attempt was made to evaluate possible reserves.

**Readers should not assume 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 costs assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. For more information as to the risks involved see "*Risk Factors – Oil and Natural Gas Prices*" and "*Risk Factors – Reserves*".**

In accordance with the requirements of NI 51-101, attached hereto are the following appendices: 1) Appendix A: Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 containing certain information estimated using forecast prices and costs based on December 31, 2024 pricing assumptions; and 2) Appendix B: Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3.

### FORM 51-101F1 PART 2.1(1)
### SUMMARY OF OIL AND GAS RESERVES
### AS OF DECEMBER 31, 2024
### FORECAST PRICES AND COSTS

| | Light and Medium Crude Oil | | Conventional Natural Gas | | Natural Gas Liquids | | Total | |
|---|---|---|---|---|---|---|---|---|
| Reserves Catelgory: | Gross (MBbl) | Net (MBbl) | Gross (MMcf) | Net (MMcf) | Gross (MBbl) | Net (Mbbl) | Gross (MBoe) | Net (MBoe) |
| PROVED | | | | | | | | |
| Developed Producing | 16,218.0 | 14,130.0 | 88,641 | 82,007 | 3,394.1 | 2,915.6 | 34,385.6 | 30,713.5 |
| Developed Non-Producing | 2,144.4 | 1,927.5 | 7,254 | 6,742 | 279.6 | 243.9 | 3,633.0 | 3,295.0 |
| Undeveloped | 23,076.0 | 19,527.3 | 118,684 | 108,767 | 4,121.7 | 3,529.5 | 46,978.4 | 41,184.6 |
| TOTAL PROVED | 41,438.3 | 35,584.8 | 214,579 | 197,516 | 7,795.5 | 6,689.0 | 84,997.1 | 75,193.1 |
| PROBABLE | 10,286.0 | 7,923.1 | 53,211 | 48,021 | 1,918.6 | 1,513.9 | 21,073.1 | 17,440.5 |
| TOTAL PROVED PLUS PROBABLE | 51,724.3 | 43,508.0 | 267,790 | 245,536 | 9,714.1 | 8,202.9 | 106,070.2 | 92,633.6 |

The Company only operates in Canada.

## FORM 51-101F1 PART 2.1(2)
## SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
## AS OF DECEMBER 31, 2024
## FORECAST PRICES AND COSTS

### Net Present Values of Future Net Revenue Before Income Taxes
Discounted at (%/Year)

| ($ Millions)<br>Reserves Category[1] | 0% | 5% | 10% | 15% | 20% | Unit Value Discounted at 10%/YR ($/BOE) |
|---|---|---|---|---|---|---|
| PROVED | | | | | | |
| Developed Producing | 930,846 | 707,085 | 572,134 | 483,891 | 422,018 | 18.63 |
| Developed Non-Producing | 91,930 | 66,114 | 50,405 | 40,096 | 32,900 | 15.30 |
| Undeveloped | 995,773 | 617,634 | 403,117 | 273,456 | 190,318 | 9.79 |
| TOTAL PROVED | 2,018,549 | 1,390,833 | 1,025,656 | 797,443 | 645,236 | 13.64 |
| PROBABLE | 768,399 | 476,725 | 336,627 | 257,341 | 206,891 | 19.30 |
| TOTAL PROVED PLUS PROBABLE | 2,786,948 | 1,867,558 | 1,362,283 | 1,054,784 | 852,127 | 14.71 |

(1) Unit values are based on net reserves.

The Company only operates in Canada.

## FORM 51-101F1 PART 2.1(2)
## SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
## AS OF DECEMBER 31, 2024
## FORECAST PRICES AND COSTS

### Net Present Values of Future Net Revenue After Income Taxes
Discounted at (%/Year)

| ($ Millions)<br>Reserves Category | 0% | 5% | 10% | 15% | 20% |
|---|---|---|---|---|---|
| PROVED | | | | | |
| Developed Producing | 775,945 | 594,382 | 483,781 | 411,018 | 359,739 |
| Developed Non-Producing | 70,818 | 50,784 | 38,578 | 30,568 | 24,976 |
| Undeveloped | 761,521 | 458,510 | 285,378 | 181,202 | 115,131 |
| TOTAL PROVED | 1,608,284 | 1,103,676 | 807,737 | 622,788 | 499,846 |
| PROBABLE | 594,033 | 367,358 | 258,944 | 197,734 | 158,823 |
| TOTAL PROVED PLUS PROBABLE | 2,202,317 | 1,471,034 | 1,066,681 | 820,522 | 658,669 |

The Company only operates in Canada.

## FORM 51-101F1 PART 2.1(3)(b)
## TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
## AS OF DECEMBER 31, 2024
## FORECAST PRICES AND COSTS

| ($ Millions)<br>Reserves Catergory: | Revenue | Royalties | Operating Costs | Development Costs | Abandonment and Reclamation Costs | Future Net Revenue Before Income Taxes | Income Taxes | Future Net Revenue After Income Taxes |
|---|---|---|---|---|---|---|---|---|
| PROVED | 5,950,950 | 752,887 | 2,212,351 | 786,369 | 180,795 | 2,018,549 | 410,264 | 1,608,284 |
| PROVED PLUS PROBABLE | 7,576,193 | 1,063,597 | 2,745,011 | 791,451 | 189,187 | 2,786,948 | 584,631 | 2,202,317 |

The Company only operates in Canada

## FORM 51-101F1 PART 2.1(3)(c)
## NET PRESENT VALUE OF FUTURE NET REVENUE
## BY PRODUCTION GROUP
## AS OF DECEMBER 31, 2024
## FORECAST PRICES AND COSTS

| Reserve Category | Production Group | Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($ Millions) | Unit Value Before Income Taxes (Discounted at 10%/Year) ($/BOE)[1] |
|---|---|---|---|
| Proved | Light And Medium Crude Oil (Including solution gas and associated by-products) | 1,010,246 | 13.70 |
| | Conventional Natural Gas (Including associated by-products)[2] | 15,409 | 10.61 |
| Total | | 1,025,656 | |
| Proved Plus Probable | Light And Medium Crude Oil (Including solution gas and associated by-products) | 1,341,735 | 14.77 |
| | Conventional Natural Gas (Including associated by-products)[2] | 20,548 | 11.28 |
| Total | | 1,362,283 | |

(1) Unit values are based on net reserves.
(2) Includes corporate GCA, if applicable.

The Company only operates in Canada.

PART III – PRICING ASSUMPTIONS

Forecast Prices
The Forecast Prices used in the appendix are:

| Year | Canadian Light Sweet Crude 40° API ($Cdn/bbl) | Natural Gas AECO-C Spot ($Cdn/MMbtu) | NGL Pentanes Edmonton ($Cdn/bbl) | NGL Butanes Edmonton ($Cdn/ bbl) | NGL Propane Edmonton ($Cdn/ bbl) | Operating Cost Inflation Rate (%/Yr) | Capital Cost Inflation Rate (%/Yr) | Exchange Rate ($US/$Cdn) |
|---|---|---|---|---|---|---|---|---|
| HISTORICAL | | | | | | | | |
| 2020 | 45.39 | 2.24 | 49.85 | 21.87 | 16.31 | (5.00) | (5.00) | 0.75 |
| 2021 | 80.31 | 3.64 | 85.88 | 51.64 | 43.39 | 4.00 | 8.00 | 0.80 |
| 2022 | 119.79 | 5.43 | 121.28 | 61.68 | 50.11 | 9.00 | 12.00 | 0.76 |
| 2023 | 99.87 | 2.64 | 102.80 | 45.62 | 29.59 | 5.00 | 5.00 | 0.74 |
| 2024 | 98.13 | 1.38 | 100.64 | 48.42 | 30.41 | 2.00 | - | 0.73 |
| FORECAST[(1)(2)] | | | | | | | | |
| 2025 | 94.79 | 2.36 | 100.14 | 51.15 | 33.56 | - | - | 0.71 |
| 2026 | 97.04 | 3.33 | 100.72 | 49.99 | 32.78 | 0.67 | 2.00 | 0.73 |
| 2027 | 97.37 | 3.48 | 100.24 | 50.16 | 32.81 | 2.00 | 2.00 | 0.74 |
| 2028 | 99.80 | 3.69 | 102.73 | 51.41 | 33.63 | 2.00 | 2.00 | 0.74 |
| 2029 | 101.79 | 3.76 | 104.79 | 52.44 | 34.30 | 2.00 | 2.00 | 0.74 |
| 2030 | 103.83 | 3.83 | 106.86 | 53.49 | 34.99 | 2.00 | 2.00 | 0.74 |
| 2031 | 105.91 | 3.91 | 109.01 | 54.56 | 35.69 | 2.00 | 2.00 | 0.74 |
| 2032 | 108.03 | 3.99 | 111.19 | 55.65 | 36.40 | 2.00 | 2.00 | 0.74 |
| 2033 | 110.19 | 4.07 | 113.42 | 56.76 | 37.13 | 2.00 | 2.00 | 0.74 |
| 2034 | 112.39 | 4.15 | 115.69 | 57.90 | 37.87 | 2.00 | 2.00 | 0.74 |
| 2035 | 114.64 | 4.23 | 118.00 | 59.05 | 38.63 | 2.00 | 2.00 | 0.74 |

(1) Crude oil, natural gas and liquid prices escalate at 2.0 percent thereafter.
(2) The forecasted of product prices is an average of independent reserve evaluators Sproule, GLJ Petroleum Consultants and McDaniel & Associates Consultants Ltd.

The Company's weighted average realized prices by production type for the 2024 financial year are as follows:

| | |
|---|---|
| Light and Medium Crude Oil ($ per barrel) | 94.35 |
| Conventional Natural Gas ($ per Mcf) | 1.68 |
| Natural Gas Liquids ($ per barrel) | 46.97 |

## PART IV – RECONCILIATION OF CHANGES IN RESERVES

### RECONCILIATION OF COMPANY GROSS RESERVES (BEFORE ROYALTY)
### BY PRINCIPAL PRODUCT TYPE
### AS OF DECEMBER 31, 2024
### FORECAST PRICES AND COSTS

| | Light and Medium Crude Oil (MBbl) | Conventional Natural Gas (MMcf) | Natural Gas Liquids (MBbl) | Total (MBOE) |
|---|---|---|---|---|
| **PROVED** | | | | |
| **December 31, 2023** | **42,205.4** | **184,761.0** | **7,142.3** | **80,141.1** |
| Extensions[(1)] | 1,719.1 | 25,077.0 | 685.0 | 6,583.6 |
| Acquisitions | 1,237.2 | 12,458.0 | 249.2 | 3,562.7 |
| Economic Factors | 145.5 | (873.0) | (31.6) | (31.7) |
| Technical Revisions | (1,439.0) | 7,857.0 | 304.4 | 174.9 |
| Production | (2,429.9) | (14,700.0) | (553.7) | (5,433.6) |
| **December 31, 2024** | **41,438.3** | **214,580.0** | **7,795.5** | **84,997.1** |
| **PROBABLE** | | | | |
| **December 31, 2023** | **10,949.3** | **46,977.0** | **1,826.8** | **20,605.6** |
| Extensions[(1)] | 444.5 | 6,548.0 | 178.1 | 1,714.0 |
| Acquisitions | 356.6 | 3,663.0 | 73.3 | 1,040.3 |
| Economic Factors | (110.7) | (229.0) | (8.0) | (156.9) |
| Technical Revisions | (1,353.7) | (3,747.0) | (151.6) | (2,129.8) |
| **December 31, 2024** | **10,286.0** | **53,211.0** | **1,918.6** | **21,073.1** |
| **PROVED PLUS PROBABLE** | | | | |
| **December 31, 2023** | **53,154.7** | **231,737.0** | **8,969.1** | **100,746.7** |
| Extensions[(1)] | 2,163.6 | 31,625.0 | 863.1 | 8,297.6 |
| Acquisitions | 1,593.8 | 16,120.0 | 322.4 | 4,602.9 |
| Technical Revisions | (2,797.7) | 4,110.0 | 152.8 | (1,954.9) |
| Economic Factors | 34.8 | (1,103.0) | (39.6) | (188.6) |
| Production | (2,429.9) | (14,700.0) | (553.7) | (5,433.6) |
| **December 31, 2024** | **51,724.3** | **267,790.0** | **9,714.1** | **106,070.2** |

(1) Included in extensions is infill drilling.

The Company only operates in Canada.

# PART V – ADDITIONAL INFORMATION RELATED TO RESERVE DATA

Undeveloped Reserves

Company Gross Reserves – First Attributed by Year [(1)]

Proved Undeveloped Reserves

| | Light and Medium Crude Oil (MBbl) | | Conventional Natural Gas (MMcf) | | Natural Gas Liquids (MBbl) | | Total (MBOE) | |
|---|---|---|---|---|---|---|---|---|
| | First Attributed | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End |
| 2022 | 4,212 | 22,699 | 12,162 | 99,792 | 547 | 3,869 | 6,787 | 43,201 |
| 2023 | 4,195 | 23,245 | 14,900 | 91,458 | 638 | 3,633 | 7,316 | 42,121 |
| 2024 | 2,264 | 23,076 | 29,951 | 118,684 | 752 | 4,122 | 8,008 | 46,978 |

Probable Undeveloped Reserves

| | Light and Medium Crude Oil (MBbl) | | Conventional Natural Gas (MMcf) | | Natural Gas Liquids (MBbl) | | Total (MBOE) | |
|---|---|---|---|---|---|---|---|---|
| | First Attributed | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End | First Attributed | Total at Year End |
| 2022 | 1,010 | 5,681 | 2,922 | 24,957 | 133 | 965 | 1,629 | 10,806 |
| 2023 | 1,280 | 6,112 | 4,111 | 23,215 | 175 | 931 | 2,140 | 10,912 |
| 2024 | 589 | 5,983 | 7,813 | 29,520 | 195 | 1,023 | 2,086 | 11,926 |

(1) First attributed refers to reserves first attributed at year end of the corresponding fiscal year.

Sproule's evaluation of Bonterra's reserves as of December 31, 2024 is in accordance with the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook").

Bonterra's proved undeveloped reserves amount to 46,978 MBOE and represent approximately 55.3 percent of the total proved reserves and 44.3 percent of total proved plus probable reserves. 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. In general, proved undeveloped reserves were assigned to certain properties as a result of Bonterra's capital program. Bonterra plans to convert the undeveloped reserves to proved developed producing reserves over the next five years.

Bonterra's probable undeveloped reserves amount to 11,926 MBOE and represent approximately 11.2 percent of the total proved plus probable reserves. Probable undeveloped reserves are assigned for similar reasons and generally to the same properties as proved undeveloped reserves. 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.

Bonterra's proved plus probable undeveloped reserves are primarily comprised of Cardium horizontal locations.

Significant Factors or Uncertainties

For significant factors and uncertainties affecting components of reserves data please see discussions under "Risk Factors" in this Annual Information Form and "Management's Discussion and Analysis" as contained in the Company's 2024 Annual Report.

Future Development Costs

| $ 000s | Prices and Costs | |
|---|---|---|
| Year | Proved | Proved Plus Probable |
| 2025 | 47,603 | 47,655 |
| 2026 | 160,946 | 160,997 |
| 2027 | 173,973 | 173,973 |
| 2028 | 196,356 | 196,356 |
| 2029 | 207,490 | 212,470 |
| Total Undiscounted | 786,369 | 791,451 |

The above future development costs will be funded primarily from 2025 to 2029 cash flow from operations and if required from the Company's line of credit. Should these sources of funds be insufficient the Company will access the public markets as required.

# PART VI – OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

All of Bonterra's oil and natural gas properties are primarily located in the Province of Alberta. The Company also has non-core properties located in the Provinces of Saskatchewan and British Columbia. In 2024, production volumes from Bonterra's properties were approximately 55 percent light and medium crude oil and NGLs and 45 percent conventional natural gas on a BOE basis. During the year ended December 31, 2024, Bonterra's oil and natural gas properties yielded average annual production of 14,846 BOE per day (2023 – 14,204 BOE per day, 2022 – 13,407 BOE per day). As at December 31, 2024 the oil and natural gas property interests held by Bonterra are estimated to contain Proved plus Probable Reserves of 106,070 MBOE.

**Pembina and Willesden Green, West Central Alberta**

The Company's principal asset is a large, geographically concentrated position of 312 net sections held predominantly in the Pembina and Willesden Green fields. Combined, these fields are the Company's largest producing asset.

The Pembina Cardium field is the largest conventional oil field in Canada containing an estimate of original oil in place (OOIP) of 10.6 billion barrels with less than 20 percent produced to date. This field has proven to be a significant area for multi-zone oil and natural gas exploration with predictable results. Horizontal drilling with multistage fracking improves recoveries from areas historically developed with vertical drilling and extends the economic edges of the reservoir. The Cardium asset offers predictable and stable production, quality light oil and robust netbacks. Bonterra operates approximately 93% of its Cardium production and has ownership and operates the majority of the related oil and gas processing facilities. Production from the Cardium assets is primarily light crude oil (55% oil and NGLs) ranging from 35° to 38° API. The Cardium area presently represents approximately 90% of Bonterra's total corporate 2P NPV10 value as independently evaluated by Sproule.

Some benefits of the Cardium area include:

- located in a large, well established oil producing fairway in Western Canada;
- predictable results and per well economics that support quick payouts;

- conventional sandstone reservoirs that support good capital efficiencies;
- shallow depth (~1,500 metres);
- low geological risk due to thousands of vertical penetrations; and
- geographic concentration improves operational efficiencies.

Bonterra's 2024 production from the Cardium assets was approximately 13,690 boe per day (55% oil and NGLs) representing approximately 90% of the Corporation's production. In 2024, the Company drilled 20 gross (15.1 net) horizontal Cardium oil wells and placed 24 gross (18.7 net) wells on production, of which 4 gross (3.6 net) horizontal Cardium wells were drilled in Q4 2023. In 2025 the Corporation expects to drill and complete 16 gross (6.3 net) horizontal wells while also heavily focusing on improving operational efficiencies to enhance free funds flow generation of the asset.

Facilities

Bonterra operates approximately 54 oil batteries of various capacities in the Pembina area. Oil is gathered via pipeline or trucked to the batteries for processing. Treated oil is transferred into the Pembina midstream gathering system for transportation to Edmonton. Solution gas is separated at the batteries and pipeline connected to either four gas plants the Company operates or other non-operated gas plants, most of which Bonterra has ownership in.

**Bonanza Charlie Lake, Northern Alberta**

The Bonanza Charlie Lake field is Bonterra's second and newest core area located in northwest Alberta. The Company has been building a land base in the region since 2022 and most recently, in March of 2024, completed a key acquisition to solidify it as a new core area. The Company now has a contiguous 118 sections of land with an average working interest greater than 90%. Since the closing of the acquisition the Company has drilled, completed, equipped, tied in and brought 4 gross (3.6 net) Charlie Lake horizontal wells on production.

Production from the Charlie Lake assets is primarily light crude oil (56% oil and NGLs) ranging from 38° to 40° API. The Company anticipates the Charlie Lake to become the growth engine of the Company and provide steady reserve growth into the future.

Some benefits of the Charlie Lake area include:

- organic growth opportunities;
- per well economics that support quick payouts and exceptional capital efficiencies; and
- shallow depth (~1,350 metres).

The Charlie Lake asset provides the Company with a long-term light oil development runway with highly economic horizontal drilling inventory. Quick payouts and superior capital efficiencies from these locations are expected to enhance the Corporation's free funds flow generating capacity and enhance corporate sustainability.

**Valhalla Montney, Northern Alberta**

The Valhalla Montney field is an emerging light oil resource play in Bonterra's portfolio located Northeast of Grande Prairie, Alberta. The Company began building a land base in the region in 2019 and has since assembled 52 contiguous sections of 100% working interest land. The Montney is recognized as one of Canada's highest impact and most economic plays and is expected to provide the Company with a large development runway, scalable reserve growth and significant production growth potential.

In 2024 the Company drilled 1 gross (1.0 net) well, placed 2 gross (2.0 net) Montney wells on production and constructed its first facility in the region, a 100% owned battery (100%).

Production from the Montney asset is light crude oil, natural gas liquids and natural gas (41% oil and natural gas liquids), with oil quality ranging from 39° to 40° API. The Montney production is flowing to an industry partner natural gas processing facility on an interruptible basis which has sufficient estimated capacity to flow both wells on an unrestricted basis. The Montney is expected to provide steady reserve growth into the future as the Corporation delineates the land base and begins to book locations.

Some benefits of the Montney area include:

- significant potential light oil drilling inventory;
- organic, high impact production and reserve growth potential;
- favorable land tenure situation; and
- medium depth (~1,950 metres).

The Montney asset provides exceptional optionality to the Corporation, providing a long-term light oil development runway with highly economic horizontal drilling inventory in a world class resource play.

**Shaunavon Area, Southwest Saskatchewan**

Properties

Bonterra's Shaunavon properties are located in the Chambery field and produce medium density crude oil from the upper Shaunavon formation currently under waterflood. Average annual production for 2024 was 66 BOE per day (net). The wells in this area are generally long-life with stable and low-decline production profiles.

Facilities

Bonterra has ownership in all facilities required to process its Shaunavon production. All oil production is processed through owned and operated facilities for emulsion treating and water disposal. All natural gas produced is used for fuel gas in the production and processing of the oil, therefore, no processing facilities are required for processing solution gas.

The Company disposed of its interest in the Shaunavon area assets in the first quarter of 2025.

**Prespatou Area, Northeast British Columbia**

The Prespatou area of northeast British Columbia (NEBC) consists almost entirely of natural gas and associated natural gas liquids with average annual production of approximately 25 BOE per day for 2024. The Company is currently restricted due to a third-party sales line failure. The third-party sales line failure is not expected to be remedied in 2025.

Facilities

The NEBC area production feeds into one of three compressor stations prior to reaching non-operated gas plants for sales. Bonterra has ownership in these operated and non-operated facilities with working interests varying from 0 to 100 percent. Bonterra has operatorship of the compressor station that receives most of its NEBC production. After the gas is gathered and compressed through these gathering systems and compression facilities, it is delivered to either the Spectra Energy gas transmission pipeline for transportation to the McMahon gas plant or the CNRL gas gathering system located east of Fort St. John for treating and processing.

## Well Count

The wells in which Bonterra had an interest as at December 31, 2024 that it considers capable of production are set out in the following table:

| | Producing Wells | | | | Non-Producing Wells | | | | Total | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Oil Wells | | Gas Wells | | Oil Wells | | Gas Wells | | Oil Wells | | Gas Wells | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| AB | 1,113 | 742.8 | 116 | 24.9 | 583 | 347.8 | 43 | 24.5 | 1,696 | 1,090.7 | 159 | 49.5 |
| BC | 25 | 18.1 | - | - | - | - | - | - | 25 | 18.1 | - | - |
| SK | - | - | 14 | 4.1 | - | - | 61 | 22.0 | - | - | 75 | 26.1 |
| Total | 1,138 | 761.0 | 130 | 29.0 | 583 | 347.8 | 104 | 46.6 | 1,721 | 1,108.8 | 234 | 75.6 |

## Properties with No Attributable Reserves

Bonterra's properties with no attributable reserves consist of approximately 109,470 gross and 80,403 net undeveloped acres in 2024.

Expiring acreage in the next twelve months consists of 640 gross (640 net) acres. The Company will continue to maximize their value and actively manage pending expiries.

The Company is currently reviewing these properties with a focus on maximizing their value.

## Financial Risk Management

The Company utilizes a range of financial risk management contracts to mitigate commodity price risk, including physical delivery sales and risk management contracts that establish price parameters for a portion of its production. Through its hedging program, the Company actively manages price risk by employing both physical and financial contracts, with contracted volumes ranging from 30% to 50% for oil and natural gas (net of royalties payable), on terms primarily lasting from 9 to 12 months from each reporting period.

Additional Information Concerning Abandonment and Reclamation Costs

In connection with its operations, the Company will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The Company budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. The Company estimates such costs through a model that incorporates data from the Company's operating history, industry sources and cost formulas used by Alberta Energy Regulator, together with other operating assumptions. The Company expects all of its net wells to incur these costs. The Company anticipates the total amount of such costs, excluding inflation, to be approximately $179.4 million on an undiscounted basis and $47.5 million with inflation at approximately 2% and discounted at 10% in accordance with NI 51-101. These incurred abandonment and reclamation obligations are included in the calculations of future net revenue associated with proved plus probable developed reserves under "Oil and Natural Gas Reserves" in this Annual Information Form.

Also included in this Annual Information under "Oil and Natural Gas Reserves" are the calculations of future net revenue associated with proved plus probable reserves. In addition to the estimated future abandonment and reclamation costs of proved plus probable developed reserves above, is the abandonment and reclamation of proved plus probable undeveloped reserves that includes the obligation of future wells and facilities that has not yet occurred. The Company estimates the costs associated with the abandonment and reclamation obligations that has not occurred to be approximately $36.9 million on an uninflated and undiscounted basis and $1.3 million with inflation at approximately 2% and discounted at 10%.

In the next three financial years, the Company anticipates that a total of approximately $15.4 million on an uninflated and undiscounted basis and $13.0 million with inflation at approximately 2% and discounted at 10% will be incurred in respect of abandonment and reclamation costs.

Tax Horizon

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

| ($ 000s) | Rate of Utilization (%) | Amount |
|---|---|---|
| Undepreciated capital costs | 7-100 | 78,299 |
| Share issue costs | 20 | 3,109 |
| Canadian oil and gas property expenditures | 10 | 72,605 |
| Canadian development expenditures | 30 | 125,387 |
| Canadian exploration expenditures | 100 | 8,587 |
| | | 287,987 |

The Company has $64,111,000 (December 31, 2023 - $64,725,000) of capital losses carried forward which can only be claimed against taxable capital gains.

Capital Expenditures Incurred

The following table summarizes petroleum and natural gas capital expenditures incurred by Bonterra on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

| ($ 000s) | 2024 | 2023 |
|---|---|---|
| Land | 1,190 | 1,222 |
| Acquisitions - Oil and Gas property | 24,234 | - |
| Exploration and development costs | 99,886 | 125,255 |
| Net petroleum and natural gas capital expenditures | 125,310 | 126,477 |

Exploration and Development Activities

The following tables summarize Bonterra's gross and net drilling activity and success:

| | 2024 | | | | | |
|---|---|---|---|---|---|---|
| | Development | | Exploratory | | Total | |
| | Gross | Net | Gross | Net | Gross | Net |
| Oil wells | 23 | 18.5 | - | - | 23 | 18.5 |
| Natural gas wells | 1 | 1.0 | | | 1 | 1.0 |
| Dry wells | - | - | - | - | - | - |
| Total | 24 | 19.5 | - | - | 24 | 19.5 |
| Success rate | 100% | 100% | 100% | 100% | 100% | 100% |

| | 2023 | | | | | |
|---|---|---|---|---|---|---|
| | Development | | Exploratory | | Total | |
| | Gross | Net | Gross | Net | Gross | Net |
| Oil wells | 52 | 41.2 | - | - | 52 | 41.2 |
| Natural gas wells | - | - | 1.0 | 1.0 | 1 | 1.0 |
| Dry wells | - | - | - | - | - | - |
| Total | 52 | 41.2 | 1.0 | 1.0 | 53 | 42.2 |
| Success rate | 100% | 100% | 100.0 | 100.0 | 100% | 100% |

Please see discussion under Undeveloped Reserves for important current and likely exploration and development activities.

Production Estimates 2025

| | 2025 | | | |
|---|---|---|---|---|
| | Light and Medium Crude Oil (Bbl/d) | Conventional Natural Gas (Mcf/d) | NGLs (Bbl/d) | Total (BOE/d) |
| Alberta[1] | 7,158 | 47,847 | 1,667 | 16,801 |
| British Columbia | - | - | - | - |
| Saskatchewan | 46 | - | - | 46 |
| | 7,205 | 47,846 | 1,667 | 16,847 |

(1) Substantially all of Alberta's production is from the Pembina, Willesden Green and Charlie Lake fields.

The above production estimates are based on the proved and probable reserve estimates using forecasted prices and costs contained in the Sproule Report.

Production History 2024

| Product Type Yearly Quarter | Production Volume per day | Average per Unit of Volume ($/Bbl and $/Mcf) Price | Royalties | Production Costs | Netbacks |
|---|---|---|---|---|---|
| Light and Medium Crude Oil (Bbl) | | | | | |
| 1 Quarter | 6,622 | 88.96 | 6.98 | 28.23 | 53.75 |
| 2 Quarter | 6,571 | 102.09 | 7.97 | 22.46 | 71.66 |
| 3 Quarter | 6,775 | 94.30 | 7.66 | 24.97 | 61.67 |
| 4 Quarter | 6,588 | 92.11 | 6.62 | 26.74 | 58.75 |
| Conventional Natural Gas (Mcf) | | | | | |
| 1 Quarter | 36,594 | 2.65 | 1.16 | 1.36 | 0.13 |
| 2 Quarter | 37,519 | 1.64 | 1.33 | 1.38 | (1.07) |
| 3 Quarter | 42,039 | 0.96 | 1.28 | 1.41 | (1.73) |
| 4 Quarter | 44,436 | 1.60 | 1.10 | 1.30 | (0.80) |
| Natural Gas Liquids (Bbl) | | | | | |
| 1 Quarter | 1,468 | 46.08 | 6.98 | 12.50 | 26.60 |
| 2 Quarter | 1,418 | 45.08 | 7.97 | 21.96 | 15.15 |
| 3 Quarter | 1,538 | 47.44 | 7.66 | 11.24 | 28.54 |
| 4 Quarter | 1,625 | 48.97 | 6.62 | 10.50 | 31.85 |

The following table provides a summary of the average production volumes from Bonterra's producing areas.

| | 2024 | | |
|---|---|---|---|
| | Light and Medium Crude Oil and NGL (Bbl per day) | Conventional Natural Gas (Mcf per day) | Total (BOE per day) |
| Alberta | 8,086 | 40,016 | 14,755 |
| Saskatchewan | 62 | 26 | 66 |
| British Columbia | 4 | 123 | 25 |
| | 8,152 | 40,165 | 14,846 |

Lease Holdings

Bonterra's holdings of petroleum and natural gas leases and rights are as follows:

| | 2024 | | 2023 | |
|---|---|---|---|---|
| | Gross Acres | Net Acres | Gross Acres | Net Acres |
| Alberta | 408,928 | 282,482 | 354,928 | 227,663 |
| Saskatchewan | 5,842 | 3,704 | 5,886 | 3,677 |
| British Columbia | 65,208 | 28,257 | 65,913 | 28,297 |
| | 479,978 | 314,443 | 426,727 | 259,636 |

# INFORMATION RESPECTING BONTERRA ENERGY CORP.

**Operations of Bonterra Energy Corp.**

*Management Policies and Acquisition Strategy*

The objectives of the management of Bonterra are to maximize total return to shareholders over the long-term by growing production, debt reduction and potentially returning to cash dividends to shareholders. These objectives are met through the optimum utilization and development of existing crude oil and natural gas properties and acquisition or development of new producing or undeveloped properties.

Bonterra selectively acquires producing and non-producing oil and natural gas properties with exploration, development or operational enhancement opportunities. The development and exploration opportunities acquired are generally of a low risk nature. Where higher risk oil and gas prospects are acquired as part of a package of properties, Bonterra may sell, farm out or develop the exploration prospects, depending on management's assessment of the prospects' potential, costs involved and Bonterra's own technical expertise.

*Return of Capital*

Bonterra historically paid monthly dividends, prior to the onset of the COVID-19 pandemic. On March 10, 2020, the Company’s Board of Directors elected to suspend its monthly dividend, commencing on April 1, 2020. The Company is planning to implement a return of capital depending on commodity prices.

See "Dividends to Shareholders" for the past cash dividends made or declared to shareholders of Bonterra.

*Environmental Obligations*

Bonterra emphasizes the importance of creating and maintaining a safe and environmentally sound operation. The Company focuses on having management involvement in establishing safety policies, proper training of field operators, continuous and thorough review of operating procedures and policies conducted by the field operation's staff and management and by monitoring and ensuring compliance with safety and environmental regulations.

*Acquisition Due Diligence*

Bonterra conducts due diligence on all prospective acquisitions. Site inspections and file reviews are conducted by an internal team. Potential contamination and operational issues are identified at this stage to help protect Bonterra from purchasing properties with significant environmental liabilities.

*Spill and Incident Control*

Bonterra field operators and staff are required to report all spills, incidents and near misses to the management of Bonterra for review and to the regulatory agency when required. The investigation of all such incidents allows Bonterra, including management, to determine the factors responsible and assist in the identification of other similar situations prior to incidents occurring and ensuring proper actions are taken. Overall, Bonterra is confident that the program will reduce the occurrence of spills and assist in reducing future losses.

*Insurance*

Bonterra carries insurance coverage to protect its assets. Insurance coverage is subject to policy limitations and deductibles. Coverage is determined and placed by Bonterra subsequent to giving consideration to the perceived risk of loss, limit of coverage determined appropriate and the cost of coverage. Coverage currently in place includes protection against third party liability and pollution, property damage or loss, director and officer liability and business interruption.

*Borrowing*

The Company's debt obligations consist of a bank facility, a subordinated term debt and subordinated debentures. Details of the banking arrangement is contained in Note 8 of Bonterra's audited annual financial statements for the year ended December 31, 2024, contained in the Company's 2024 Annual Report. The financial statements and management discussion and analysis are incorporated herein for reference.

*Personnel*

At the date of this report, Bonterra employed a total of 41 persons and contracted numerous office and field operations personnel.

# INDUSTRY CONDITIONS

**Production and Operation Regulations**

The oil and natural gas industry is subject to extensive controls, laws and regulations imposed by various levels of government. These laws and regulations may be changed in response to economic or political conditions, and regulate among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations. While it is not expected that any of these controls or regulations will affect the operations of the Company in a manner materially different than they would affect other oil and gas corporations of similar size, the controls and regulations should be considered carefully by investors. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Western Canada.

**Pricing and Marketing in Canada**

*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; 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.

*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.

**Transportation Constraints, Pipeline Capacity and Market Access**

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 the Trans Mountain pipeline expansion has been completed, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors.

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.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and, under the Canadian Energy Regulator Act ("CERA"), new interprovincial and international pipelines require a federal regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of this regulatory uncertainty, the Canadian 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 pipeline projects.

*Oil Pipelines*

Following years of legal and regulatory proceedings, construction challenges and delays, the Trans Mountain Pipeline expansion commenced commercial operations on May 1, 2024, tripling the capacity of the pipeline and adding an additional 590,000 barrels per day of shipping capability. This accounts for 17 percent of the total pipeline export capacity available to Canadian crude oil shippers, according to the Canadian Energy Regulator ("CER").

*Natural Gas and Liquefied Natural Gas*

Natural gas prices in Alberta and British Columbia 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 is generally lower than the prices received in other North American regions.

In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "NGTL System"). The NGTL System has a $9.9 billion infrastructure program underway, to add 3.5 billion cubic feet per day of incremental delivery capacity.

In October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline. Phase 1 of the LNG Canada project is over 95% complete and the facility is on track to deliver first cargoes by the middle of 2025. LNG Canada eventually plans to double the facility's capacity with a proposed Phase 2 expansion.

In June 2024 the proposed Cedar LNG project, a floating LNG facility also located in British Columbia, reached a successful final investment decision, and is expected to be in service in late 2028.

**International Trade Agreements**

In 2020, the North American Free Trade Agreement ("NAFTA") that previously existed among the governments of Canada, the United States and Mexico was replaced by a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "USMCA") and sometimes referred to as the Canada United States Mexico Agreement or CUSMA. The USMCA requires the three signatory countries to hold a joint review of the agreement every six years. The next review is scheduled for July 1, 2026. As the United States remains Canada’s primary trading partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, any changes to the USMCA could have an impact on Western Canada’s petroleum and natural gas industry at large, including the Company's business.

On February 1, 2025, President Trump signed an executive order imposing a 25% tariff on all goods originating in Canada and imported into the United States and a 10% tariff on “energy and energy resources” from Canada. The tariffs became effective on March 4, 2025. In response, the Government of Canada imposed 25% tariffs on $155 billion in goods imported from the U.S., coming into effect in two phases starting on March 4, 2025. On March 6, 2025, the U.S. agreed to delay the imposition of their tariffs on imported goods subject to the USMCA until April 2, 2025. Although discussions continue regarding a potential economic arrangement between the two countries, there remains significant uncertainty over whether tariffs or other restrictive trade measures or countermeasures will be implemented and, if so, the scope, impact, and duration of any such measures.

Canada has also pursued a number of other international free trade agreements with other countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. Canada and the European Union agreed to the Comprehensive Economic and Trade Agreement ("CETA"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. Following the United Kingdom's departure from the European Union (Brexit) on January 31, 2020, the United Kingdom and Canada agreed to an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity

Agreement ("CUKTCA"). The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship. On January 25, 2024, the United Kingdom formally notified Canada that it had paused negotiations for a new free trade agreement, though the CUKTCA remains in force.

Canada and ten other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("CPTPP") which allows for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among Canada and ten other countries in the Indo-Pacific: Australia, Brunei, Chile, Japan, Malaysia, Mexico, New Zealand, Peru, Singapore and Vietnam. The CPTPP facilitates temporary entry to Canada for certain categories of business persons who are citizens of other countries which are signatories to the CPTPP.

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

**Land Tenure**

Rights are granted to energy companies to explore for and produce oil, bitumen and natural gas pursuant to leases, licenses, permits and regulations as legislated by the respective provincial and federal governments. Lease terms vary in length, usually from two to five years for oil and natural gas leases, and usually 15 years for Alberta bitumen leases. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Lands in an oil and natural gas lease are continued beyond their primary term by drilling a well(s). A lease is proven productive at the end of its primary 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 the initial term of the lease. The tenure only comes to an end when the holder can no longer prove its agreement is capable of producing oil or gas.

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

Oil and natural gas can also be privately owned (freehold) and rights to explore for and produce such oil and natural gas are granted by leases on such terms and conditions as may be negotiated between the landowner and the lessee.

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

**Surface Rights**

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, facility or pipeline.

## 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 subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. 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 often provide for royalty reductions, credits and 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, including, but 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, have been 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.

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

*Alberta - Royalties*

In terms of oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. In respect of 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.

In 2016, the Government of Alberta adopted the Modernized Royalty Framework for Alberta ("MRF" or the "Modernized Framework"). The 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 Modernized Framework. On July 12, 2016, the Government of Alberta announced that producers could apply for early adoption of the MRF in respect of wells spud between July 13, 2016 and December 31, 2016. As of January 1, 2027, these older wells will become subject to the Modernized Framework. 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 percent of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative 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 Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, 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 percent. Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40 percent for pentanes and 30 percent 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.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner.

Freehold mineral taxes are levied annually for production from freehold mineral lands. On average, the tax levied in Alberta is 4 percent of revenues reported from freehold mineral title properties. Freehold mineral taxes are in addition to any other negotiated royalty or other payment required to be paid to the owner of such freehold mineral rights.

*Saskatchewan - Royalties*

The amount payable as a royalty with respect to oil depends on the type and vintage of the oil, the quality of the oil produced in the month and the value of the oil determined monthly by the provincial government. Each month, royalty rates are adjusted based on reference prices established by the Province for each type of oil. There are separate reference prices established for each type of oil (heavy oil, Southwest designated oil, or non-heavy oil other than Southwest designated oil) which represents the average well head price received by producers during the month for sales of that oil type in Saskatchewan.

The Government of Saskatchewan has introduced the Oil and Gas Orphan Fund, funded by oil and gas companies to cover the cost of cleaning up abandoned wells and facilities where the owner cannot be located or has gone out of business. The program is composed of a security deposit, based upon a formula considering assets of the well and the facility licensee against the estimated cost of decommissioning the well and facility once it is no longer producing, and an annual levy assessed to each licensee.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells. On April 1, 2021, the Minister of Energy and Resources implemented an Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax on associated natural gas produced from wells other than natural gas wells, including natural gas produced from oil wells. The moratorium is in connection with the Government of Saskatchewan's Growth Plan and is aimed at meeting the Government of Saskatchewan's regulatory obligations to reduce methane-based greenhouse gas ("GHG") emissions by 40 to 45% between 2020 and 2025. The Associated Gas Royalty Moratorium is applicable to natural gas produced on or after April 1, 2021 and before April 1, 2026.

The Government of Saskatchewan also has a drilling incentive whereby qualifying incentive volumes of newly drilled oil wells are subject to a maximum royalty rate of 2.5% for Crown production and a maximum production tax rate of 0% for freehold production.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

*British Columbia - Royalties*

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGLs in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGLs and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGLs and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will thus vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare depending on the total number of hectares owned by the entity.

In May 2022, the government of British Columbia introduced a new royalty framework with price-sensitive royalty rates ranging from 5% to 40% depending on the commodity type. The new royalty framework will take effect on January 1, 2027. For natural gas wells with a spud date from September 1, 2022 to August 31, 2024, a flat 5% royalty rate is payable for the equivalent of the first 12 production months (8,760 production hours). At the end of this period, these wells pay royalties based on the current royalty system until the new price-sensitive rates takes effect on January 1, 2027.

For new natural gas wells with a spud date on or after September 1, 2024, a flat 5% royalty rate is payable for the equivalent of the first 12 production months (8,760 production hours). After the initial production period, such well will be evaluated based on volumes produced during this period. Depending on production, the natural gas well will either revert to the current royalty framework or, if qualified as a dry natural gas well, be granted an additional five producing months at a 5% royalty, after which the new price-sensitive royalty rates will apply.

For new oil wells with a spud date on or after September 1, 2024, a flat 5% royalty rate is payable for the first six production months (4,380 production hours). At the end of this period, these wells will fall under the current royalty framework until December 31, 2026. On January 1, 2027, the new price-sensitive royalty rates will apply.

***Freehold and Other Types of Non-Crown Royalties***

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

**Regulatory Authorities and 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 and storage, habitat protection and the satisfactory operation, maintenance, abandonment 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 emissions, may impose further requirements on operators and other companies in the oil and natural gas industry. Companies that have hydraulic fracturing operations have additional operational regulatory and reporting requirements.

Bonterra 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 employs an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental 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 government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport 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.

*Impact Assessment Act*

The CER is responsible for the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency of Canada (the "IA Agency") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency.

Once a review or assessment is commenced under either the CERA or Impact Assessment Act, there are limits on the amount of time the CER and/or IA Agency will have to issue their report(s) and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

*Clean Fuel Regulations*

The Clean Fuel Regulations ("CFR") are a set of rules and requirements implemented by the federal government to achieve its objective of reducing GHG emissions. The CFR requires liquid fossil fuel primary suppliers to reduce the carbon intensity of the liquid fossil fuels they produce in, and import into, Canada. The CFR has also established a credit market, whereby the annual carbon intensity reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the carbon intensity of the fossil fuel throughout its lifecycle; (ii) supplying low-carbon fuels; and (iii) specified end-use fuel switching in transportation.

*Regulations Amending the Output-Based Pricing System Regulations and the Environmental Violations Administrative Monetary Penalties Regulation*

On November 22, 2023, the federal government published amendments to the Output-based Pricing System ("OBPS"). These regulations are made under the Greenhouse Gas Pollution Pricing Act ("GGPPA"). These amendments ensure continued greenhouse gas emissions reductions, reduce the administrative burden, and improve the implementation of the OBPS Regulations. Notably, the updated OBPS introduced a 2% fixed annual tightening rate for most Standards starting from 2023. Sectors facing significant competition and carbon pricing-induced carbon leakage experienced a 1% adjusted tightening rate from 2023 onwards. Additionally, the publication of the Quantification Methods for the Output-Based Pricing System Regulations ("OBPS QM"), detailing emissions quantification methods, was released on December 12, 2023. The OBPS QM establishes the required methods for quantifying greenhouse gases, heat ratios, and electricity generated within the OBPS framework.

*Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap*

On November 4, 2024, the federal government proposed the Proposed Emissions Cap Regulations. The Proposed Emissions Cap Regulations would establish a cap-and-trade system that would apply to a wide range of industrial activities within the oil and gas sector, including onshore and offshore oil and gas production, oil sands production and upgrading, natural gas production and processing and LNG production. Under the cap-and-trade system, the federal government would determine a maximum threshold for annual emissions and freely issue emissions allowances in an amount equal to the cap. The initial cap would be based on 2026 emissions (attributed according to a formula set out in the Proposed Emissions Cap Regulations). The cap for the first compliance period, from 2030 to 2032, will be 27% below 2026 attributed emission levels for affected facilities. This reduction is anticipated to correspond to a 35% decrease from 2019 emission levels.

By December 31, 2025, operators of all existing prescribed oil and gas facilities would be required to register with the Department of Environment and Climate Change Canada, submit comprehensive annual emissions reports, and undergo independent third-party verification of its emissions data. This reporting threshold applies broadly across the oil and gas sector, which includes monitoring GHG emissions from facilities with significant outputs. Any operators that do not register would be prohibited from emitting GHGs from their industrial activities unless and until registration is completed.

In addition to the emissions-based reporting threshold, any operator producing at or above an annual threshold of 365,000 BOE would be classified as a "Covered Operator". Once classified, operators would be subject to remittance obligations under the emissions cap framework. Every Covered Operator would be required to submit one compliance unit for each tonne of emissions produced. There are three categories of compliance units: (i) emission allowances; (ii) decarbonization units; and (iii) certain GHG offset credits.

The final version of the Proposed Regulations is expected to be published in mid-2025 and come into force by January 1, 2026. The cap-and-trade system as well as the reporting obligations would be phased in over a four-year period from 2026-2029.

### *Alberta*

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the Responsible Energy Development Act and a number of related statutes including the Oil and Gas Conservation Act (the "OGCA"), the Oil Sands Conservation Act, the Pipeline Act, and the Environmental Protection and Enhancement Act. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Land and Property Rights Tribunal, as well as Alberta Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effect management approach into such plans.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, increased seismicity induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate crude oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity is higher, and implemented the requirements in Subsurface Order Nos. 2, 6 and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the Seismic Protocol Regions). Crude oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the crude oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

### *Saskatchewan*

The Saskatchewan Ministry of the Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. The Oil and Gas Conservation Act (the "SKOGCA") is the statute governing the regulation of resource development operations in the province, along with The Oil and Gas Conservation Regulations, 2012 and The Petroleum Registry and Electronic Documents Regulations. The Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as a partner in the Petrinex Database. The Petrinex Database delivers business processes and information required for the assessment, levy, and collection of crown royalties for Alberta, Saskatchewan, Manitoba and British Columbia. It provides information in support of the regulatory mandates and legislation of the provinces, and services that facilitate important industry commercial activities, including partner to partner reporting, oil marketing, financial analytics, compliance assurance and production accounting.

Saskatchewan launched the Inactive Liability Reduction Program ("ILRP") in January of 2023. The ILRP aims to reduce the total number of inactive liabilities for oil and gas companies. In 2023, the program required oil and gas companies to retire 5% of their inactive liabilities such as inactive wells, and facilities in Saskatchewan. This percentage increased to 6% in 2024 and will remain at 6% for 2025.

***British Columbia***

In British Columbia, the Energy Resource Activities Act ("ERAA") (formerly the Oil and Gas Activities Act) impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the ERAA, the British Columbia Energy Regulator (the "BCER") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The Environmental Protection and Management Regulation establish the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The ERAA requires the BCER to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural gas activity. In addition, although not an exclusively environmental statute, the Petroleum and Natural Gas Act, in conjunction with the ERAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licenses, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licenses and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The Government of British Columbia has a regime to monitor and manage the risk of induced seismicity related to crude oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The Drilling and Production Regulation requires a producer to suspend its operations if they trigger a seismic event with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BCER before resuming production. The BCER requires all natural gas producers to conduct ground monitoring and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

British Columbia’s environmental assessment regime subjects proposed projects to an enhanced environmental review process that enhances indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the Environmental Assessment Act, the British Columbia Government enacted the accompanying Reviewable Projects Regulation, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project.

On March 14, 2023, the province of British Columbia announced a new energy action framework (the Action Framework). The Action Framework intends to mandate proposed LNG facilities in or entering the environmental assessment process to pass an emissions test and develop a credible net-zero plan by 2030. It also intends to implement a regulatory emissions cap for the oil and gas industry to meet British Columbia's 2030 emissions reduction target. Further, it establishes a clean-energy and major projects office to expedite investments in clean energy and technology for sustainable job creation. The Action Framework is also intended to create a BC Hydro task force aimed at hastening the electrification of British Columbia's economy through renewable electricity for homes, businesses, and industries. A key measure of the Action Framework is the implementation of a backstop to the federal cap on emissions from the oil and gas sector. Regulatory measures are anticipated to be introduced in 2025 and expected to take effect in 2026.

**Liability Management Rating Programs**

***Alberta***

The AER oversees closure requirements, including the abandonment and reclamation of wells, well sites, facilities, facility sites, and pipelines. Historically, the AER discharged this role through its Liability Management Rating Program (the "AB LMR Program"), which is being replaced in phases by the AER’s Liability Management Framework (the "AB LMF"). The primary goal of the AB LMF is to reduce the number of inactive sites and create a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project.

As a result of the Supreme Court of Canada's decision in *Orphan Well Association* v *Grant Thornton* (also known as the "Redwater" decision), 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 licence transfer when any such licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta pass the Liabilities Management Statutes Amendment Act, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the orphan fund ("Orphan Fund") established under the OGCA to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Complementing the AB LMF program and associated directives, Alberta's OGCA establishes the Orphan Fund to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be funded by licensees in the AB LMR Program who contribute to a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work and has also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund. On March 28, 2024, the AER published Bulletin 2024-08 prescribing an Orphan Fund Levy of $135 million for the 2024/25 fiscal year which will be allocated among licensees and approval holders. Collectively, these programs, the AB LMF, and associated directives are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

Following the Redwater decision, Alberta committed to actively reducing inventories of orphan and inactive well sites in the province. The AB LMF addresses five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) a licensee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the AB LMF; and (v) the Orphan Well Association taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure.

On October 8, 2024, the AER announced an invitation for feedback on revised liability directives, specifically considering the potential rescinding of Directive 006: Licensee Liability Rating Program, Directive 024: Large Facility Liability Management Program and Directive 075: Oilfield Waste Liability Program. Among other changes under the AB LMF, the Licensee Liability Rating Program and security deposit collection for licence transfer have been replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the Licensee Liability Rating Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of oil and natural gas projects. Importantly, the AB LMF provides proactive support to distressed operators and requires companies operating in Alberta's oil and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the AB LMF, each licensee is required to meet mandatory annual spend targets for well closures and abandonments.

Pursuant to the AER’s inventory reduction program implemented under Directive 088: Licensee Life-Cycle Management, licensees are required to meet closure spend requirements aimed at mitigating liabilities associated with inactive and orphan wells. The AER prescribes an industry-wide closure spend requirement each year. A licensee's mandatory closure spend is calculated using a licensee's proportion of industry-wide inactive liability and their level of financial distress determined by the licensee capability assessment. Generally, closure spend rates will be lower for licensees experiencing significant financial distress, and higher for licensees experiencing no financial distress. The industry-wide closure spend requirement for 2024 was set at $700 million, and the 2025 requirement is set at $750 million.

The AB LMF continues to be implemented by the AER with gradual and phasing changes to legislative, regulatory and AER directives required to effectively implement the AB LMF and properly phase-out the AB LMR Program as the AB LMR Program is integrated in several directives and throughout governing legislation.

***Saskatchewan***

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "SK LLR Program"), which was updated in January 2023. The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "Oil and Gas Orphan Fund") established under the SKOGCA. The Oil and Gas Orphan Fund takes on the obligation of carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program also outlines requirements for security deposits and licence transfers. If a licence holder wishes to transfer a licence, a licence transfer application must be completed through the Integrated Resource Information System ("IRIS"). An assessment is conducted on both the transferee and the transferor listed in the IRIS application. To complete the assessment, both a licensee liability rating ("LLR") assessment and a proportional risk transfer is conducted. If a licence transfer will result in either the transferor or transferee having an LLR of less than 1.0, the transferor or transferee, as applicable, must submit the amount of security deposit required by the minister.

In February 2021, the Energy Regulation Division of the Ministry of Energy and Resources announced that it was consulting with stakeholders on proposed regulatory enhancements intended to strengthen Saskatchewan's oil and gas liability management framework and reduce the prospect of new orphan oil and gas wells and facilities in Saskatchewan. This process led to the development of the new Financial Security and Site Closure Regulations (the "Closure Regulations"), which came into force on January 1, 2023.

The Closure Regulations include: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. The Oil and Gas Conservation Regulations, 2012 (the "Conservation Regulations") remain in effect. Among other things, the Conservation Regulations provide a formula for determining a licensee's LLR, outline eligibility requirements for holding licences, and provide guidance on when a security deposit may be required by a licensee or in connection with a transfer.

### *British Columbia*

The BCER has a Comprehensive Liability Management Plan (CLMP) to ensure that 100% of the costs associated with the reclamation of oil and natural gas sites is paid by industry, rather than the Government of British Columbia or residents of British Columbia. Pursuant to the CLMP, the BC Commission is implementing a Permittee Capability Assessment (PCA) program. Similar to the AB LMF, the PCA program is intended to be a holistic evaluation of permittees throughout the development life cycle and is intended to replace the BC LMR Program. The PCA program is intended to mitigate risk and minimize pressure on the Orphan Site Reclamation Fund.

The Orphan Site Reclamation Fund ("OSRF") is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The OGAA permits the BC Commission to impose more than one levy in a given calendar year.

The Dormancy and Shutdown Regulation (the "Dormancy Regulation") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of dormant sites are reclaimed by 2036 with additional regulated timelines for sites that became dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BCER, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in an annual work plan.

## 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. On April 22, 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. When Canada ratified the Paris Agreement, it 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.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. In March 2022, the Government of Canada also introduced Canada's 2030 Emissions Reduction Plan (the "2030 Reduction Plan"), which provides the building blocks for the Canadian economy to achieve 40% to 45% emissions reductions below 2005 levels by 2030. The 2030 Reduction Plan includes $9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress of the 2030 Reduction Plan will be reviewed and produced in reports in 2023, 2025 and 2027, with additional targets to be developed for 2035 and 2050. On September 4, 2024, the federal government published the 2023 Progress Report. The 2023 Progress Report indicated that Canada is expected to exceed the interim objective of a 20% reduction by 2026.

Pursuant to Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050, Canada joined over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. The Canadian Net-Zero Emissions Accountability Act became law in June 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation also sets rolling five-year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrines greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

The federal government established a GHG regime pursuant to the GGPPA, which has two parts: an output-based pricing system for large industry and a regulatory fuel charge (the "Fuel Charge") imposing an initial price of $20/tonne of CO2e emissions. 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 price on emissions across the country. In accordance with the 2030 Reduction Plan, the price on carbon is set to increase annually at a rate of $15/tonne of CO2e per year commencing in 2023 through to 2030. In August 2021, the federal government established strengthened minimum national standards (the federal benchmark) for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. Once in place, the systems will remain until 2027. The minimum carbon pollution price for 2024 is $80/tonne of CO2e, increasing to $95/tonne of CO2e on April 1, 2025.

The constitutionality of the GGPPA was challenged by several provinces, with the SCC ultimately upholding its constitutionality. Any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards. For so long as the provincial systems in Alberta (under the Technology Innovation and Emissions Reduction (TIER) regulation), British Columbia and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

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, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting.

In December 2023, the federal government stated that the existing measures, which were designed to reduce the oil and gas sector's methane emissions by 40–45% by 2025 (relative to 2012) would not be sufficient to meet Canada's commitment to achieving a 75% reduction (below 2012 levels) by 2030. Accordingly, it released proposed amendments which would build on the existing requirements and increase stringency by introducing new prohibitions and limits on certain intentional emissions, a new risk-based approach around unintentional emissions, and a new performance-based approach for compliance that relies on continuous emissions monitoring systems, among other things. The proposed amendments are targeted to come into force in January 2027.

The Clean Fuel Regulations ("CFS Regulations") came into force on June 21, 2022. The CFS Regulations take a performance-based approach to reducing greenhouse gas emissions. The CFS Regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of their liquid fossil fuels. Beginning in 2023, the carbon intensity reduction requirement started at 3.5 g CO2e/MJ, increasing by 1.5 gCO2e/MJ each year and reaching 14 gC02e/MJ in 2030. The standard applies to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada. 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 regulations offer compliance credits to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

On July 24, 2023, the Minister of Environment and Climate change released the Inefficient Fossil Fuel Subsidies Government of Canada Self-Review Assessment Framework and the Inefficient Fossil Fuel Subsidies Government of Canada Guidelines. The documents will support the federal government's focus on clean energy and net-zero initiatives and the de-carbonization of Canada's oil and gas sector. Pursuant to the Framework, subsidies are deemed "inefficient" unless they satisfy certain criteria, which include, but are not limited to: supporting clean energy, clean technology, or renewable energy; providing essential energy service to a remote community; providing short-term support for emergency response; supporting Indigenous economic participation in fossil fuel activities; or supporting abated production processes, such as carbon capture, utilization, and storage, or projects that have a credible plan to achieve net-zero emissions by 2030.

In June 2024, the federal Competition Act was amended to enact new deceptive marketing provisions targeting "greenwashing". The new provisions introduced unclear substantiation requirements for companies making environmental claims and significant fines for failing to meet the new requirements. As a result of the uncertainty with respect to the applicability of the new rules, some companies removed their environmental and sustainability-related disclosure from the public domain. In December 2024, the constitutionality of the new deceptive marketing provisions was challenged in the Alberta Court of King's Bench and the lawsuit remains ongoing.

**Alberta**

In 2019 the Fuel Charge took effect in Alberta. In accordance with the GGPPA, the Fuel Charge payable in Alberta is currently $80/tonne of CO2e and will increase to $95/tonne on April 1, 2025. In December 2019, the federal government approved Alberta's TIER regulation, which applies to large emitters and those who have opted-in. The TIER regulation came into effect on January 1, 2020 and replaced the previous Carbon Competitiveness Incentives Regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. Starting in 2020, most TIER-regulated facilities were required to reduce emission intensity by 10%, with an additional 1% annual reduction thereafter. Recent amendments introduced a 2% annual tightening rate for facility-specific and high-performance benchmarks, replacing the previous facility-specific benchmarks for some facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, while facilities with significant prior reductions can use a high-performance benchmark to account for compliance costs. Facilities emitting 2,000 to 10,000 tonnes of CO2e annually can now opt into the program under amended thresholds. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and, may meet thresholds by either purchasing credits from other facilities, purchasing carbon offsets, or paying 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.

In furtherance of global emissions reductions targets, the Government of Alberta had announced a goal to lower annual methane emissions by 45% by 2025. In November 2023, it was announced that Alberta had achieved its goal of reducing methane emissions by 45%, ahead of schedule.

In May 2020, the federal government and the Government of Alberta announced a preliminary equivalency agreement (the Equivalency Agreement) regarding the reduction of methane emissions. Should amendments to the Federal Methane Regulations come into effect and the Government of Alberta challenges such amendments, the potential effects of such legislation in Alberta, or the effects of any potential challenge to their implementation by the Government of Alberta is unknown.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap, outlining its potential to lead global and national decarbonization. Phase one focuses on policy, technology investments and supply chain commercialization, while phase two aims to scale production and commercialization.

In February 2023, the TIER regulation was amended to, among other things, amend the opt-in thresholds for emissions-intensive and trade-exposed industries, tighten facility-specific benchmarks, revise the credit use limits and expiration periods as well as create sequestration credits for carbon capture, utilization and storage projects. The TIER regulation will be subject to a subsequent review which must be completed by December 31, 2026.

***Saskatchewan***

The Management and Reduction of Greenhouse Gases Act (the "MRGGA") regulates GHG emissions in the province. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. Subsequently, the Government released Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030. The MRGGA, which is partially compliant with the federal emissions trading system, was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full in December 18, 2018, establishing the framework of an output-based emissions management framework. As noted above, the federal fuel charge applies in Saskatchewan and the system implemented by the MRGGA currently meets the federal stringency requirements for the emissions it covers and the federal backstop applies for those emissions which are not covered.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations, the Management and Reduction of Greenhouse Gases (Reporting and General) Regulations, and The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, The Oil and Gas Emissions Management Regulations (the Saskatchewan O&G Emissions Regulations) came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonne CO2e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO2e between 2020 and 2030.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the Province's progress on goals set out under Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

On October 1, 2019, Bill 147 – An Act to amend The Oil and Gas Conservation Act, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented Directive PNG017: Measurement Requirements for Oil and Gas Operations, which came into force in December 2019 and was amended in April 2020, and Directive PNG036: Venting and Flaring Requirements, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In July of 2024, the Government of Saskatchewan and the federal government entered into an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on December 31, 2029.

***British Columbia***

Pursuant to British Columbia’s Climate Leadership Plan, the Government of British Columbia has targeted to reduce British Columbia’s net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050.

The Greenhouse Gas Industrial Reporting and Control Act (the "GGIRCA") sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

Pursuant to British Columbia’s clean energy plan (the CleanBC Plan), the Government of British Columbia has agreed to reduce GHG emissions by 40% by 2030. The CleanBC Plan targets British Columbia's industrial, transportation, construction, and waste sectors with strategies such as: increasing clean energy generation, requiring 15% renewable content in natural gas by 2030, reducing diesel and gasoline carbon intensity by 20%, electrifying oil and gas production, cutting methane emissions by 45%, and incentivizing zero-emission vehicles. The CleanBC Plan outlines pathways, including for the oil and natural gas industry, to achieve emissions targets and build a cleaner economy. The CleanBC Plan was further revised with the "CleanBC Roadmap to 2030", pursuant to which the Government of British Columbia committed to better align with the federal government's minimum national stringency standards for carbon pricing.

As part of the Government of British Columbia's 2023 budget, it was announced that starting April 1, 2023, British Columbia's carbon tax would increase to $65/tonne of CO2e and would increase by $15/tonne each year until it reaches $170/tonne in 2030. As of April 1, 2025, British Columbia's carbon tax will increase to $95/tonne of CO2e. In April 2024, British Columbia's carbon pricing system switched to a new made-in-BC output-based pricing system (the "BC OBPS"). The new BC OBPS replaced the province’s CleanBC Industrial Incentive Program, which had been in use since 2019. The BC OBPS applies to large industrial emitters and prices emissions that exceed specific limits. The BC OBPS is intended to provide flexible options to meet compliance obligations while ensuring emissions reductions for industry continue. Participation under the BC OBPS is mandatory for certain industrial producers under the GGIRCA, that emit above 10,000 tonnes of CO2e per year and excludes certain fuels that will still have reporting requirements under GGIRCA. Similar to the federal system and Alberta's TIER system, there will be a voluntary opt-in option for certain industrial operations in regulated sectors that emit less than 10,000 tonnes of CO2e per year.

On July 6, 2021, the Government of British Columbia released the BC Hydrogen Strategy, which lays out a framework for the province to utilize hydrogen in support of the CleanBC Plan. The Hydrogen Strategy sets out 63 actions to be undertaken over three periods of time: (i) short term (2020-2025); (ii) medium term (2025-2030); and (iii) long term (2030-beyond).

In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia. The equivalency agreement has been renewed and will now expire on December 31, 2029.

**Indigenous Rights**

Opposition by Indigenous people to the Company, its operations, development or exploration, or disagreements between Indigenous communities, or between Indigenous peoples and governments, in the jurisdictions in which Bonterra conducts business may adversely impact its reputation, relationship with host governments, local communities and other Indigenous communities. Other impacts may include diversion of management's time and resources, increased legal, regulatory and other advisory expenses, and the Company's ability to explore, develop and continue to operate projects.

In Canada, Indigenous and/or treaty rights held by Indigenous peoples are protected under the constitution. Impacts to these Indigenous and treaty rights must be considered, in particular in areas where the Company operates on Crown lands. In some cases, there may be outstanding Indigenous and treaty rights claims, which may include land title claims, on lands where Bonterra operates, and such claims, if successful, could have a material adverse impact on the Company's operations or pace of growth.

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

In addition, the Canadian federal government and the British Columbia provincial government have passed legislation which requires such governments to take all necessary measures to implement the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). The means and timelines associated with UNDRIP's implementation by government is ongoing and, in some instances, uncertain: additional processes have been and are expected to continue to 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.

# RISK FACTORS

The following are certain risk factors relating to the business of Bonterra which prospective investors should carefully consider before deciding whether to purchase shares. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business, the business of third parties with whom the Company conducts business and the crude oil and natural gas business generally.

**Exploration, Development and Production Risks**

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Company's existing reserves, and the production from them, will decline over time as the Company produces from such reserves. A future increase in the Company's reserves will depend on both the ability of the Company to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Company will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Company may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards, geological and seismic risks, encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. 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 Risks*" in these Risk Factors. In either event, the Company could incur significant costs.

**Volatility in the Oil and Gas Industry**

Market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC and non-OPEC countries, sanctions against Russia, Iran and Venezuela, slowing growth in China and emerging economies, concerns over public health related events and the impact that it will have on the supply of and demand for oil and gas, market volatility and disruptions in Asia, weakening global relationships, conflict between Ukraine and Russia and in the Middle East, isolationist trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Risk Factors - Political Uncertainty*". These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation, see "*Royalties and Incentives*", "*Regulatory Authorities and Environmental Regulation*" and "*Climate Change Regulation*" in "*Industry Conditions*". In addition, difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the crude oil and natural gas industry in Western Canada have at times led to additional downward price pressure on crude oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, Brent and West Texas Intermediate crude oil has at times created uncertainty and reduced confidence in the petroleum and natural gas industry in Western Canada (see "*Industry Conditions - Transportation Constraints, Pipeline Capacity and Market Access*").

A decline in commodity prices may affect the volume and value of the Company's reserves, especially as certain reserves become uneconomic. In addition, lower commodity prices may reduce the Company's cash flow which could result in a reduced capital expenditure budget. As a result, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis. A prolonged period of adverse market conditions may impede the Company's ability to refinance its credit facilities or arrange alternative financing when the credit facilities become due or if the lending limits under the credit facilities are reduced upon periodic review (see "*Risk Factors – Credit Facility Arrangements*"). Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Company may have difficulty raising additional funds in the future or if it is able to do so, it may be on unfavourable and highly dilutive terms. If these conditions persist, Bonterra's cash flow may not be sufficient to continue to fund operations and to satisfy obligations when due and will require additional equity or debt financing and/or proceeds from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory or at all. Similarly, there can be no assurance that the Company will be able to realize any or sufficient proceeds from asset sales to discharge its obligations.

**Adverse Economic Conditions**

The demand for energy, including crude oil, NGLs and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political development in the U.S., Europe, Asia or elsewhere, there could be a significant adverse effect on global financial markets and commodity prices. In addition, the ongoing military conflicts in the Middle East and Ukraine, hostilities in Taiwan and the occurrence or threat of terrorist attacks in the U.S. or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, may adversely affect the Company by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas, (ii) impairing the Company's supply chain, for example, by limiting the manufacturing of materials or the supply of goods and services used in operations, and (iii) affecting the health of the Company's workforce, rendering employees unable to work or travel. These and other factors disclosed elsewhere herein that affect the supply and demand for crude oil, NGLs and natural gas, and the Company's business and industry, could ultimately have an adverse impact on the Company's financial condition, financial performance, and funds flow.

**Commodity Prices, Markets and Marketing**

The marketability and price of oil and natural gas that may be acquired, discovered or produced by Bonterra is, and will continue to be, affected by numerous factors beyond its control. The Company's ability to market its crude 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 of crude oil by rail. (see "*Industry Conditions – Transportation Constraints, Pipeline Capacity and*

*Market Access*" and "*Risk Factors" - Volatility in the Oil and Gas Industry*"). 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, land tenure, allowable production, the export of crude oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East, Ukraine and Taiwan and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. Any material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of Bonterra's anticipated net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Company's reserves. Bonterra might also elect not to produce from certain wells at lower prices.

Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers, sellers, lessors and lessees have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities. See "*Volatility in the Oil and Gas Industry*".

All of these factors could result in a material decrease in Bonterra's expected net production revenue and a reduction in its future crude oil and natural gas acquisition, exploration, development and production activities. Any substantial and extended decline in or continued low crude oil and natural gas prices would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business and financial condition.

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

**Title to and Right to Produce from Assets**

The Company's actual title to and interest in its properties, and its right to produce and sell the oil and natural gas therefrom, may vary from the Company's records. In addition, there may be valid legal challenges or legislative changes that affect the Company's title to and right to produce from its oil and natural gas properties, which could impair the Company's activities and result in a reduction of the revenue received by the Company.

If a defect exists in the chain of title or in the Company's right to produce, or a legal challenge or legislative change arises, it is possible that the Company may lose all, or a portion of, the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

## Volatility of Market Price of Common Shares

The trading price of securities of crude oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. The volatility may affect the ability of holders to sell the common shares at an advantageous price. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the crude oil and natural gas market. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of commodities has increased due to, in part, the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in crude oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities.

Similarly, the market price of the common shares may be due to Bonterra'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 Bonterra or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements*". 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.

## Regulatory Approvals

In order to conduct its oil and natural gas operations, the Company requires regulatory approvals from various government authorities. There can be no assurance that Bonterra will be able obtain or renew all of the regulatory approvals that may be required to conduct operations that it may wish to undertake or that it will obtain such approvals on terms and conditions acceptable to Bonterra.

## Surface Conditions

The exploration for and development of oil and natural gas reserves depends upon access to areas where operations are to be conducted. Oil and gas industry operations are affected by road bans imposed from time to time during the winter break-up and thaw period in the spring. Road bans are also imposed due to snow, mud and rock slides and periods of high water or wild fires which can restrict access to Bonterra's well sites and production facilities.

Bonterra conducts a portion of its operations in areas accessible only on a seasonal basis. Unless the surface is sufficiently frozen, Bonterra is unable to access its properties, drill or otherwise conduct its operations as planned. In addition, if the surface thaws earlier than expected, Bonterra must cease its operations for the season earlier than planned. Limitations on Bonterra's ability to access properties or conduct its operations as planned could result in a shut down or slowdown of its operations, which may adversely affect its business.

## 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. 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 Bonterra's business, financial condition, results of operations, cash flows and value of its oil and gas reserves.

Bonterra's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on the Company's financial performance and funds from operations.

The cost or availability of oil and gas field equipment may adversely affect Bonterra's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and funds from operations.

**Hydraulic Fracturing**

Concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including water aquifer contamination and 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 of. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial 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 Bonterra's 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 delay, increased operating costs, and third-party or governmental claims. They could also increase Bonterra's 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. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Bonterra is ultimately able to produce from its reserves.

In the event federal, provincial, local, or municipal legal restrictions are adopted in areas where Bonterra is currently conducting, or in the future plans to conduct operations, Bonterra 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, Bonterra's 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 Bonterra is ultimately able to produce from its reserves.

**Disposal of Fluids Used in Operations**

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Company's costs of compliance.

**Legal Proceedings**

Bonterra may from time to time be subject to litigation and regulatory proceedings arising in the normal course of its business. Bonterra cannot determine whether such litigation and regulatory proceedings will, individually or collectively, have a material adverse effect on its business, results or operations and financial condition. To the extent expenses incurred in connection with litigation or any potential regulatory proceeding or action (which may include substantial fees of attorneys and other professional advisors and potential obligations to indemnify officers and directors who may be parties to such actions) are not covered by available insurance, such expenses could adversely affect Bonterra's cash position.

**Third Party Credit Risk**

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

Numerous applications have been filed with regulatory bodies within Canada and the U.S. to build or expand existing pipeline infrastructure to transport crude oil and natural gas to markets. If the projects are not approved it may impact our ability to ship our products to sales markets, which could have a material adverse effect on production levels or on the prices that we receive for our production.

**Operational Dependence**

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

**Access to Capital**

The Company will have to incur substantial capital expenditures in the future in order to carry out its oil and natural gas exploration and development activities. While there are various financing forms available to the Company, including the issuance of new equity or debt, asset sales, joint ventures or other alternatives, the Company's ability to arrange such financings or other satisfactory arrangements in the future may depend in part upon the prevailing capital market conditions, as well as the Company's business performance. These factors could negatively impact the Company in terms of its ability to raise additional capital, as well as increased volatility in oil and gas prices which could affect revenues and cash flows and Company valuations.

**Capital Investment**

The timing and amount of capital expenditures will directly affect the amount of income potentially available for payment of dividends to shareholders. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made. To the extent that external sources of capital, including the issuance of additional common shares, become limited or unavailable, the ability of Bonterra to make necessary capital investments to maintain or expand its oil and gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that Bonterra is required to use cash flow from operations to finance capital expenditures, property acquisitions or asset acquisitions, as the case may be, the level of dividends will be reduced.

**General Economic Conditions, Business Environment**

The business of the Company is subject to general economic conditions. Adverse changes in general economic and market conditions could negatively impact demand for crude oil and natural gas, revenues, operating costs, access to capital, timing and extent of capital expenditures, credit risk and counter party risk. There can be no assurance that any risk management steps taken by the Company, with the objective of mitigating the foregoing risks, will avoid future loss due to the occurrence of such risks.

**Issuance of Debt**

From time to time, the Company may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

**Credit Facility Arrangements**

Bonterra has secured credit facilities. Variations in interest rates and scheduled principal repayments, if required under the terms of the credit agreements, could result in significant changes in the amount of working capital required to be applied to debt service. Although it is believed that the bank lines of credit are sufficient there can be no assurance that the amount will be adequate for the financial obligations of Bonterra or that additional funds can be obtained.

In addition, the maximum amount we are permitted to borrow is subject to periodic review by the lenders, typically semi-annually. The Company's lenders generally review the Company's oil and gas production and reserves, forecast prices, business environment and other factors to establish the amount we can borrow. In the event the lenders decide to reduce the amount of credit available, the Company may be required to repay all or a portion of the amounts owing.

**Senior Secured Second Lien Notes**

Bonterra may be required to repay or refinance the remaining principal balances on the Senior Secured Notes with lump-sum payments at or prior to the Senior Secured Notes' maturity date on January 28, 2030. The amounts to be repaid or refinanced at the date of redemption could be significant. The Company may not have sufficient liquidity to make such payments at the Senior Secured Notes' maturity date. In the event the Company does not have sufficient liquidity to completely repay the remaining principal balances at maturity, it may not be able to refinance the Senior Unsecured Notes at interest rates that are acceptable to the Company or, depending on market conditions, refinance the Senior Secured Notes at all. The Company's inability to repay or refinance the Senior Secured Notes could have a material adverse effect on the Company's business, financial condition and results of operations.

Similarly, the Company may not be able to satisfy its debt obligations upon the occurrence of a change of control. Upon the occurrence of a change of control (as defined in the indenture governing the Senior Secured Notes), holders of the Senior Secured Notes will have the right to require the Company to purchase all or any part of such holders' notes at a price of at least 101%

of the principal amount thereof, plus accrued and unpaid interest, if any. The events that constitute a change of control under the Indenture governing the Senior Secured Notes may also constitute a default under the Credit Agreement. The agreements or instruments governing any future debt that the Company may incur may contain similar provisions regarding repurchases in the event of a change of control triggering event. There can be no assurance that the Company would have sufficient resources available to satisfy all of its obligations under these debt instruments in the event of a change of control. In the event the Company were unable to satisfy these obligations, it could have a material adverse impact on its business and shareholders.

**Risks Relating to Credit Ratings**

Rating agencies regularly evaluate the Company and base their ratings of the Company's long-term and short-term debt on a number of factors. The credit ratings applied to the Company and its securities are an assessment by the relevant ratings agencies of the Company's ability to pay its obligations as of the respective dates the ratings are assigned. The credit ratings may not reflect the potential impact of risks related to structure, market or other factors discussed herein on the value of the Company's securities.

Credit ratings affect the Company's financing costs, liquidity and operations over the long term and are intended as an independent measure of the credit quality of long-term debt securities or the issuer. Credit ratings affect the Company's ability to obtain short and long-term financing and its ability to engage in certain business activities in a cost-effective manner. There is no assurance that one or more of our credit ratings will not be downgraded or withdrawn entirely. In addition, real or anticipated changes in credit ratings can affect the cost at which we can access public or private debt markets and may affect the value of the Company's Senior Secured Notes.

**Variations in Foreign Exchange Rates and Interest Rates**

Operating costs incurred by Bonterra are generally paid in Canadian dollars. World crude oil and natural gas prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which fluctuates over time. Material increases in the value of the Canadian dollar negatively impact Bonterra’s production revenues. Future Canadian/U.S. exchange rates could accordingly impact the future value of Bonterra’s reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the U.S. dollar may positively impact the price the Company receives for crude oil and natural gas production it could also result in an increase in the price of certain goods used in operations which may have a negative impact on the Company's financial results.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which Bonterra may contract.

An increase in interest rates could result in a significant increase in the amount Bonterra pays to service debt, which could negatively impact the market price of the common shares.

**Delay in Cash Payments**

In addition to the usual delays in payment by the purchasers of oil and natural gas to the operators of Bonterra's properties, and by the operator to Bonterra, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blow-outs or other accidents, recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for such expenses.

**Reserves Estimates**

Although Sproule has prepared Bonterra's reserve figures using methods of estimating reserves consistent with those commonly followed in the industry and believe that those methods have been verified by operating experience, such figures are estimates and no assurance can be given that the indicated levels of reserves will be produced. Probable reserves estimated for properties may require revisions based on the actual development strategies employed to prove such reserves. Estimated reserves may also be affected by changes in oil and natural gas prices. Declines in the reserves of Bonterra which are not offset by the acquisition or development of additional reserves may reduce the underlying value of the common shares to shareholders.

The reserve report under the heading "*Statement of Reserves Data and Other Oil and Gas Information – Part II - Disclosure of Reserve Data*" has been prepared using certain commodity price assumptions which are described in the notes to the reserve tables. If lower prices for crude oil, NGLs and natural gas are realized by Bonterra and substituted for the price assumptions utilized in the reserve report, the present value of estimated future net cash flows for Bonterra's reserves would be reduced and the reduction could be significant.

**Expiration of Licenses and Leases**

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

**Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

The Company considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and the resources required to provide such services. In this regard, non-core assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company may realize less on disposition than their carrying value on the financial statements of the Company.

**Hedging**

From time to time, Bonterra may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; similarly, the Company may enter into agreements to fix the differential or discount pricing gap which exists, and may fluctuate between different grades of crude oil, NGL and natural gas and the various market prices received for such products. However, if commodity prices or differentials increase beyond the levels set in such agreements, Bonterra may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. In addition, if the Company enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes or prices fall significantly lower than projected; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or a sudden unexpected material event impacts crude oil and natural gas prices.

Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to U.S. dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Company will not benefit from the fluctuating exchange rate.

**Environmental Regulation**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "Industry Conditions – Regulatory Authorities and Environmental Regulation".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge.

In November 2024, the federal government published a draft of the proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations, which, if enacted as currently drafted, would cap emissions from a range of industrial activities in the oil and gas sector, establish a cap-and-trade system for emissions allowances, and require facility operators to comply with various reporting and remittance obligations. Such proposed regulations, which could affect investor confidence, suppress spending on decarbonization initiatives and lead to production cuts, are expected to be finalized in mid-2025 and come into force by January 1, 2026.

Although Bonterra believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

**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 a number of sources including guidelines from provincial regulatory groups, 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.

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 Bonterra, to fund the abandonment and reclamation of these orphan wells.

**Carbon Pricing Risk**

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system, which was upheld by the SCC as constitutional, currently applies in provinces and territories without their own system that meets federal standards and provinces with their own system are subject to continued compliance with the federal system. There is no guarantee that a province with a system that currently applies will meet, or continue to meet federal stringency standards. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

**Political Uncertainty**

The Company's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact the Company's existing operations and planned projects. This includes actions by regulators or other political factors to delay or deny necessary licenses and permits for the Company's activities or restrict the operation of third-party infrastructure that Bonterra relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Company's results.

In early February 2025, the United States announced a 25% broad-based tariff on goods exported out of Canada into the United States, other than energy products (including oil and natural gas), which would be subject to a 10% tariff. In response, the Canadian government announced that it would impose a 25% tariff on $155 billion of goods imported from the U.S. The U.S. also announced a 25% tariff on goods imported from Mexico and a 10% tariff on goods imported from China. Representatives of the U.S. government have also publicly stated that they are considering imposing tariffs on goods imported from other countries. On March 4, 2025, the U.S. tariffs on Canadian and Mexican goods became effective and the U.S. tariff on goods imported from China was increase to 20%. The Government of Canada also announced that its counter-tariffs on goods imported from the U.S. would become effective in two phases commencing on March 4, 2025. On March 6, 2025, the U.S. agreed to exempt from tariffs imports of Canadian goods subject to the USMCA until April 2, 2025. If enacted, these tariffs, and any changes to these tariffs or imposition of any new tariffs, taxes or import or export restrictions or prohibitions, could have a material adverse effect on the Canadian economy, the Canadian oil and natural gas industry and the Company. Furthermore, there is a risk that the tariffs imposed by the U.S. on other countries will trigger a broader global trade war which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company.

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 for Bonterra's products. See *"Industry Conditions – Climate Change Regulation", "Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access" and "Industry Conditions – International Trade Agreements"*.

**Climate Change Regulations**

The Company's exploration and production facilities and other operations and activities emit greenhouse gases ("GHG") which may require the Company to comply with greenhouse gas emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place.

As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the implementation of a nation-wide price on carbon emissions. The federal carbon levy came into effect on April 1, 2019 and affects provinces which have not implemented their own carbon taxes, cap-and-trade systems or other plans for carbon pricing.

The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or could interfere with Bonterra’s operations, increasing costs and negatively impacting production. Over the last several years, certain areas of British Columbia, Alberta and Saskatchewan have been negatively impacted by wildfires causing temporary interruption to both pipeline systems and railway lines. Extreme weather conditions may lead to disruptions in the ability to transport produced oil and natural gas as well as goods and services along supply chains. Certain of Bonterra’s properties are located in regions that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Company is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting operations.

**Royalty Regimes**

There can be no assurance that the governments in the jurisdictions in which the Company has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of the Company's properties. An increase in royalties would reduce the Company’s earnings and cash flow and could make future capital investments or the Company’s operations uneconomic.

**Reliance on Key Personnel**

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

**Human Resources**

The operations and management of the Company require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Company's business plans. The Company competes with other companies in the oil and natural gas industry, as well as other industries, for this skilled workforce. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. In addition, certain of the Company's current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Company is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Company could be negatively impacted. In addition, the Company could experience increased costs to retain and recruit these professionals.

**Management of Growth**

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

**Liability Management**

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER continues to implement its AB LMF, with changes to be gradually phased in over time, replacing the AB LMR Program. The implementation of the AB LMF program or other changes to the requirements of liability management programs may result in significant increases to the Company’s compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the petroleum and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the liability management regime may prevent or interfere with the Company’s ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*".

**Information Technology Systems and Cyber-security**

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

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company’s information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to the Company’s business activities or its competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Company maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. The Company also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Company's efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage its information technology infrastructure. The Company applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company’s performance and earnings, as well as on its reputation, and any damages sustained may not be adequately covered by the Company's current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Company’s business, financial condition and results of operations.

**Reputational Risk Associated with the Company's Operations**

The Company's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Company or as a result of any negative sentiment toward, or in respect of the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Company's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Company has no control. In particular, the Company's reputation could be impacted by negative publicity related to environmental damage, loss of life, injury or damage to property caused by the Company's operations, or due to opposition from special interest groups opposed to oil and natural gas development. In addition, if the Company develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities.

**Changing Investor Sentiment**

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

**Evolving Corporate Governance and Reporting Framework**

The Company’s business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Company’s securities. Bonterra is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities Administrators, the TSX and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Company’s efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

**Dilution**

The Board may issue an unlimited number of common shares without any vote or action by the shareholders, subject to the rules of any stock exchange on which the Company's securities may be listed from time to time. The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities. If the Company issues any additional equity, the percentage ownership of existing shareholders will be reduced and diluted and the price of the common shares could decline.

**Depletion of Reserves**

Bonterra has certain unique attributes which may differentiate it from other oil and gas industry participants. Bonterra will not be reinvesting cash flow in the same manner as other industry participants. Bonterra has a long reserve life index and its decline rate is lower than many other industry participants. Bonterra will be retaining a portion of its cash flow for reinvestment purposes, but the retained amount may be less than other industry participants and could result in decreases in production levels and reserves.

The future oil and natural gas reserves and production of Bonterra, and therefore its cash flows, will be highly dependent on its success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, Bonterra's reserves and production will decline over time as reserves are exploited.

There can be no assurance that Bonterra will be successful in developing or acquiring additional reserves on terms that meet Bonterra's investment objectives.

**Competition**

There is strong competition relating to all aspects of the oil and natural gas industry. Bonterra will actively compete for capital, skilled personnel, undeveloped lands, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Bonterra. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

**Indigenous Claims**

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. The Company is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Company's business and financial results.

**Breach of Confidentiality**

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

**Net Asset Value**

The net asset value of Bonterra’s assets from time to time will vary dependent upon a number of factors beyond the control of management, including oil, natural gas and NGL prices. The trading price of Bonterra’s common shares from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be less than the net asset value of Bonterra’s assets.

### Potential Conflicts of Interest

There may be circumstances in which the interests of entities managed by Bonterra will conflict with those of Bonterra and its shareholders. Companies managed by Bonterra may acquire oil and natural gas properties or entities on their behalf and Bonterra may manage and administer those additional properties or entities, as well as enter into other types of energy related management, advisory and investment activities.

In the event of such conflicts, decisions will be made on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties consistent with the duties of Bonterra to each group of persons. Bonterra will use all reasonable efforts to resolve such conflicts of interest in a manner which will treat Bonterra and other interested parties fairly taking into account all of the circumstances of Bonterra and such interested party and to act honestly and in good faith in resolving such matters.

Circumstances may also arise where members of the Board of Directors of Bonterra are directors or officers of corporations or other entities involved in the oil and natural gas industry which are in competition with the interests of Bonterra. No assurances can be given that opportunities identified by such board members will be provided to Bonterra.

### Management Estimates and Assumptions

In preparing consolidated financial statements estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and the Company must exercise significant judgment. Estimates may be used in management’s assessment of items such as depreciation and accretion, fair values, useful life of assets, income taxes, stock-based compensation and asset retirement obligations. Actual results for all estimates could differ materially from the estimates and assumptions used by the Company, which could have a material adverse effect on the financial condition, results of operations and cash flows of the Company.

### Insurance Risks

The Company’s property and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these or other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis, that all events that could give rise to a loss or liability are insurable, or that the amounts of insurance (net of applicable deductibles) will at all times be sufficient to cover each and every loss or claim that may occur involving the assets or operations of the Company.

### Natural Disasters, Terrorist Acts, Civil Unrest, Pandemics and Other Disruptions and Dislocations

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, state or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on us, our customers, and our business and operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses, domestic and global trade disruptions, infrastructure disruptions, civil disobedience or unrest, natural disasters, national emergencies, acts of war, technological attacks and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could result in a significant reduction in economic activity in Canada and internationally along with a drop in demand for oil and natural gas, as well as affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to us, our customers, and our business and operations, which may have a material adverse effect on our reputation, business, financial conditions or operations and could aggravate the other risk factors identified herein.

**Global Financial Markets**

The market events and conditions that transpired in recent years, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have, among other things, caused significant volatility in commodity prices. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors negatively impacted enterprise valuations and impacted the performance of the global economy. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties regarding the supply and demand fundamentals for petroleum products due to the current state of the world's economies, actions taken by the Organization of the Petroleum Exporting Countries, the ongoing risks facing the North American and global economies and increased supplies of crude oil which may be created by the application of new drilling technology to unconventional resource plays.

**Changes in Legislation and Canadian Tax Considerations**

There can be no assurances that income tax laws and government incentive programs relating to the oil and natural gas industry will not be changed in a manner which adversely affects Bonterra and its shareholders. There can be no assurance that the Canada Revenue Agency will agree with how Bonterra calculates its income for tax purposes or that the Canada Revenue Agency will not change its administrative practices to the detriment of Bonterra or its shareholders.

As Bonterra is engaged in the oil and natural gas business its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation relating to characterization of costs incurred in their businesses which effects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. Bonterra has reviewed its historical income tax returns with respect to the characterization of the costs incurred in the oil and natural gas business as well as other matters generally applicable to all corporations including the ability to offset future income against prior year losses. Bonterra has filed or will file all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation, but such returns are subject to reassessment. In the event of a successful reassessment it may be subject to a higher than expected past or future income tax liability as well as potentially interest and penalties and such amount could be material.

**Internal Controls Over Financial Reporting**

Internal control over financial reporting (“ICFR”), as defined in National Instrument 52-109 (NI 52-109), includes those policies and procedures that:

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of Bonterra;
2. Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Bonterra are being made in accordance with authorizations of management and Directors of Bonterra; and

3. Are designed to provide reasonable assurance regarding prevention or timely detection of authorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

The Company has designed and implemented ICFR as defined in NI 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework the Company used to design its ICFR was in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013).

It should be noted that while the Company's believes its internal controls and procedures provide a reasonable level of assurance and are effective; they do not expect that these controls will prevent all errors and fraud.

**Cost of New Technologies**

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

**Availability of Equipment and Qualified Personnel and Related Costs**

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment and qualified personnel in the particular areas where such activities will be conducted. Demand for such limited equipment and qualified personnel may affect the availability of such equipment and qualified personnel to Bonterra and may delay Bonterra's exploration and development activities. In addition, the costs of qualified personnel and equipment in the areas where Bonterra's assets are located are very high due to the availability of, and demands for, such qualified personnel and equipment in such areas.

**Project Risks**

The Company manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the following: processing capacity availability; availability and proximity of pipeline capacity; availability of storage capacity; availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods; the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations; effects of inclement weather; availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; regulatory changes; availability and productivity of skilled labour; and regulation of the oil and natural gas industry by various levels of government and governmental agencies. These factors could result in Bonterra being unable to execute projects on time, on budget, or at all and may be unable to effectively market its oil and natural gas products.

**Gathering and Processing Facilities, Pipeline Systems and Rail**

The products that Bonterra produces must be delivered through gathering, processing and pipeline systems, some of which are not owned by the Company, and in certain circumstances, by rail. The amount of crude oil and natural gas produced and sold from Bonterra's assets is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect production and operations which may have a material adverse effect on the Company's business and financial condition.

A portion of Bonterra's production is processed through facilities owned by third parties over which the Company has no 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 discontinuation or decrease of third party facility operations could have a materially adverse effect on Bonterra's production and ability to deliver the same for sale, which, in turn, would indirectly reduce the Company's revenues. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

**Seasonality and Climate**

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may result in limited access and, as a result, reduced operations or a cessation of operations.

Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of Bonterra.

**Alternatives to, and Changing Demand for, Petroleum Products**

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

**Waterflood**

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

In April 2024, in the face of severe drought risks following several warm, dry winters causing Alberta's snowpack, rivers and reservoirs to be low, Alberta entered into water-sharing agreements with 38 of the largest and oldest water licensees in southern Alberta, including in the Red Deer River, Bow River and Old Man River basins. In the event of a drought, such agreements aim to mitigate the negative effects of such drought by providing increased access to water. Notwithstanding such agreements, any reduced availability of water could have a material adverse effect on results of our operations and our financial condition.

**Anti-Greenwashing Rules**

On June 20, 2024, Bill C-59 received royal assent, thereby enacting certain changes to the Competition Act to address "greenwashing", meaning false, misleading, or deceptive environmental claims made for the purpose of promoting a product or a business interest. Under the new rules, certain environmental claims that companies commonly make, including those related to sustainability and forward-looking environmental-related goals, may be problematic. How the new rules will be interpreted and applied is currently unclear. In June 2025, new private rights of action will come into effect, meaning that any person will be able to bring a complaint directly to the Competition Tribunal for an alleged violation of the new greenwashing provisions. The Competition Bureau has published draft guidance regarding how it will apply the new greenwashing provisions, however the guidance, even once finalized, is not and will not be binding on private parties nor the Competition Tribunal. Companies found to have made representations that violate the rules, intentionally or inadvertently, could be subject to an administrative penalty for the greater of $10 million for the first order and $15 million for any subsequent order, and 3% of the company's annual worldwide gross revenues.

**Limited Ability of Residents in the United States to Enforce Civil Remedies**

The Company is a corporation formed pursuant to the provisions of the Canada Business Corporations Act and has its principal place of business in Alberta, Canada. All of our directors and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against the Company or against any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

**Forward-Looking Information May Prove Inaccurate**

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

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

# MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The financial statements and the management's discussion and analysis of its financial condition and results of operations for the year ended December 31, 2024, as contained in the Company's Annual Report for the year ended December 31, 2024 is incorporated by reference in this Annual Information Form.

# DIVIDENDS TO SHAREHOLDERS

**Cash Dividend Policy**

Shareholders of record on a dividend record date are entitled to receive dividends which are paid by Bonterra to its shareholders on the corresponding dividend payment date. Bonterra has established that the dividend record date will be on or about the 15th day of each calendar month with the last day of each month being the corresponding payable date.

On March 10, 2020, the Company's Board of Directors elected to suspend its monthly dividend, commencing on April 1, 2020. The following cash dividends were paid by Bonterra since 2020:

| Month of Record and Payment Date | Amount per Share |
|---|---|
| January 2020 | $0.01 |
| February 2020 | $0.01 |
| March 2020 | $0.01 |

**The historical dividend payments described above may not be reflective of future dividend payments, which will be subject to review by the Board of Directors taking into account the prevailing financial circumstances of Bonterra at the relevant time. See "Risk Factors".**

# CAPITAL STRUCTURE

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

Transactions during the years 2024 and 2023 in the shares of the common stock of the Company are as follows:

| | **December 31, 2024** | | December 31, 2023 | |
|---|---|---|---|---|
| Issued and fully paid – common shares | **Number** | **Amount ($ 000s)** | Number | Amount ($ 000s) |
| Balance, beginning of year | **37,253,252** | **783,185** | 36,912,892 | 781,679 |
| Issued pursuant to the Company's share option plan | **71,628** | **50** | 340,360 | 596 |
| Transfer from contributed surplus to share capital | | **130** | | 910 |
| Balance, end of year | **37,324,880** | **783,365** | 37,253,252 | 783,185 |

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

The Company provides an equity settled stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 3,732,488 (December 31, 2023 – 3,725,325 common shares). The exercise price of each option granted will not be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock option plan as of December 31, 2024 and December 31, 2023, and changes during the years ended on those dates is presented below:

| | **Number of options** | **Weighted average exercise price** |
|---|---|---|
| At January 1, 2023 | 2,751,750 | $6.86 |
| Options granted | 1,171,000 | 5.47 |
| Options exercised | (446,750) | 2.92 |
| Options forfeited | (171,000) | 7.81 |
| Options expired | (45,000) | 5.18 |
| At December 31, 2023 | 3,260,000 | $6.87 |
| Options granted | 147,000 | 4.81 |
| Options exercised[(1)] | (118,500) | 2.67 |
| Options forfeited | (145,500) | 7.21 |
| Options expired | (37,500) | 8.13 |
| At December 31, 2024 | 3,105,500 | $6.90 |

(1) 108,500 options (December 31, 2023 - 247,000) were exercised under the cashless option method, which resulted in 61,628 (December 31, 2023 – 140,610) shares being issued in which the Company received no proceeds. Under the cashless option method, the remaining options between the number of options exercised and shares issued are cancelled.

The following table summarizes information about options outstanding at December 31, 2024:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of exercise prices | Number outstanding | Weighted-average remaining contractual life | Weighted-average exercise price | Number exercisable | Weighted-average exercise price |
| $ 1.00 - $ 5.00 | 165,000 | 3.0 years | $ 4.37 | 65,000 | $ 4.35 |
| 5.01 - 10.00 | 2,910,500 | 3.1 years | 6.99 | 1,531,955 | 7.39 |
| 10.01 - 15.00 | 30,000 | 0.9 years | 12.32 | 15,000 | 12.32 |
| $ 1.00 - $ 15.00 | 3,105,500 | 3.0 years | $ 6.90 | 1,611,955 | $ 7.31 |

# MARKET FOR SECURITIES

The outstanding shares are listed and posted for trading on the Toronto Stock Exchange (TSX) under the trading symbol BNE. The following table sets forth the high and low trading prices and the aggregate volume of trading of the shares and trust units as reported by the TSX for the periods indicated.

| Month | Price Range | Volume |
|---|---|---|
| January 2024 | $4.61 - $5.46 | 893,290 |
| February 2024 | $4.36 - $5.10 | 993,315 |
| March 2024 | $5.08 - $6.43 | 1,326,619 |
| April 2024 | $5.71 - $6.87 | 1,844,231 |
| May 2024 | $5.14 - $5.93 | 1,133,113 |
| June 2024 | $4.67 - $5.39 | 906,544 |
| July 2024 | $4.57 - $5.35 | 1,039,383 |
| August 2024 | $4.32 - $4.90 | 1,088,974 |
| September 2024 | $3.50 - $4.39 | 1,091,188 |
| October 2024 | $3.34 - $4.02 | 965,408 |
| November 2024 | $3.10 - $3.67 | 1,181,747 |
| December 2024 | $3.10 - $3.80 | 1,266,548 |

On December 31, 2024, the closing price of Bonterra shares on the TSX was $3.77 (December 31, 2023 - $5.23).

# ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of the directors and executive officers of Bonterra, none of the securities of Bonterra are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

# DIRECTORS AND OFFICERS

All directors of Bonterra are elected by its shareholders at each annual meeting of shareholders. All directors serve until the next annual meeting or until a successor is elected or appointed. All officers are appointed by the Board of Directors. The name, municipality of residence, principal occupation for the past five years and year of appointment as a director or commencement of employment for officers of Bonterra are set forth as follows:

| Name and Municipality of Residence | Position Since | Principal Occupation for Past Five Years |
|---|---|---|
| John J. Campbell, ICD.D (1)(3)(4)<br>Calgary, AB | Director<br>May, 2020 | An independent director and consultant that has over 25 years of experience in private equity, energy services, banking and trust company services. Mr. Campbell also currently serves as Chair of Morcado Trust Company and Audit Committee Chair of Haw Capital 2 Corp. Mr. Campbell is also the former President and Co-Founder of Odyssey Trust Company. Holder of the Institute of Corporate Directors' Director designation. |

| | | |
|---|---|---|
| Brad A. Curtis<br>Calgary, AB | Senior Vice President, Business Development<br>March, 2017 | B. Com., B.Sc., P.Geo, Mr. Curtis has been Vice President, Business Development since February 2012 and has held various positions with Bonterra since 2005. |
| David M. Humphreys, ICD.D(2)(3)(4)<br>Calgary, AB | Director<br>August, 2023 | An independent director and retired Executive Vice President, Operations with 40 years of Canadian energy industry experience. Mr. Humphreys holds a designation with the Institute of Corporate Directors and the Association of Professional Engineers and Geoscientists of Alberta (“APEGA”). |
| Scott A. Johnston<br>Calgary, AB | Chief Financial Officer & Corporate Secretary<br>September, 2024 | Mr. Johnston most recently served as a partner at a highly regarded investment bank and brings over 18 years of finance, capital markets and engineering experience. |
| Stacey E. McDonald, ICD.D(1)(2)(4)<br>Calgary, AB | Director<br>August, 2021 | Ms. McDonald is a director of Birchcliff Energy Ltd. and has over 15 years of experience in the energy and financial sectors. From September 2016 to July 2018, Ms. McDonald was a Managing Director – Institutional Equity Research (Energy) at GMP FirstEnergy and its predecessor, GMP Securities, independent global investment banks. Holder of the Institute of Corporate Directors’ Director designation. |
| Patrick G. Oliver(2)<br>Calgary, AB | President, Chief Executive Officer & Director<br>September, 2022 | B.Com., C.A., Mr. Oliver has over 35 years of E&P experience in various executive roles in both the public and private sector. Over the past 20 years, the majority as CEO, Mr Oliver was instrumental in the building and successful sale of four privately owned Birchill companies with operations in central Alberta. Mr Oliver is also a Director of Enercapita Energy Ltd., a private oil and gas company. |
| Jacqueline R. Ricci(1)(3)(4)<br>Toronto, ON | Director<br>May, 2020 | Ms. Ricci is Vice President and Partner at J Zechner Associates, managing discretionary funds focused on small/mid-cap equities including and oil and gas. She has |

| | | |
|---|---|---|
| | | held senior investment analyst roles at Ontario Teachers' Pension Plan Board and Gluskin Sheff & Associates. She serves on the boards of Wesdome Gold Mines Ltd. and Pine Cliff Energy Ltd., chairing the latter's Governance, Nominations, and Compensation Committee. A recipient of multiple TopGun Investment Mind Awards, she holds an HBA from the University of Western Ontario and is a holder of a CFA designation. |
| D. Michael G. Stewart(1)(2)(3)(4)<br>Calgary, AB | Chair and Director<br>March, 2021 | B.Sc., P.Eng. (non-practicing), Corporate Director, with almost 50 years of experience in the Canadian energy industry and an extensive track record serving as a senior executive and on boards of directors and audit committees. |

Notes:
(1) Member of the Audit Committee. Chaired by Stacey E. McDonald.
(2) Member of the Reserve Committee. Chaired by David M. Humphreys.
(3) Member of the Human Resources and Compensation Committee. Chaired by John J. Campbell
(4) Member of the Governance and Nominating Committee. Chaired by Jacqueline R. Ricci

Directors and officers of Bonterra as a group beneficially owned, controlled, directly or indirectly, 491,471 common shares representing approximately 1.3 percent of the issued and outstanding common shares of Bonterra as at March 13, 2025 the date of this report.

**Cease Trade Orders**

To the best of Bonterra's knowledge, no director or executive officer is, or within the ten years prior to the date hereof has been, a director, chief executive officer or chief financial officer of any company (including the Company) that: (i) while that person was acting in that capacity, was subject to a cease trade or similar order or an order that denied such company access to any exemptions under securities legislation, that was in effect for a period of more than 30 consecutive days; or (ii) was subject to a cease trade or similar order or an order that denied such company access to any exemptions under securities legislation, that was in effect for a period of more than 30 consecutive days that was issued after that person ceased to act in such capacity and which resulted from an event that occurred while that person was acting in such capacity.

**Bankruptcies**

To the best of Bonterra's knowledge, no director or executive officer of the Company, or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (i) is, as at the date of this Annual Information Form, or has been within the past 10 years, a director or executive officer of any company (including the Company) that while the person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the past ten years before the date of this Annual Information Form become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

### Penalties or Sanctions

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

# AUDIT COMMITTEE INFORMATION

The following information is provided in accordance with Form 52-110F1 under the Canadian Securities Administrators' National Instrument 52-110 - Audit Committees (NI 52-110).

**Audit Committee Charter**

The Audit Committee Charter is attached as Appendix "C" to this Annual Information Form.

**Composition of the Audit Committee**

The Audit Committee is comprised of Michael G. Stewart, Stacey E. McDonald and Jacqueline R. Ricci. Each director is considered "independent" and "financially literate" (as such terms are defined in NI 52-110).

**Relevant Education and Experience**

Collectively, the Audit Committee has the education and experience to fulfill the responsibilities outlined in the Audit Committee Charter. The education and current and past experience of each Audit Committee member that is relevant to the performance of his responsibilities as an Audit Committee member is summarized as follows:

| **Name** | **Education and Experience** |
|---|---|
| John J. Campbell | • An independent director and consultant that has over 25 years of experience in private equity, energy services, banking and trust company services. Mr. Campbell is also the Board Chair of Morcado Trust and Audit Committee Chair of Haw Capital 2 Corp.<br>• Prior experience includes President and Co-Founder of Odyssey Trust, General Manager of Valiant Trust, Oil & Gas commercial lending with Canadian Western Bank. He was also the former Chair of the Audit Committee of Haw Capital Corp and Golo Mobile Inc.<br>• Bachelor of Commerce, Finance and ICD.D. |
| Stacey E. McDonald (Chair) | • Strategic and Financial Advisory services. Bachelor of Commerce Degree with ICD.D designation.<br>• Ms. McDonald is an independent consultant and has over 15 years of experience in the energy and financial sectors From September 2016 to July 2018, Ms. McDonald was a Managing Director – Institutional Equity Research (Energy) at GMP FirstEnergy and its predecessor, GMP Securities, independent global investment banks. |
| Jacqueline R. Ricci | • Vice President and Director at J. Zechner Associates since 1997.<br>• CFA with more than 35 years of experience in evaluating business plans and management performance in small and mid capitalization companies in the Canadian market.<br>• Member of the audit committee for both Pine Cliff Energy Ltd. and Wesdome Gold Mines Ltd. |
| D. Michael G. Stewart | • Corporate director with more than 50 years of experience in the Canadian energy industry and an extensive track record serving as a senior executive and on boards of directors and audit committees. |

**Pre-Approval Policies and Procedures**

The Audit Committee is authorized by the Board of Directors to review the performance of the Company's external auditors, and approve in advance provision of services other than auditing and to consider the independence of the external auditors, including reviewing the range of services provided in the context of all consulting services engaged by Bonterra. The Audit Committee is authorized to approve any non-audit services or additional work which the Chairman of the Audit Committee deems as necessary who will notify the other members of the Audit Committee of such non-audit or additional work. The audit committee has specified that management may authorize non-audit services to a maximum amount of $20,000 per project without prior audit committee approval.

**External Auditor Service Fees (By Category)**

The fees for auditor services billed by the Company's external auditors in each of the last two fiscal years ending December 31, are as follows:

| Year | Audit | Audit Related Fees | Tax Fees | All Other Fees |
|---|---|---|---|---|
| 2023 | $177,000 | $87,000 | $ - | $ - |
| 2024 | $205,000 | $81,000 | $ - | $ - |

### REGULATORY ACTIONS

To the knowledge of Bonterra, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the Company's most recently completed financial year; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

### INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as set out herein, management is not aware of any material interests, direct or indirect, of any directors or executive officers of Bonterra, any person or company which beneficially owns or controls or directs, directly or indirectly, more than ten percent of the outstanding common shares of the Company, or any known associate or affiliate of such persons, in any transaction within the last three financial years of the Company, or during the current financial year which has materially affected or is reasonably expected to materially affect the Company.

## INTERESTS OF EXPERTS

Sproule Associates Limited prepared the Sproule Report.

The Company has been advised by Sproule Associates Limited that as of the date hereof, the directors, officers and associates as a group, do not beneficially own, directly or indirectly, any common shares of Bonterra.

The independent auditor of the corporation is Deloitte LLP ("Deloitte"), Independent Registered Chartered Accountants, Calgary, Canada. Deloitte has confirmed that it is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

# MATERIAL CONTRACTS

During the year ended December 31, 2024, Bonterra has not entered into any contracts, nor are there any contracts still in effect, that are material to the business, other than contracts entered into the ordinary course of business.

# ADDITIONAL INFORMATION

Additional information relating to Bonterra may be found on SEDAR at www.sedar.com. Information including directors' and officers' remuneration, principal holders of Bonterra's securities, and options to purchase securities is contained in Bonterra's Information Circular dated April 1, 2024. Additional financial information is contained in Bonterra's comparative financial statements and management's discussion and analysis of financial conditions and results of operations for the years ended December 31, 2024 and 2023, which are included in Bonterra's Annual Report for the year ended December 31, 2024.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraph please visit our website at www.bonterraenergy.com or contact:

> Bonterra Energy Corp.
> 901, 1015 4th Street S.W.
> Calgary, Alberta
> T2R 1J4
> Attention: Ms. Erin Durtnall
> Phone: (403) 750-2564 Facsimile: (403) 265-7488
> Email: Edurtnall@bonterraenergy.com

# APPENDIX “A”

**FORM 51-101F2**
**REPORT ON RESERVES DATA**
**BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

**Report on Reserves Data**

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

1. We have evaluated the Company's reserves data as at December 31, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, 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 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 by us as of December 31, 2024, 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, 2024 | Canada | Nil | 1,362,283 | Nil | 1,362,283 |

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented 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 the 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 Bonterra Energy Corp. (As of December 31, 2024)”

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 7, 2025

(signed) Gary R. Finnis, P. Eng.
Senior Manager, Engineering

(signed) Pavitra Iyer, P. Eng.
Team Lead, Engineering

# APPENDIX "B"

**FORM 51-101F3**
**REPORT OF MANAGEMENT AND DIRECTORS**
**ON OIL AND GAS DISCLOSURE**

**Report of Management and Directors on Reserves Data and Other Information**

Management of Bonterra Energy Corp. (the "Company") is 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, 2024, 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 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 board of directors of the Company 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 approved:

a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

c) the content and filing of this report.

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

(signed) "Patrick G. Oliver"
Patrick G. Oliver, Chief Executive Officer

(Signed) "Scott A. Johnston"
Scott A. Johnston, Chief Financial Officer

(Signed) "Brad A. Curtis"
Brad A. Curtis, Senior VP Business Development

(Signed) "Stacey E. McDonald"
Stacey E. McDonald, Director

(Signed) "Jacqueline R. Ricci"
Jacqueline R. Ricci, Director

(Signed) "John J. Campbell"
John J. Campbell, Director

(Signed) "D. Michael G Stewart"
D. Michael G. Stewart, Director

(Signed) "David M. Humphreys"
David M. Humphreys, Director

March 13, 2025

# APPENDIX "C"

## AUDIT COMMITTEE CHARTER

**PURPOSE**

1. The purpose of the Audit Committee (the "**Committee**") of the Board of Directors (the "**Board**") of Bonterra Energy Corp. (the "**Company**") is to provide an open avenue of communication between management, the Company's independent auditors and the Board and to assist the Board in overseeing:

   a) the integrity, adequacy and timeliness of the Company's financial reporting and disclosure practices;

   b) the Company's compliance with legal and regulatory requirements related to financial reporting; and

   c) the independence and performance of the Company's independent auditors.

2. The Committee shall also perform any other activities consistent with this Charter, the Company's By-laws and governing laws as the Committee or Board deems necessary or appropriate.

3. The Committee's role is one of overseeing. Management is responsible for preparing the Company's financial statements and other financial information and for the fair presentation of the information set forth in the financial statements in accordance with International Financial Reporting Standards (IFRS). Management is also responsible for establishing internal controls and procedures and for maintaining the appropriate accounting and financial reporting principles and policies designed to assure compliance with accounting standards and all applicable laws and regulations.

4. The independent auditors' responsibility is to audit the Company's financial statements and provide their opinion, based on their audit conducted in accordance with Canadian generally accepted auditing standards, that the financial statements present fairly, in all material respects, the financial position, and its financial performance and its cash flows in accordance with IFRS.

5. The Committee is responsible for recommending to the Board the independent auditors to be nominated for the purpose of auditing the Company's financial statements, preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, and for reviewing and recommending the compensation of the independent auditors. The Committee is also directly responsible for the evaluation of and oversight of the work of the independent auditors. The independent auditors shall report directly to the Committee.

**AUTHORITY**

6. The Committee may delegate, from time to time, to any individuals or sub-committees of the Committee, any of the Committee's responsibilities that lawfully may be delegated.

7. In carrying out its duties and responsibilities, the Committee shall have the authority to:

a) meet with and seek any information it requires from employees, officers, directors, or external parties, such as the Company's external auditors;

b) investigate any matter relating to the Company's nomination and corporate governance practices, or anything else within its scope of responsibility;

c) obtain full access to all Company books, records, facilities and personnel; and

d) at its sole discretion and at the Company's expense, retain and set the compensation for outside legal or other advisors, as necessary to assist in the performance of its duties and responsibilities.

8. The Company will provide appropriate funding, as determined by the Committee, for compensation to any advisors that the Committee chooses to engage and for payment of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

9. Management is at all times charged with the obligation to manage day to day operations of the Company and nothing herein shall derogate from that responsibility. The Committee’s role shall be one of reviewing the particular matter and recommending a course of action to the full Board.

## COMPOSITION

10. The Committee shall be composed of not less than three directors. The Board shall appoint the members of the Committee.

11. All of the members of the Committee shall be directors who are independent within the meaning of National Instrument 52-110 – Audit Committees ("**NI 52-110**") and the rules of any stock exchange or market on which the Company’s shares are listed or posted for trading (and any successor legislation) (collectively, "**Applicable Governance Rules**"). In this charter, the term "independent" includes the meanings given to similar terms by Applicable Governance Rules, including the terms "non-executive", "outside" and "unrelated" to the extent such terms are applicable under Applicable Governance Rules.

12. If a matter that is considered by the Committee is one in which a member of the Committee, either directly or indirectly, has a personal interest, that member shall recuse himself or herself from any portion of a meeting at which such matter is discussed and shall not vote on such matter.

13. Each member of the Committee shall be "financially literate". In order to be financially literate, a director must be able to read and understand financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Company's financial statements.

14. A director appointed by the Board to the Committee shall be a member of the Committee until replaced by the Board or until his or her resignation. A director shall automatically cease to be a member of the Committee as soon as such member ceases to be a director of the Company.

15. The Board shall designate the Chair of the Committee.

**MEETINGS OF THE COMMITTEE**

16. The Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chairman of the Committee and whenever a meeting is requested by the Board, a member of the Committee, the auditors, or an executive officer of the Company. Meetings of the Committee shall correspond with the review of the quarterly financial statements and management's discussion and analysis.

17. Notice of each meeting of the Committee shall be given to each member of the Committee and to the auditors, who shall be entitled to attend each meeting of the Committee and shall attend whenever requested to do so by a member of the Committee.

18. The quorum for a meeting of the Committee is a majority of the members. With the exception of the foregoing quorum requirement, the Committee may determine its own procedures.

19. A member or members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

20. In the absence of the Chairman of the Committee, the members of the Committee shall choose one of the members present to be Chairman of the meeting. In addition, members of the Committee shall choose one of the persons present to be the Secretary of the meeting.

21. The management representatives that hold any of the following positions shall be invited to attend all meetings, except private Committee sessions and private sessions with the independent auditors:

    a) Chief Executive Officer;
    b) Chief Financial Officer;
    c) Chief Operating Officer;
    d) Senior Vice President, Business Development;
    e) Vice President, Engineering;
    f) Vice President, Marketing; and
    g) Vice President, Finance

22. The Chairman of the Board, executive management and other parties may attend meetings of the Committee; however the Committee (i) shall meet with the external auditors independent of management; and (ii) may meet separately with management.

23. Minutes shall be kept of all meetings of the Committee.

**DUTIES AND RESPONSIBILITIES**

24. In addition to the foregoing, in performing its oversight responsibilities the Committee shall:

a) Monitor the adequacy of this Charter and recommend any proposed changes to the Board on an annual basis.

b) Review the appointments of the Chief Financial Officer and any other key financial executives involved in the financial reporting process.

c) Identify and monitor the management of the principal risks that could impact the financial reporting of the Company.

d) Review with management and the independent auditors the adequacy and effectiveness of the Company's accounting and financial controls and the adequacy and timeliness of its financial reporting processes.

e) Review with management and the independent auditors the annual financial statements and related documents and review with management the unaudited quarterly financial statements and related documents, prior to filing or distribution, including matters required to be reviewed under applicable legal or regulatory requirements.

f) Where appropriate and prior to release, review with management any news releases that disclose annual or interim financial results or contain other significant financial information that has not previously been released to the public.

g) Review the Company's financial reporting and accounting standards and principles and significant changes in such standards or principles or in their application, including key accounting decisions affecting the financial statements, alternatives thereto and the rationale for decisions made.

h) Review the quality and appropriateness of the accounting policies and the clarity of financial information and disclosure practices adopted by the Company, including consideration of the independent auditors' judgment about the quality and appropriateness of the Company's accounting policies. This review may include discussions with the independent auditors without the presence of management.

i) Review with management and the independent auditor significant related party transactions and potential conflicts of interest.

j) Pre-approve all non-audit services to be provided to the Company by the independent auditors and applicable fees.

k) Inspect any and all of the books and records of the Company and its affiliates.

l) Discuss with the management of the Company and its affiliates and staff of the Company, any affected party, contractors and consultants of the Company and the external auditors, such accounts, records and other matters as any member of the Committee considers necessary and appropriate.

m) At the earliest opportunity after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.

n) When there is to be a change of external auditors, review all issues and provide documentation related to the change, including the information to be included in the Notice of Change of Auditors and documentation required pursuant to NI 51-102 (or any successor legislation) of the Canadian Securities Administrators and the planned steps for an orderly transition.

o) Review all securities offering documents (including documents incorporated therein by reference) of the Company.

p) Review findings, if any, from examinations performed by regulatory agencies with respect to financial matters.

q) Review management's procedure for monitoring the Company's compliance with laws and regulations.

r) Review current and expected future compliance with covenants under financing agreements.

s) Review the proposed issuance of debt and equity instruments including public and private debt, equity and hybrid securities, credit facilities with banks and others, and other credit arrangements such as material capital and operating leases. When applicable, the Committee shall review the related securities filings.

t) Monitor the independence of the independent auditors by reviewing all relationships between the independent auditors and the Company and all non-audit work performed for the Company by the independent auditors.

u) Establish and review the Company's procedures for the:

   (i) receipt, retention and treatment of complaints regarding accounting, financial disclosure, internal controls or auditing matters; and

   (ii) confidential, anonymous submission by employees regarding questionable accounting, auditing and financial reporting and disclosure matters.

v) Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Company.

w) Conduct or authorize investigations into any matters that the Committee believes is within the scope of its responsibilities. The Committee has the authority to retain independent counsel, accountants or other advisors to assist it, as it considers necessary, to carry out its duties, and to set and pay the compensation of such advisors at the expense of the Company.

x) Perform such other functions and exercise such other powers as are prescribed from time to time for the audit committee of a reporting issuer in Parts 2 and 4 of

NI 52-110, all other applicable laws and policies and procedures of all applicable regulatory authorities, the Canada Business Corporations Act and the By-laws of the Company.

y) Monitor and review any planned accounting and financial information changes related to emissions and environmental disclosure practices if applicable to the Company. This review may include discussions with the independent auditors without the presence of management.

**REPORTING**

25. The Committee shall report its discussions to the Board by distributing the minutes of its meetings and where appropriate, by oral report at the next Board meeting.

26. The Committee is responsible to annually review, and in its discretion make recommendations to the Board regarding confirmation of or changes to be made to its Charter.