ANNUAL INFORMATION FORM

FEBRUARY 12, 2024

HIGH MARGINS
ZERO CAPITAL
CARBON NEUTRAL

TSX | **PSK**

PRAIRIESKY
ROYALTY LTD

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Cover: Carbon neutral refers to Scope 1 and Scope 2 emissions. For more information, review our PWC Assurance Statement located in the "Responsibility" section of our website at www.prairiesky.com.

Advisories

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form (*AIF*) contains forward-looking information and statements (collectively, *forward-looking statements*). These forward-looking statements, which relate to future events or future performance, are provided to allow readers to better understand PrairieSky Royalty Ltd.'s (*PrairieSky* or the *Company*) business and prospects and may not be suitable for other purposes. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as seek, anticipate, plan, continue, estimate, expect, may, will, project, predict, potential, target, intend, could, might, should, believe and similar expressions (including the negatives thereof). Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes the expectations reflected in the forward-looking statements included in this AIF are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These forward-looking statements speak only as of the date of this AIF. The Company assumes no obligation to revise or update these forward-looking statements except as required pursuant to applicable securities laws.

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

- the Company's objective to generate free cash flow and growth for its shareholders at a relatively low risk and low cost to the Company, and the proposed manner of achieving this objective;

- the Company's dividend policy, the funding of such dividends, the amounts expected to be paid under that policy in the future and the anticipated timing of payment of such dividends;

- the Company's business and growth strategy and the expectation that the Company will be successful in strategically seeking additional crude oil and natural gas royalty assets that provide the Company with medium-term to long-term value enhancement potential;

- the expectation that the Company will be able to successfully encourage third parties to actively develop the Royalty Properties (as defined herein) and the anticipation that only a small percentage of the Company's undeveloped land holdings will expire within one year;

- the expectation that the Company will secure additional leasing and royalty arrangements with operators and lessees on the Royalty Properties;

- the estimated volumes and future net revenues related to the Company's crude oil, natural gas and NGL (as defined herein) reserves and expectations regarding the ability of the Company to add to reserves through third-party development activities and acquisitions undertaken by the Company;

- projected crude oil and natural gas production levels and certain costs and expenses associated with the Royalty Properties;

- the Company's belief that there will be minimal or no operating costs, capital costs, environmental liabilities or reclamation obligations incurred by the Company related to crude oil and natural gas development on the Royalty Properties;

- the status of the Meadowbrook Project, including timing to submit the provincial government application for a Sequestration Lease Agreement and subsequent steps required to achieve operation;

- the performance and characteristics of the Royalty Properties, including additional upside potential of many of the Royalty Properties;

- the timing and amount of capital expenditure programs and well drilling activity by third parties on the Royalty Properties;

- anticipated future crude oil, natural gas, NGL and other applicable commodity prices and currency exchange and interest rates;

- compliance with covenants under the Sustainable Credit Facility (as defined herein) for at least the next 12 months;

- the quarterly dividend rate;

- supply and demand for crude oil, natural gas, and other applicable commodities;

- the primary sources of costs to the Company;

- the taxability of the Company; and

- treatment under governmental regulatory regimes, environmental legislation and tax laws.

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

- the Royalty Properties will not be developed by third parties in the manner anticipated by the Company;

- non-compliance with lease or contractual royalty terms or payment or delivery delinquencies in respect of the Royalty Properties and associated production, including the credit risk associated with such third parties;

- third-party production companies' inability to manage inflationary cost pressures;

- volatility in the demand, supply and market prices for petroleum products as well as other emerging marketable leased products;

- volatility in currency exchange and interest rates;

- long-term reliance on third parties as lessees on the Fee Lands (as defined herein) and the operators and working interest owners on the Royalty Properties;

- the timing of crude oil and natural gas projects, including the timing of the Trans Mountain Pipeline extension and Canadian LNG projects;

- risks and liabilities inherent in crude oil and natural gas operations as well as operations relating to other applicable commodities;

- uncertainties associated with estimating crude oil, natural gas and NGL reserves and future production levels;

- increased costs incurred by the Company or the lessees on the Fee Lands and the operators and working interest owners on the Royalty Properties;

- competition for, among other things, third-party capital and acquisitions of reserves, additional crude oil and natural gas assets and undeveloped lands;

- incorrect assessments of the value of assets and acquisitions by PrairieSky;

- changes in tax laws or royalty or incentive programs relating to the petroleum and natural gas industry;

- risks related to the environment and changing environmental laws and regulations in relation to the operations conducted on the Royalty Properties, including carbon pricing, future climate change regulations and regulations regarding Indigenous consultation and the resulting effects on the industry in general;

- geological, technical, drilling and completions, processing and handling issues (including deductions from PrairieSky's royalty share of production) associated with crude oil and natural gas development activities by third parties;

- claims made or legal actions brought or realized against the Company or its properties or assets;

- a failure by the Company to hire or retain key personnel;

- breaches or failure of information systems and security (including risks associated with cyber-attacks);

- a decrease or elimination of the payment of dividends by the Company as a result of a Board (as defined herein) determination or restrictions under applicable agreements or corporate laws;

- general economic, market and business conditions; and

- the other factors discussed under "*Risk Factors*" herein.

Forward-looking statements are based on a number of factors and assumptions that have been used to develop such statements, but which may prove to be incorrect. Although PrairieSky believes that the assumptions underlying such forward-looking statements are reasonable, it can give no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur. In addition to other factors and assumptions that may be identified in this AIF, assumptions have been made regarding, among other things:

- the ability of the lessees on the Fee Lands and the operators and working interest owners on the Royalty Properties to maintain or increase production and reserves from these properties;
- the ability and willingness of the lessees on the Fee Lands and working interest owners on the Royalty Properties to comply with, and the Company to enforce, lease terms and contractual provisions, as applicable, in order to receive payments in respect of the Royalty Properties;
- the ability of the lessees on the Fee Lands or the operators and working interest owners on the Royalty Properties to operate in a safe, efficient and effective manner;
- the timely receipt of any required regulatory approvals by lessees on the Fee Lands or the operators and working interest owners on the Royalty Properties;
- the willingness and financial capability of the lessees on the Fee Lands and working interest owners on the GORR Lands (as defined herein) to continue to develop and invest additional capital in the Royalty Properties;
- the ability of the lessees on the Fee Lands and working interest owners on the Royalty Properties to obtain financing on acceptable terms to fund exploration and development capital expenditures;
- field production rates, decline rates and the well performance and characteristics of the Royalty Properties;
- the ability to replace and increase crude oil, natural gas and NGL reserves and production associated with the Royalty Properties through third-party development and acquisitions;
- the timing, cost and ability of third parties to access, maintain or expand necessary facilities and/or secure adequate product transportation and storage;
- the ability of the operators of the properties in which the Company has a royalty interest in, to successfully market their respective crude oil, natural gas, and other applicable leased products or, for royalty payments taken-in-kind by the Company, if any, the ability of the Company or a third-party marketer to successfully market the Company's in-kind crude oil, natural gas, and other applicable leased products;
- surface rights access being granted to third parties on the Royalty Properties;
- the ability of the Company to obtain and retain qualified staff, equipment and services in a timely and cost-efficient manner;
- the absence of any material litigation or claims against the Company;

- the general stability of the economic and political environment and the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company has an interest in crude oil and natural gas properties; and

- prices relating to future crude oil, natural gas, NGL and other applicable leased products and currency exchange and interest rates.

Statements relating to reserves are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

GENERAL

Information contained in or otherwise accessible through the Company's website at www.prairiesky.com does not form a part of this AIF and is not incorporated into this AIF by reference, including, for certainty and without limitation, PrairieSky's Sustainability and Responsibility Reports, Task Force on Climate-related Financial Disclosures Reports, as well as the 2019 reference index for Global Reporting Initiative (GRI) and Sustainability Accounting Standards Board (SASB) sustainability disclosures and PrairieSky's Communication on Progress in relation to the UN Global Compact included in the Company's 2022 Sustainability Report which are available on the Company's website at www.prairiesky.com, each of which are referred to in this AIF.

CONVERSION OF NATURAL GAS TO BARRELS OF OIL EQUIVALENT

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (BOE). PrairieSky uses the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 BOE ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the BOE ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio based on the current price of crude oil to natural gas is significantly different from the 6:1 energy equivalency ratio, using a conversion ratio on a 6:1 basis may be misleading as an indication of value.

PRESENTATION OF OIL AND NATURAL GAS RESERVES AND PRODUCTION INFORMATION

All crude oil, natural gas and NGL reserves and other information with respect to the Royalty Properties in this AIF have been prepared and are presented in accordance with NI 51-101 (as defined herein). See "*Reserves and Other Oil and Gas Information - Notes and Definitions*" for additional information.

All acreage information with respect to the Fee Lands, GRT Lands (as defined herein) and GORR Lands in this AIF has been presented on a gross acre basis. For the Fee Lands, gross acres refers to the total percentage of undivided interest acres in which the Company holds fee simple mineral title and the associated mines and minerals rights. For the GRT Lands and GORR Lands, gross acres refers to the total acres related to the leasehold or title interests held by a third party in the lands on which the Company holds the GRT Interests or GORR Interests (each as defined herein). Gross acres for the GRT Lands or GORR Lands do not account for the Company's net GRT Interests or GORR Interests percentage royalty ownership interest held in lands. Gross acreage for Crown Interest Lands (as defined herein) is the acres covered by the lease and the net acres are the Company's working interest share of the gross acres. The presentation of gross acres for the Fee Lands, GRT Lands and GORR Lands is consistent with the presentation by certain of the Company's peers that hold a royalty interest on lands leased to or by third parties.

All references in this AIF to "working interest" means the right granted to a lessee of a property to explore for and produce petroleum and/or natural gas on the leased lands, upon which such lessee bears the operating costs, capital costs, environmental liabilities or reclamation obligations associated with crude oil and natural gas development.

Glossary of Terms

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms shall have the indicated meanings. Certain other terms used in this AIF but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101. For additional definitions relating to oil and gas information (see "*Reserves and Other Oil and Gas Information — Notes and Definitions*"). Words importing the singular include the plural and vice versa and words importing any gender include all genders. A reference to an agreement means the agreement as it may be amended, supplemented or restated from time to time.

2024 Annual General Meeting means the annual general meeting of shareholders scheduled for Monday, April 22, 2024.

ABCA means the *Business Corporations Act* (Alberta) and the regulations thereunder, as amended from time to time;

affiliate or *associate* has the meaning ascribed thereto in the *Securities Act* (Alberta), as amended from time to time;

Board means the board of directors of the Company as it may be comprised from time to time;

CCUS means carbon capture, utilization and storage;

CNRL Parties means collectively, Canadian Natural Resources Limited, Canadian Natural Resources, Canadian Natural Resources Northern Alberta Partnership and CNR Royalty Partnership;

CNRL Royalty Acquisition means the acquisition by the Company from the CNRL Parties of (i) unleased Fee Lands; (ii) leased Fee Lands; and (iii) contractual royalties (including GORR Interests and GRT Interests) pursuant to the royalty assets purchase and sale agreement dated November 8, 2015, entered into between the CNRL Parties and the Company, as amended, pursuant to which the Company completed the CNRL Royalty Acquisition;

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary chapter) as amended from time to time;

Common Shares means the common shares in the capital of the Company;

COVID-19 means the novel coronavirus which was declared a global pandemic by the World Health Organization on March 11, 2020;

Crown Interest Lands means certain lands in which the Company holds or has acquired a lessee interest in a Crown petroleum and/or natural gas lease or licence, as more particularly detailed throughout this AIF, which are undeveloped with no wells, tangibles or other similar liability, and which the Company intends to sell or otherwise exchange for consideration of a GORR Interest;

crude oil means light oil, medium oil and heavy oil, tight oil and bitumen, collectively;

December 2021 Offering means the bought deal treasury offering, pursuant to a short form prospectus of the Company, completed on December 15, 2021, and resulting in the distribution by the Company of 17,169,500 Common Shares (including 2,239,500 Common Shares issued pursuant to the exercise in full of the over-allotment option) at a price of $13.40 per Common Share for aggregate gross proceeds of approximately $230.1 million;

EBITDA means earnings before interest, tax, depletion, depreciation and amortization;

Encana means Encana Corporation, which effective January 24, 2020 became Ovintiv Inc.;

Encana Purchase and Sale Agreement means the royalty business purchase and sale agreement dated May 22, 2014, entered into between Encana and the Company, pursuant to which the Company completed the Encana Royalty Acquisition;

Encana Royalty Acquisition means the acquisition by the Company from Encana of: (i) fee simple mineral title in lands prospective for petroleum, natural gas, NGL and certain other mineral rights located predominantly in central and southern Alberta; (ii) lessor interests in and to leases issued in respect of certain Fee Lands; (iii) royalty interests, including overriding royalty interests, gross overriding royalty interests and production payments on lands located predominantly in Alberta; (iv) the Seismic Licence; and (v) certain other related assets as set forth in the Encana Purchase and Sale Agreement;

ESG means environmental, social and governance;

Fee Lands means lands prospective for petroleum, natural gas and certain other mines and minerals in which the Company holds a fee simple interest as more particularly detailed throughout this AIF;

Freehold Mineral Tax means an annual tax levied by the Government of Alberta on the value of crude oil and natural gas production from non-government owned lands within Alberta;

GLJ means GLJ Ltd., independent qualified reserves evaluators;

GLJ Report means the independent engineering evaluation of the crude oil, natural gas and NGL reserves relating to the Royalty Properties prepared by GLJ with an effective date of December 31, 2023 and a preparation date of January 10, 2024;

GORR Interests means royalty and similar non-working interests (other than GRT Interests and Lessor Interests), including overriding royalty interests, gross overriding royalty interests, net profit interests and production payments on lands;

GORR Lands means certain lands in respect of which the Company holds GORR Interests as more particularly detailed throughout this AIF;

gross means: (i) in relation to the Company's interest in production or reserves, its Lessor Interests, GORR Interests, GRT Interests; (ii) in relation to wells, the total number of wells in which the Company has an interest; and (iii) in relation to properties, the total area in which the Company has an interest;

GRT Interests means a trust or series of trusts settled by indenture or agreement which hold and collect, for the benefit of its unitholders, mineral interests and/or royalty payments in the form of lessor royalties;

GRT Lands means certain lands in which the Company holds GRT Interests as more particularly detailed throughout this AIF;

Heritage Acquisition means the acquisition by the Company from the Heritage Parties of the Heritage Assets;

Heritage Acquisition Agreement means the asset sale agreement dated November 29, 2021 between the Company and the Heritage Parties providing for the Heritage Acquisition;

Heritage Assets means (i) approximately 1.9 million acres of Royalty Properties throughout Alberta, Saskatchewan and Manitoba, including approximately 1.7 million net acres of Fee Lands; and (ii) seismic assets that are complementary to the acquired Royalty Properties mentioned in (i), in each case acquired pursuant to the Heritage Acquisition Agreement;

Heritage Parties means, collectively, Heritage Resource Limited Partnership, Heritage Royalty Resource Corp. and Heritage Manitoba Holdings Inc.;

hydrocarbons means a solid, liquid or gas made up of compounds of carbon and hydrogen in varying proportions;

IPO means the initial public offering of the Company, pursuant to a secondary offering by Encana, completed on May 29, 2014, and resulting in the distribution by Encana of 52,000,000 Common Shares to the public, plus an additional 7,800,000 Common Shares on June 3, 2014, pursuant to the exercise of the over-allotment option granted by Encana to the underwriters of such offering;

Lessor Interests means lessor interests in and to leases that are currently issued in respect of certain Fee Lands;

LNG means liquified natural gas;

Marten Hills Acquisition means the indirect acquisition by the Company, completed on July 19, 2021, of a 5% gross overriding royalty interest on over 76,000 acres in the core Marten Hills Clearwater area of Alberta from Spur for total cash consideration of $155.0 million;

Marten Hills Subco means 2357320 Alberta Ltd., a former wholly-owned subsidiary of the Company;

Meadowbrook Project means the CCUS project being designed to provide safe, cost effective, permanent CO_2 sequestration in which the Company is a partner;

net means: (i) in relation to the Company's interest in production or reserves, its Lessor Interests, GRT Interests, GORR Interests in production or reserves, after deduction of royalty obligations payable to other parties, if any; (ii) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's

Lessor Interest, GRT Interest or GORR Interest in each of its gross wells; and (iii) in relation to the Company's interest in a property, the total acreage in which the Company has an interest multiplied by the interest owned by the working interest owner of the Royalty Property;

NGL means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butane, pentanes plus, condensate and small quantities of non-hydrocarbons;

NI 51-101 means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*;

NI 51-102 means National Instrument 51-102 – *Continuous Disclosure Obligations*;

OPEC+ means the Organization of Petroleum Exporting Countries;

persons means and includes individuals, companies, corporations, limited partnerships, general partnerships, joint stock companies, limited liability companies, joint ventures, associations, trusts, banks, trust companies, pension funds, and other organizations, whether or not legal entities, and governments and agencies and political subdivisions thereof;

petroleum means a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase, and for the purposes of this AIF, includes crude oil and NGL;

Range GP means Range Royalty Management Ltd.;

Range Royalty means Range Royalty Limited Partnership;

Range Royalty Acquisition means the acquisition of all the issued and outstanding units of Range Royalty and all the issued and outstanding shares of Range GP by the Company effective December 19, 2014;

Reorganization means the internal reorganization involving Encana and the Company completed effective December 13, 2013, and the consolidation of Common Shares effective January 31, 2014;

Royalty Properties means collectively, the Fee Lands, the GORR Lands and the GRT Lands;

SAGD means steam assisted gravity drainage;

SEDAR+ means the System for Electronic Document Analysis and Retrieval;

Seismic Licence means the irrevocable, perpetual, royalty-free, non-exclusive licence to certain proprietary seismic data of Encana, granted to the Company by Encana as part of the Encana Royalty Acquisition and pursuant to the Seismic Licence Agreement;

Seismic Licence Agreement means the agreement dated May 27, 2014, entered into between Encana and the Company, pursuant to which Encana granted the Seismic Licence to the Company;

September 2014 Secondary Offering means the secondary offering by Encana, pursuant to a short form prospectus of the Company, completed on September 26, 2014, and resulting in the distribution by Encana of 70,200,000 Common Shares to the public;

shareholder means a holder of Common Shares;

Spur means Spur Petroleum Ltd.;

subsidiary has the meaning ascribed thereto in the ABCA;

Tax Act means the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time; and

TSX means the Toronto Stock Exchange.

Abbreviations and Conversions

In this AIF, the following abbreviations have the meanings set forth below consistent with Appendix B of the COGE Handbook, where applicable:

API	American Petroleum Institute
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
BOE	barrel of oil equivalent
BOE/d	barrels of oil equivalent per day
Mbbl	thousands of barrels
Mbbl/d	thousands of barrels per day
MBOE	thousands of barrels of oil equivalent
MBOE/d	thousands of barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet equivalent
MMBOE	million barrels of oil equivalent
MMbtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
M$	thousands of dollars

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units) consistent with Appendix C of the COGE Handbook:

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	6.292
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Corporate Structure

GENERAL

The Company was incorporated under the ABCA under the name "1786071 Alberta Ltd." on November 27, 2013. In December 2013 and January 2014, the Company undertook the Reorganization. On April 11, 2014, the Company changed its name to "PrairieSky Royalty Ltd." Prior to the completion of the IPO, the Company was a wholly-owned subsidiary of Encana.

On May 29, 2014, the Company completed the IPO. On September 26, 2014, the Company completed the September 2014 Secondary Offering, pursuant to which Encana distributed 70,200,000 Common Shares to the public, representing EnCana's remaining interest in PrairieSky. Following the September 2014 Secondary Offering, Encana no longer held any Common Shares.

On December 19, 2014, the Company acquired all of the issued and outstanding units of Range Royalty and all of the outstanding shares of Range GP in exchange for the issuance of approximately 19.3 million Common Shares. As part of the Range Royalty Acquisition and through a series of transactions: (i) Range Royalty was wound up and distributed its assets to PrairieSky; and (ii) PrairieSky amalgamated with Range GP and continued under the name "PrairieSky Royalty Ltd." PrairieSky is the legal successor in interest to Range Royalty and Range GP.

On November 8, 2017, PrairieSky amalgamated with its wholly-owned subsidiary, 2079323 Alberta Ltd., an immaterial subsidiary established for the sole purpose of acquiring certain royalty interests in Saskatchewan and on April 1, 2019, PrairieSky amalgamated with its wholly-owned subsidiary, MainSail Energy Ltd. PrairieSky is the legal successor in interest following each of these amalgamations.

On January 1, 2022, PrairieSky dissolved its wholly-owned subsidiary Marten Hills Subco, a subsidiary established for the sole purpose of completing the Marten Hills Acquisition, following the distribution of its assets to PrairieSky.

As at December 31, 2023 and the date hereof, PrairieSky has no material subsidiaries.

The issued and outstanding Common Shares are listed and posted for trading on the TSX under the trading symbol "PSK".

General Development of the Business

The following is a summary description of the development of PrairieSky's business for the three most recently completed financial years.

YEAR ENDED DECEMBER 31, 2023

During the year ended December 31, 2023, the Company entered into 202 leasing arrangements with 110 different counterparties, earning bonus consideration of $26.0 million. Leasing activity focused on crude oil and natural gas targets across several plays and areas in Western Canada. The Company completed several acquisitions during the year for aggregate consideration of $58.4 million. Acquisitions focused on undeveloped land primarily in the Mannville, Clearwater and Banff oil plays as well as other emerging plays prospective for crude oil, NGL and natural gas. During 2023, the Company continued to advance its ESG and alternative energy initiatives, including advancing helium opportunities through work permits and leasing options and the Meadowbrook Project in Alberta, in which PrairieSky is a minority partner. The Meadowbrook Project operator is in the final stages of completing the evaluation phase of the Meadowbrook Project under its Carbon Sequestration Evaluation Agreement with the Province of Alberta, which includes testing of the suitability and capacity of the reservoir for safe and permanent CO_2 sequestration and operation of a carbon sequestration hub. Once this evaluation work is completed, they will submit their provincial government application for a Sequestration Lease Agreement, which is the next step in the development and construction of the project to achieve commercial operation.

YEAR ENDED DECEMBER 31, 2022

During the year ended December 31, 2022, the Company entered into 228 leasing arrangements with 119 different counterparties, earning bonus consideration of $16.2 million. Leasing activity focused on crude oil and natural gas targets across several plays and areas in Western Canada. The Company completed several acquisitions during the year for aggregate consideration of $30.6 million. Acquisitions focused on adding undeveloped land primarily in the Mannville, Clearwater and Viking oil plays as well as other emerging plays prospective for crude oil, NGL and natural gas. During 2022, the Company continued to advance its ESG and alternative energy initiatives, including completing a large-scale lithium exploration lease in Saskatchewan for $0.7 million in bonus consideration and participating in the Meadowbrook Project north of Edmonton, Alberta, in which PrairieSky is a minority partner. Project partners received initial government approval and entered into an evaluation permit for the Meadowbrook Project. The Meadowbrook Project operator will also be required to secure other regulatory permits and licenses from the Alberta Energy Regulator in connection with the operation of the project. Carbon capture, utilization and storage is viewed as a critical component of Canada's emissions reduction initiatives. See "*Business of the Company – Governance, Sustainability and Corporate Responsibility*".

YEAR ENDED DECEMBER 31, 2021

During the year ended December 31, 2021, the Company entered into 139 leasing arrangements with 85 different counterparties, earning bonus consideration of $8.3 million. Leasing activity focused on crude oil and natural gas targets across several plays and areas in Western Canada. The Company completed several acquisitions during the year for aggregate consideration of $987.1 million. Acquisitions focused on adding producing royalty assets and undeveloped land primarily in the Deep Basin area of Alberta, the Clearwater play including the Marten Hills Acquisition, adding the Heritage Assets pursuant to the Heritage Acquisition, as well as other emerging plays prospective for crude oil, NGL and natural gas. The Company also completed repurchases and cancellations of Common Shares under its normal course issuer bid(s), acquiring and cancelling an aggregate of 1,666,800 Common Shares during the fiscal year ended December 31, 2021 for aggregate consideration of approximately $22.7 million. See "*Market for Securities*".

Deep Basin Acquisition

On February 23, 2021, the Company completed an acquisition of royalty assets in Western Canada for cash consideration of approximately $45 million (before adjustments). The acquired assets consisted of approximately 640,000 net acres of Royalty Properties in Western Canada, which included 170,000 acres of Fee Land with multizonal leasing, exploration and development potential, approximately 650 BOE per day of then current production (56% natural gas, 33% NGL, 11% oil), and ownership of approximately 3,200 square kilometers of 3D seismic and 3,100 kilometers of 2D seismic covering the acquired assets and PrairieSky's existing Fee Lands. The acquisition was financed using the Company's $150 million unsecured extendible revolving credit facility (*Former Credit Facility*).

Marten Hills Acquisition

On July 19, 2021, the Company completed the Marten Hills Acquisition for cash consideration of $155 million. The Marten Hills Acquisition was financed using the Former Credit Facility. The Marten Hills Acquisition included a royalty interest on Spur's then current production of approximately 10,000 BOE per day and all future production from the Marten Hills Acquisition lands.

August Acquisition

On August 25, 2021, PrairieSky completed the acquisition of 138,000 acres of Fee Land and 125,000 acres of GORR Interests in Central Alberta adding approximately 200 BOE per day of then current royalty production (74% liquids) for total cash consideration of $34.8 million, before adjustments. The acquisition was financed using the Former Credit Facility.

Credit Facility Amendments

On September 29, 2021, PrairieSky increased and extended the Former Credit Facility to $425 million with a syndicate of Canadian banks and incorporated sustainability-linked performance criteria to establish a Sustainability-Linked Credit Facility (*Sustainable Credit Facility*). In conjunction with establishing the Sustainable Credit Facility, PrairieSky extended the term to a maturity date of February 28, 2025. The Sustainable Credit Facility provided for a permitted increase to $500 million, subject to lender consent. See "*Borrowings*".

Heritage Acquisition, December 2021 Offering and Sustainable Credit Facility Amendments

On November 29, 2021, the Company entered into the Heritage Acquisition Agreement providing for the purchase of the Heritage Assets for an aggregate cash purchase price of $728 million (prior to customary closing adjustments).

On December 15, 2021, the Company closed the December 2021 Offering and the Heritage Acquisition. Concurrent with closing the Heritage Acquisition, PrairieSky expanded the Sustainable Credit Facility to $725 million. The expanded Sustainable Credit Facility provides for a permitted increase to $800 million, subject to lender consent. The maturity date of the Sustainable Credit Facility remains February 28, 2025, and pricing and covenants were unchanged. The aggregate purchase price for the Heritage Assets was funded by the proceeds from the December 2021 Offering and drawdowns under the Sustainable Credit Facility. The Heritage Acquisition had an effective date of December 31, 2021.

The Heritage Assets consisted of approximately 1.9 million acres of Royalty Properties throughout Alberta, Saskatchewan and Manitoba, including approximately 1.7 million net acres of Fee Lands with net proved plus probable reserves of 7,530 MMboe (5,676 MMboe net total proved reserves) at December 31, 2021, as estimated by GLJ and included in the independent engineering evaluation of the crude oil, natural gas and NGL relating to the Royalty Properties prepared by GLJ with an effective date of December 31, 2021 and a preparation date of January 24, 2022.

SIGNIFICANT ACQUISITIONS

The Company did not complete any acquisitions that would be considered significant pursuant to NI 51-102 during the year ended December 31, 2023.

Business of the Company

GENERAL

The Company currently has one of the largest independently owned portfolios of fee simple mineral title and oil and gas royalty interests in Canada**.** The Company is focused on encouraging third parties to actively develop the Royalty Properties while strategically seeking additional crude oil and natural gas royalty assets that provide the Company with medium-term to long-term value enhancement potential, including the acquisition of Crown Interest Lands for purposes of complementing the Company's fee title land base and pursuing prospective farmout strategies. The Company does not directly conduct operations to explore for, develop or produce petroleum or natural gas; rather, third party development of the Royalty Properties provides the Company with royalty revenues as petroleum, natural gas and associated substances are produced from such properties. The Company's costs are primarily administrative expenses, corporate income taxes, and production and mineral taxes. Costs related to crude oil and natural gas upstream drilling, equipment, production and asset retirement obligations are not incurred by the Company; instead, these costs are incurred by the third parties who conduct activities on the Royalty Properties.

The Company's objective is to generate free cash flow and growth for its shareholders through indirect oil and gas investment at a relatively low risk and low cost to the Company. The Company strives to achieve this objective by: (i) focusing on organic growth of its royalty revenue from the Royalty Properties; (ii) proactively monitoring and managing its portfolio of Royalty Properties; (iii) generating efficiencies in its business and administration thereof, with a focus on managing controllable costs; and (iv) selectively pursuing strategic business development opportunities that are relatively low risk to the Company and accretive to shareholders.

The Company's revenue stream is derived predominantly from royalties payable by lessees and working interest owners from crude oil and natural gas production on the Royalty Properties and revenues derived from related activities, including lease issuance bonus consideration and lease rentals. The Company actively pursues additional leasing and royalty arrangements with operators and lessees on the Royalty Properties and, from time to time, seeks to expand its portfolio of royalty interests.

Overview of Royalties

Royalty ownership differs significantly from working interest ownership. A working interest owner is responsible for its share of operating costs, capital costs, environmental liabilities and reclamation obligations, usually in proportion to its ownership percentage, and it receives its *pro rata* share of revenue. A royalty owner enjoys the commercial benefit of hydrocarbon production and upside potential from a property, typically with no obligation for operating costs, capital costs, environmental liabilities or reclamation obligations.

The Company's royalty revenues are derived predominantly from: (i) the Lessor Interests on the Fee Lands leased out by the Company and upon which lessees pay lessor royalties to the Company; (ii) the GORR Lands leased by third parties upon which such third parties pay the Company overriding royalties, net profit, production or such other similar forms of royalty encumbrances; (iii) the GRT Lands; and (iv) related activities, including lease issuance bonus consideration and lease rentals.

The Company does not conduct any drilling activity and is not responsible for making any capital expenditures with respect to the Royalty Properties. The Company receives royalty revenue based on the production performance of wells, with the calculation of such royalty revenues payable based, in part, on the market price of oil and/or natural gas and allowances, if any, for certain deductions. Through certain contractual arrangements with third parties, the Company is able to receive its royalty percentage share of production from the Royalty Properties as a physical or "in-kind" delivery of hydrocarbons. The Company currently takes certain crude oil royalty volumes in-kind.

Lessor Interests

The Company's royalty revenue is substantially derived from Lessor Interests in respect of producing wells located on the Company's approximately 9.7 million acres of Fee Lands. For the year ended December 31, 2023, the Lessor Interests provided approximately 65% of the total royalty revenue of the Company, of which royalty revenue derived from production of liquids (crude oil and NGL) and natural gas accounted for approximately 91% and 9%, respectively.

For the year ended December 31, 2023, average net production associated with the Lessor Interests was 14,585 BOE/d, comprised of 29.5 MMcf/d of natural gas production, 8,201 bbl/d of crude oil production and 1,466 bbl/d of NGL production, generating total royalty revenue of $309.8 million. In addition, in 2023, lease rental income associated with the Lessor Interests was $7.6 million and lease issuance bonus consideration was $26.0 million.

GORR Interests

The GORR Lands are governed by contractual arrangements whereby a royalty interest has been reserved out of the working interest production and granted to the Company. The Company receives gross overriding royalties calculated as a share of hydrocarbons produced from the applicable lands. Typically, GORR Interests expire upon the termination of the underlying leases or licences if they are not developed or, where the GORR Lands have been developed and production activity has ceased, well abandonment activities have taken place and the corresponding leases or licences have been surrendered. GORR Interests are typically legal interests in land that run with the GORR Lands in the event the underlying lease is continued or transferred. Under some contractual arrangements, replacement leases may be contemplated by the applicable contract, thereby extending the application of the GORR Interests. Under other contractual arrangements, acquired leases and licences within a geographic area, typically known as an "Area of Mutual Interest", may become governed by the contract.

The granting of a GORR Interest can arise in many instances, including as a result of: (i) the Company farming out working interest rights to another company in exchange for retaining a GORR Interest on production from wells drilled on such lands; (ii) the Company providing capital in exchange for granting of a GORR Interest or converting a participating interest in a joint venture relationship into a GORR Interest; (iii) the Company, as owner of certain Fee Lands that are in a checkerboard pattern, receiving a GORR Interest on offsetting Crown acreage, achieved in exchange for allowing drilling by third parties of longer horizontal wells across sections that include portions of the Fee Lands or in certain cases where a third party has reviewed the Company's seismic data and acquired a lease or licence in respect of the underlying Crown mineral rights; or (iv) various other contractual arrangements.

The Company holds GORR Interests in approximately 8.2 million acres of GORR Lands, substantially all of which are associated with Crown lands. During the year ended December 31, 2023, average net production associated with the GORR Lands was 10,272 BOE/d, comprised of 30.0 MMcf/d of natural gas production, 4,236 bbl/d of crude oil production and 1,036 bbl/d of NGL production, generating total royalty revenue of $164.8 million. In 2023, the GORR Interests provided approximately 35% of the total royalty revenue of PrairieSky.

GRT Interests

The Company holds approximately 0.3 million acres of GRT Lands. The GRT Interests are governed under trustee arrangements made with financial institutions and are held by virtue of trust unit certificates issued by the financial institution to the unitholders. Each trust unit represents a fractional ownership share of the lessor royalty percentage payable out of the mines and minerals fee title interests in the GRT Lands when leases are granted, and in rare instances, may be a fractional ownership of a feetitle.

Crown Interest Lands

The Company holds approximately 25,000 acres of Crown Interest Lands predominantly in Alberta which were acquired to complement the Company's Fee Lands and to build land positions in strategic areas for purposes of royalty interest transactions.

SPECIALIZED SKILLS AND KNOWLEDGE

The Company relies on specialized skills and knowledge to manage the Royalty Properties. The Company employs a strategy of contracting a limited number of consultants and other specialized service providers to supplement the skills and knowledge of its permanent staff in order to manage the Company's business effectively. PrairieSky also strives to be the best by exploring and employing new technology platforms to maximize efficiencies in managing the Royalty Properties and ensuring a best-in-class compliance program.

REORGANIZATIONS

There have been no material reorganizations of the Company since January 1, 2020 or proposed for the current financial year.

PERSONNEL

As of December 31, 2023, the Company had 65 full-time employees and 1 part-time employee.

COMMODITY PRICES

PrairieSky's operational results and financial condition are dependent on the prices received for crude oil and natural gas production. Benchmark crude oil and natural gas prices are determined by supply and demand, which can be impacted by many factors, including weather and general economic conditions, as well as egress and processing constraints and conditions in other crude oil and natural gas regions. Canadian crude oil, natural gas and NGL can also be affected by regional factors which may result in significant pricing discounts relative to global benchmark prices. Declines in commodity prices adversely affect PrairieSky's business and financial condition. See "*Risk Factors – Prices, Markets and Marketing*".

CYCLICAL AND SEASONAL NATURE OF INDUSTRY

The level of activity in the Canadian petroleum and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain crude oil and natural gas producing properties 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 variability in exploration and production activity during certain parts of the year and corresponding variability in production from the Royalty Properties.

ENVIRONMENTAL CONSIDERATIONS

PrairieSky, as a royalty owner, has no direct exposure to environmental claims and regulations and the associated costs. Environmental matters do however impact the lessees and/or operators of the Royalty Properties and therefore indirectly impact PrairieSky. PrairieSky relies on the lessees and/or operators of the Royalty Properties to be in compliance with current environmental rules and regulations set by the provincial and federal governments in Canada. Failure to comply with environmental regulations could result in the imposition of material fines or penalties on the working interest owners and/or the operators or the curtailment of production which may negatively impact the Company's business and financial condition, which negative impact could prove to be material over time.

COMPETITIVE CONDITIONS

PrairieSky's business is tied to the petroleum and natural gas industry, which is highly competitive at all levels. Although PrairieSky does not drill wells, own facilities or operate oil and gas assets, it competes with other companies for certain business inputs, access to commodity markets, acquisition opportunities, available capital and staffing. PrairieSky strives to be competitive by maintaining a strong financial condition, focusing on building and maintaining strong relationships with high quality lessees, and identifying new geological plays and ways to enhance development and recovery of hydrocarbons to maximize the value on the Royalty Properties. Management believes that the Company's land ownership structure, and a weighting towards fee simple mineral title ownership, provides a significant competitive advantage compared to other royalty companies.

Our core values define what is important to us and are at the foundation of how PrairieSky carries on business. While PrairieSky does not operate, develop or produce any oil and gas assets on the Royalty Properties, PrairieSky recognizes its business model is dependent on the industry operating in a responsible fashion and it is committed to conducting its business in an economically, socially and environmentally sustainable and responsible manner. By conducting its business responsibly, actively managing risk and upholding the highest standards of governance and ethics, PrairieSky aims to provide long-term shareholder and stakeholder value. The Company approaches its relationships with all stakeholders with integrity and respect, and PrairieSky takes care to select operators that share its core values. Because of the long duration of PrairieSky's assets, successful execution of this strategy is only possible if the Company's lands are developed ethically and responsibly. A detailed description of PrairieSky's corporate reporting initiatives and a discussion of ESG issues, including carbon disclosure, is contained in PrairieSky's 2022 Sustainability Report, which can be found on the Company's website at www.prairiesky.com but is not to be considered part of this AIF. PrairieSky's Task Force on Climate-related Financial Disclosures Reports, as well as the 2019 reference index for Global Reporting Initiative (GRI) and Sustainability Accounting Standards Board (SASB) sustainability disclosures can be found on the Company's website at www.prairiesky.com.

PrairieSky has adopted policies relating to its business conduct, including a business code of conduct, a whistleblower policy, a policy concerning confidentiality, fair disclosure and trading in restricted securities, a human rights policy (as PrairieSky supports the Ten Principles of the United Nations Global Compact with respect to human rights, labour, environment and anti-corruption), a respectful workplace policy, and an environment, climate change, health and safety policy. Additional information relating to these and other policies can be found on the Company's website at www.prairiesky.com and will also be detailed in the Company's information circular and proxy statement for the 2024 Annual General Meeting. A copy of PrairieSky's annual Communication on Progress in relation to the UN Global Compact is included in the Company's 2022 Sustainability Report which is available on the Company's website at www.prairiesky.com.

PrairieSky has advanced several of its ESG and alternative energy initiatives, including completing a large-scale lithium exploration lease in Saskatchewan in 2022, advancing helium opportunities through work permits and leasing options in 2023 and receiving initial government approval for its Meadowbrook CCUS project in Alberta.

The lithium leasing arrangement covers approximately 192 gross sections of land, on which the third-party operator has commenced its first drilling activities. PrairieSky has also identified other potential opportunities for similar mineral specific leasing arrangements in Devonian-aged brine water across Alberta and Saskatchewan.

In Q1 2022, the Meadowbrook Project was selected by Alberta Energy as one of six successful applicants for carbon storage tenure in the industrial heartland near Edmonton, Alberta. The initial project partners for the Meadowbrook Project were Bison Low Carbon Ventures Inc., Enerflex Ltd. and IRC Enterprises Inc. Enerflex Ltd. left the Meadowbrook Project in 2023. The Meadowbrook Project is being designed to provide safe, cost effective, permanent CO_2 sequestration, on a multi-client basis, to existing and new Alberta industries seeking to reduce their emissions through the adoption of CCUS. The Meadowbrook Project operator is in the final stages of completing the evaluation phase of the Meadowbrook Project under its Carbon Sequestration Evaluation Agreement with the Province of Alberta, which includes testing of the suitability and capacity of the reservoir for safe and permanent CO_2 sequestration and operation of a carbon sequestration hub. Once this evaluation work is completed, they will submit their provincial government application for a Sequestration Lease Agreement, which is the next step in the development and construction of the Meadowbrook Project to achieve commercial operation. The Meadowbrook Project operator will also be required to secure other regulatory permits and licenses from the Alberta Energy Regulator in connection with the operation of the Meadowbrook Project.

PrairieSky received industry leading scores from several globally recognized rating agencies for 2023. These results demonstrate our ongoing commitment to environmental stewardship, social responsibility, and governance. PrairieSky was once again ranked as "Negligible Risk" by Sustainalytics receiving the "2024 Industry Top-Rated Badge" and receiving the "2024 ESG Global Top-Rated Badge" which is awarded to the top 50 ranked companies in Sustainalytics' ESG Risk Ratings universe which covers more than 14,000 companies across 42 industries. PrairieSky received a score of "B" on the 2023 CDP Climate Change survey, indicating the Company has addressed the environmental impacts of their business and ensures good environmental management. PrairieSky was also included in "The Sustainability Yearbook 2024" for corporate sustainability excellence as assessed through S&P's Global Corporate Sustainability Assessment. PrairieSky also maintained its "AAA" rating and "Leader" MSCI ESG Risk Rating status in 2023.

Reserves Data and Other Oil and Gas Information

DISCLOSURE OF RESERVES DATA

In accordance with NI 51-101, the reserves data associated with the Royalty Properties set forth below is based upon an evaluation prepared by GLJ with an effective date of December 31, 2023, and preparation date of January 10, 2024, as set forth in the GLJ Report. The GLJ Report evaluated the crude oil, natural gas and NGL reserves associated with the Royalty Properties as at December 31, 2023. The tables below summarize the reserves and the net present value of future net revenue attributable to the reserves as evaluated in the GLJ Report based on the arithmetic average of the standard price forecasts from three leading Canadian oil and gas evaluation consulting firms (GLJ, McDaniel & Associates Consultants Ltd., and Sproule Associates Limited) effective January 1, 2024.

The tables summarize the data contained in the GLJ Report and as a result, may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the reserves is stated without provision for interest costs and administrative costs, but after providing for estimated royalties and production and mineral taxes. Future net revenues are presented on a before- and after-tax basis. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the reserves estimated by GLJ represents the fair market value of the reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. There can be no assurance that such price and cost assumptions will be attained and variances could be material. Other assumptions have been made by GLJ and qualifications related to the costs and other matters are included in the GLJ Report. The recovery estimates of the reserves provided herein are estimates only and there is no guarantee that the reserves, as estimated, will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

In preparing the GLJ Report, GLJ relied on certain information provided by third parties associated with the Royalty Properties, which included working and net revenue interest data, public data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, financial data and future development and operating plans for the Royalty Properties, as applicable. Other engineering, historical production, geological or economic data required to conduct the evaluation and upon which the GLJ Report are based was obtained from public records and from non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by GLJ as represented.

The Report on Reserves Data by GLJ in Form 51-101F2 for each of the GLJ Report and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached to this AIF as Appendix A and Appendix B, respectively.

GLJ was engaged by the Company to provide an evaluation of proved and probable reserves. All of the reserves associated with the Royalty Properties are located in the provinces of Alberta, Saskatchewan, British Columbia and Manitoba. As the Company does not hold any working interests in the Royalty Properties, the Company is not responsible for any capital costs associated with the Royalty Properties and, as such, the evaluation of reserves data does not include any undeveloped reserves.

Reserves Data as of December 31, 2023 Forecast Prices and Costs[1]

Summary of Reserves

	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil		Bitumen		Conventional Natural Gas	
	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)
Reserves Category	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(MMcf)*	*(MMcf)*
Proved										
Developed Producing	-	8,518	-	6,984	-	604	-	1,198	-	102,229
Developed Non-Producing	-	636	-	936	-	93	-	428	-	1,939
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	-	9,155	-	7,920	-	697	-	1,626	-	104,167
Total Probable	-	2,746	-	2,749	-	238	-	589	-	27,773
Total Proved Plus Probable	-	11,900	-	10,670	-	935	-	2,215	-	131,940

	Shale Gas		Coal Bed Methane		Natural Gas Liquids		Total Oil Equivalent	
	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)
Reserves Category	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(Mbbl)*	*(Mbbl)*	*(MBOE)*	*(MBOE)*
Proved								
Developed Producing	-	14,498	-	36,208	-	5,176	-	47,970
Developed Non-Producing	-	1,541	-	-	-	258	-	2,931
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	16,039	-	36,208	-	5,434	-	50,900
Total Probable	-	4,870	-	9,354	-	1,539	-	14,861
Total Proved Plus Probable	-	20,909	-	45,563	-	6,973	-	65,762

** Numbers may not add due to rounding.*

Notes:
(1) Based on the GLJ Report. Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions - Forecast Prices and Costs*".
(2) Gross reserves represent the Company's interest in reserves before deduction of royalties and without including any royalty interests.
(3) Net reserves represent the Company's interest in reserves after deduction of royalty obligations plus the Company's royalty interests in reserves.
(4) The Company differs from typical crude oil and natural gas producers in that all of its interests in reserves are royalty interests with no associated working interests. As a result, there are no gross reserves associated with the Royalty Properties, which may hinder comparison of the Company's reserves with others in the petroleum and natural gas industry.

Summary of Net Present Values of Future Net Revenue

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)[1] 0%	5%	10%	15%	20%	Unit Value Before Income Tax Discounted at 10%/year[2]	
	M$	*M$*	*M$*	*M$*	*M$*	*$/BOE*	*$/Mcfe*
Proved							
Developed Producing	2,292,201	1,720,734	1,389,087	1,173,368	1,021,911	28.96	4.83
Developed Non-Producing	189,158	155,246	133,026	117,284	105,513	45.39	7.56
Undeveloped	-	-	-	-	-	-	-
Total Proved	2,481,359	1,875,981	1,522,113	1,290,651	1,127,424	29.90	4.98
Total Probable	899,325	486,949	317,712	231,677	181,263	21.38	3.56
Total Proved Plus Probable	3,380,684	2,362,929	1,839,825	1,522,329	1,308,686	27.98	4.66

** Numbers may not add due to rounding.*

Reserves Category	Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)[1] 0%	5%	10%	15%	20%
	M$	*M$*	*M$*	*M$*	*M$*
Proved					
Developed Producing	2,068,836	1,537,820	1,233,801	1,037,949	901,390
Developed Non-Producing	144,046	118,016	101,095	89,148	80,230
Undeveloped	-	-	-	-	-
Total Proved	2,212,882	1,655,837	1,334,896	1,127,098	981,621
Total Probable	695,451	372,442	241,967	176,151	137,719
Total Proved Plus Probable	2,908,333	2,028,278	1,576,863	1,303,248	1,119,339

** Numbers may not add due to rounding.*

Notes:
(1) Based on the GLJ Report. Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions - Forecast Prices and Costs*".
(2) Unit values are based on Company net reserves.

Additional Information Concerning Future Net Revenue (Undiscounted) as of December 31, 2023

Reserves Category	Revenue[1]	Royalties[2]	Operating Costs[3]	Capital Development Costs[3]	Aband. & Recl. Costs[3]	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	M$	*M$*	*M$*	*M$*	*M$*	*M$*	*M$*	*M$*
Proved								
Developed Producing	2,302,851	10,650	-	-	-	2,292,201	223,364	2,068,836
Developed Non-Producing	197,503	8,344	-	-	-	189,158	45,113	144,046
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	2,500,353	18,994	-	-	-	2,481,359	268,477	2,212,882
Total Probable	901,387	2,062	-	-	-	899,325	203,874	695,451
Total Proved Plus Probable	3,401,740	21,056	-	-	-	3,380,684	472,351	2,908,333

** Numbers may not add due to rounding.*

Notes:
(1) Based on the GLJ Report. Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions - Forecast Prices and Costs*".
(2) Production and mineral taxes payable.
(3) The Company does not hold any working interests in the Royalty Properties. As such, the Company is not responsible for any operating, development or abandonment and reclamation costs associated with estimated net revenues from the reserves attributed to the Royalty Properties.

Future Net Revenue by Production Type as of December 31, 2023 – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes(1)(2) (Discounted at 10% per year)		
	M$	**$/BOE**	**$/Mcfe**
Proved Producing			
Light Crude Oil & Medium Crude Oil (combined)(3)	560,206	48.78	8.13
Heavy Crude Oil(3)	349,546	46.93	7.82
Tight Oil(3)	9,836	55.54	9.26
Bitumen(3)	66,837	55.07	9.18
Conventional Natural Gas(4)	252,760	13.99	2.33
Shale Gas(4)	79,709	22.73	3.79
Coal Bed Methane	70,193	11.57	1.93
Total Proved Producing	1,389,087	28.96	4.83
Total Proved			
Light Crude Oil & Medium Crude Oil (combined)(3)	607,309	48.89	8.15
Heavy Crude Oil(3)	397,863	47.16	7.86
Tight Oil(3)	9,899	55.58	9.26
Bitumen(3)	89,575	54.56	9.09
Conventional Natural Gas(4)	255,740	14.01	2.34
Shale Gas(4)	91,538	23.43	3.91
Coal Bed Methane	70,190	11.57	1.93
Total Proved	1,522,113	29.90	4.98
Total Proved Plus Probable			
Light Crude Oil & Medium Crude Oil (combined)(3)	729,239	45.11	7.52
Heavy Crude Oil(3)	493,099	43.36	7.23
Tight Oil(3)	12,381	51.11	8.52
Bitumen(3)	116,884	52.28	8.71
Conventional Natural Gas(4)	297,284	12.92	2.15
Shale Gas(4)	110,820	21.70	3.62
Coal Bed Methane	80,118	10.49	1.75
Total Proved Plus Probable	1,839,825	27.98	4.66

** Numbers may not add due to rounding.*

Notes:
(1) Based on the GLJ Report. Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions - Forecast Prices and Costs*".
(2) Other Company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company net reserves.
(3) Including solution gas and other by-products.
(4) Including by-products but excluding solution gas.

For future net revenue of the total proved reserves before income taxes, discounted at 10%, 73% of the revenue is from combined crude oil and 27% is from combined natural gas. For the total proved plus probable reserves, 73% of the future net revenue before income taxes, discounted at 10%, is from combined crude oil and 27% is from combined natural gas.

In the tables set forth above and elsewhere in this AIF, the following notes and other definitions are applicable.

Reserve Categories

The determination of crude oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable 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 judgment 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 are required to properly use and apply reserves definitions.

Reserves are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- within specified economic conditions.

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

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

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

Each of the reserves categories may be divided into developed and undeveloped categories.

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities, or, if facilities have not been installed, that would involve a low expenditure (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.

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

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

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (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 category (proved, probable) to which they are assigned.

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

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to "individual 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 reserves estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

PRICING ASSUMPTIONS — FORECAST PRICES AND COSTS

GLJ employed the following then current pricing, inflation rate and exchange rate assumptions based on the arithmetic average of the standard price forecasts from three leading Canadian oil and gas evaluation consulting firms (GLJ, McDaniel & Associates Consultants Ltd., and Sproule Associates Limited) effective January 1, 2024.

	Crude Oil						
Year	**WTI Cushing, Oklahoma**	**Edmonton Par Price 40° API**	**Hardisty Bow River**	**Hardisty Western Canadian Select**	**Hardisty Heavy Oil 12° API**	**Cromer Light Sour 35° API**	**Exchange Rate(1)**
	($US/bbl)	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($US/$Cdn)***
2024	73.67	92.91	77.44	76.74	69.01	93.35	0.752
2025	74.98	95.04	80.48	79.77	71.90	95.50	0.752
2026	76.14	96.07	81.84	81.12	72.78	96.53	0.755
2027	77.66	97.99	83.61	82.88	74.41	98.46	0.755
2028	79.22	99.95	85.78	85.04	76.56	100.43	0.755
2029-2033	84.10	106.11	91.05	90.28	81.30	106.62	0.755
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	0.755

Year	Natural Gas AECO/NIT Spot	Alberta Natural Gas Liquids Spec Ethane	Edmonton Propane	Edmonton Butane	Edmonton Pentane Plus	Inflation Rate[(2)]
	($/MMbtu)	*($/bbl)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*(%/year)*
2024	2.20	6.88	29.65	47.69	96.79	2.0
2025	3.37	10.76	35.13	48.83	98.75	2.0
2026	4.05	13.16	35.43	49.36	100.71	2.0
2027	4.13	13.44	36.14	50.35	102.72	2.0
2028	4.21	13.71	36.87	51.35	104.78	2.0
2029-2033	4.47	14.58	39.13	54.52	111.23	2.0
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2.0

Notes:
(1) Exchange rates used to generate Canadian benchmark reference prices in this table.
(2) Inflation rates for forecasting.

During 2023, average sales prices realized in respect of the production associated with the Royalty Properties were $2.60/Mcf for natural gas, $82.52/bbl for crude oil and $47.60/bbl for NGL.

RESERVES RECONCILIATION

A requirement of NI 51-101 is the provision of a reconciliation on a gross reserves basis. Due to the Company's unique asset base, the tables setting forth the reconciliation of gross reserves do not provide adequate information and are potentially misleading. Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include any royalties receivable. Net reserves are working interests minus royalties payable plus royalties receivable. As substantially all of the Company's assets are royalty interests, they would be excluded in a gross reconciliation table. The Company believes this would hinder an investor's ability to compare PrairieSky's reserves to others in the same industry.

The following reserve reconciliation table is provided as an aid to the investor. The table is based on net reserves and is consistent with disclosure presented by other entities in the royalty business.

Reconciliation of Company Net Reserves by Principal Product Type – Forecast Prices and Costs

	Light and Medium Crude Oil			Heavy Crude Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
December 31, 2022	9,524	2,703	12,226	8,338	2,549	10,886
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	1,562	398	1,960	1,414	414	1,827
Technical Revisions	225	(360)	(136)	(94)	(215)	(309)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	18	5	23	14	2	16
Production	(2,173)	-	(2,173)	(1,752)	-	(1,752)
December 31, 2023	9,155	2,746	11,900	7,920	2,749	10,670

	Tight Oil			Bitumen		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
December 31, 2022	749	290	1,038	1,183	401	1,584
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	140	38	178	790	208	997
Technical Revisions	16	(91)	(76)	49	(22)	27
Acquisitions	-	-	-	10	2	12
Dispositions	-	-	-	-	-	-
Economic Factors	1	2	3	1	-	-
Production	(208)	-	(208)	(406)	-	(406)
December 31, 2023	697	238	935	1,626	589	2,215

	Conventional Natural Gas			Shale Gas		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(MMcf)*
December 31, 2022	107,075	27,864	134,940	15,893	5,390	21,283
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	5,121	1,112	6,233	2,913	389	3,303
Technical Revisions	7,916	(1,350)	6,566	(312)	(912)	(1,224)
Acquisitions	6	1	7	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(223)	145	(78)	(4)	2	(2)
Production	(15,728)	-	(15,728)	(2,451)	-	(2,451)
December 31, 2023	104,167	27,773	131,940	16,039	4,870	20,909

	Coal Bed Methane			Natural Gas Liquids		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	*(MMcf)*	*(MMcf)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
December 31, 2022	37,899	8,415	46,314	5,619	1,610	7,229
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	503	56	559
Technical Revisions	1,848	941	2,788	234	(125)	109
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(2)	(1)	(3)	(9)	(1)	(10)
Production	(3,536)	-	(3,536)	(913)	-	(913)
December 31, 2023	36,208	9,354	45,563	5,434	1,539	6,973

	Total Oil Equivalent		
	Proved	**Probable**	**Proved Plus Probable**
	(MBOE)	***(MBOE)***	***(MBOE)***
December 31, 2022	52,222	14,497	66,719
Discoveries	-	-	-
Extensions & Improved Recovery	5,748	1,363	7,111
Technical Revisions	2,005	(1,034)	971
Acquisitions	11	3	14
Dispositions	-	-	-
Economic Factors	(14)	32	19
Production	(9,072)	-	(9,072)
December 31, 2023	50,900	14,861	65,762

**Numbers may not add due to rounding.*

PrairieSky's total proved plus probable reserves were 65,762 MBOE at December 31, 2023 with reserves additions related to extensions and improved recovery factors replacing approximately 78% of production. Drilling extensions added 6,928 MBOE of proved plus probable reserves primarily a result of development activity in the Clearwater, Viking, and Mannville oil plays. Notable new third-party heavy oil drilling activity took place in the Cold Lake area of Alberta using multi-lateral horizontal drilling techniques as well as incremental third-party drilling at the Lindbergh thermal oil project. Liquids-rich Montney natural gas drilling activity in the Wembley area of Alberta provided the largest additions to natural gas and NGL proved and probable reserves. Expansion of secondary recovery via waterflooding in the Clearwater was the largest contributor to improved recovery additions of 183 MBOE proved plus probable reserves. Net technical revisions of 971 MBOE proved plus probable reserves were primarily attributed to positive revisions in shallow natural gas assets which were partially offset by negative revisions in certain Montney assets.

Acquisitions contributed an incremental 14 MBOE of proved plus probable reserves additions and an additional 19 MBOE of proved plus probable reserves additions were related to economic factors.

Overall, total proved reserves volumes decreased 2.5% as operator drilling, improved recovery factors, economic factors and net positive technical revisions were offset by production. Total proved plus probable reserves volumes decreased 1.4%, as operator drilling, improved recovery factors, economic factors and net positive technical revisions were also offset by production.

SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting crude oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The reserves were evaluated by GLJ who is an independent qualified reserves evaluator.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing economic or regulatory environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end crude oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative.

FUTURE DEVELOPMENT COSTS

Funding for development costs is the responsibility of the working interest owners on the applicable properties. The Company does not hold any oil and natural gas working interests in the Royalty Properties and is not responsible for any oil and natural gas development costs on the Royalty Properties. No future development capital is considered in the Company's reserve evaluation and the Company cannot advise as to the sources and costs of funding future development or the impact thereof on disclosed reserves or future net revenue.

OIL AND NATURAL GAS PROPERTIES AND WELLS

The following tables summarize the gross number of oil and natural gas wells located on the Royalty Properties in which the Company holds a royalty interest, all of which are located in British Columbia, Alberta, Saskatchewan and Manitoba, and all of which are onshore. As the Company does not hold any oil and natural gas working interests in the Royalty Properties or related infrastructure, the net number of wells, or ownership in properties or facilities located on the Royalty Properties is nil.

	Natural Gas(1)		Oil(1)	
Area	**Producing**	**Non-Producing(2)**	**Producing**	**Non-Producing(2)**
Alberta	21,135	-	7,685	-
Saskatchewan	5,755	-	7,377	-
British Columbia	284	-	18	-
Manitoba	2	-	1,050	-

Notes:
(1) Includes unit wells.
(2) Royalty revenues payable by third parties are based on oil and natural gas producing wells located on the Royalty Properties. The Company does not have information from third parties on non-producing oil and natural gas wells located on the Royalty Properties.

PROPERTIES WITH NO ATTRIBUTED RESERVES

The following table summarizes the undeveloped land holdings of the Company with no attributed reserves as at December 31, 2023 and the acreage which is subject to a lease term expiry within one year.

	Fee Lands(1)(2)	GRT Lands(1)(2)	GORR Lands(3)(4)		Crown Interest Lands(3)(4)		
(thousands of acres)	**Gross Acres**	**Gross Acres(3)**	**Gross Acres**	**Gross Acres expiring within one year**	**Gross Acres**	**Net Acres**	**Net Acres expiring within one year**
Alberta	4,650	47	2,902	124	23	23	4
Saskatchewan	1,454	84	371	38	2	2	-
British Columbia	-	1	314	30	-	-	-
Manitoba	681	1	-	-	-	-	-
Other	1	-	63	-	-	-	-
Total	6,785	134	3,650	192	25	25	4

** Numbers may not add due to rounding.*

Notes:
(1) Fee lands with multiple leases under the same surface area have been calculated on an aerial basis, and as such have only been counted once.
(2) The petroleum and/or natural gas rights associated with certified title to Fee Lands and GRT Lands under superior trust agreements are held in perpetuity. The number of uncertified titles and inferior trust agreements held by the Company are *de minimus*. As such, there is no meaningful number of gross acres for which the Company's interests will expire during 2024.
(3) Undeveloped lands are calculated by adding the surface area covered by individual leases or agreements. In certain limited circumstances where the Company holds interests under the same surface area pursuant to different leases or agreements, the acreage with respect to all such leases or agreements are added together.
(4) Some of this acreage may qualify to be continued by the working interest owners pursuant to other operations on the lands or offsetting lands as allowed by the regulations. Additionally, although the Company does not directly conduct operations on these lands, it makes every possible effort to have third parties actively develop the lands prior to lease expiries and therefore anticipates only a small percentage of this acreage to expire during this period.

TAX HORIZON

The Company is presently cash taxable. The statutory corporate income tax rate applicable to the Company in 2023 was approximately 23.6% and the Company recognized current income taxes of $58.8 million in net earnings. A corporation's taxable income is based on total revenue, expenses and other deductions, which in the case of the Company will vary depending on the amount of royalty revenue received as a result of fluctuations in commodity prices and development activities on the properties in which it holds interests, as well as other revenues related to leasing activity on Fee Lands. At December 31, 2023, the Company had $1.4 billion of tax pools which can be used to offset future taxable income.

COSTS INCURRED

The following table sets out the Company's property acquisition costs, seismic acquisition costs and acquisition transaction costs for the year ended December 31, 2023.

Expenditures	Year Ended December 31, 2023 ($millions)
Property Acquisition Costs:	
Proved Properties	12.4
Unproved Properties	44.7
Seismic Acquisitions	1.3
Acquisition transaction costs	-
Total	58.4

PRODUCTION ESTIMATES

The following table discloses for each product type the gross and net volume of production estimated by GLJ for the year ended December 31, 2024, in the estimates of gross and net proved and gross and net probable reserves disclosed above under the heading "*Reserves and Other Oil and Gas Information — Disclosure of Reserves Data*".

Reserves Category	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil		Bitumen	
	Gross(1)(2)	Net(3)(4)	Gross (1)(2)	Net(3)(4)	Gross(1)(2)	Net (3)(4)	Gross(1)(2)	Net(3)(4)
	(bbl/d)		*(bbl/d)*		*(bbl/d)*		*(bbl/d)*	
Proved								
Developed Producing	-	4,092	-	3,777	-	345	-	1,001
Developed Non-Producing	-	526	-	591	-	73	-	247
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	4,618	-	4,368	-	418	-	1,248
Total Probable	-	378	-	356	-	42	-	113
Total Proved Plus Probable	-	4,996	-	4,724	-	460	-	1,361

Reserves Category	Natural Gas						NGL	
	Conventional		Shale Gas		Coal Bed Methane			
	Gross(1)(2)	Net(3)(4)	Gross(1)(2)	Net(3)(4)	Gross(1)(2)	Net(3)(4)	Gross(1)(2)	Net(3)(4)
	(Mcf/d)		*(Mcf/d)*		*(Mcf/d)*		*(bbl/d)*	
Proved								
Developed Producing	-	35,974	-	5,640	-	9,131	-	2,053
Developed Non-Producing	-	1,640	-	765	-	-	-	260
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	37,614	-	6,404	-	9,131	-	2,313
Total Probable	-	1,677	-	494	-	105	-	147
Total Proved Plus Probable	-	39,291	-	6,899	-	9,235	-	2,460

Reserves Category	Total Oil Equivalent Gross[1][2]	Net[3][4]
	(BOE/d)	
Proved		
Developed Producing	-	19,725
Developed Non-Producing	-	2,098
Undeveloped	-	-
Total Proved	-	21,823
Total Probable	-	1,415
Total Proved Plus Probable	-	23,238

** Numbers may not add due to rounding.*

Notes:
(1) Gross production represents the Company's interest in production before deduction of royalties and without including any royalty interests.
(2) The Company differs from crude oil and natural gas producers in that all of its interests in reserves are royalty interests with no associated working interests. As a result, there are no gross reserves associated with the Royalty Properties, which may hinder comparison of the Company's reserves with others in the petroleum and natural gas industry.
(3) Net production represents the Company's interest in production after deduction of royalty obligations plus the Company's royalty interests in production.

PRODUCTION HISTORY

The following table summarizes production, product prices received, royalties paid (production and mineral tax expense), cash administrative expenses and resulting operating netback for the periods indicated below.

	Annual 2023	2023 Q4	Q3	Q2	Q1
Average daily production[1]					
Natural Gas *(MMcf/d)*	59.5	60.4	64.1	53.8	59.6
Crude Oil (*bbl/d*)	12,438	12,844	12,084	12,607	12,212
NGL *(bbl/d)*	2,502	2,697	2,702	1,943	2,664
Total *(BOE/d)*	24,857	25,608	25,469	23,517	24,809
Average price realized[2]					
Natural Gas *($/Mcf)*	2.60	2.19	1.97	2.23	4.05
Crude Oil (*$/bbl*)	82.52	83.27	92.53	78.05	76.25
NGL *($/bbl)*	47.60	46.07	52.01	44.77	46.71
Total *($/BOE)*	52.31	51.78	54.37	50.65	52.31
Production and mineral tax expense					
Natural Gas *($/Mcf)*	0.08	0.09	0.07	0.04	0.11
Crude Oil (*$/bbl*)	1.03	1.04	0.95	1.04	1.10
NGL *($/bbl)*	-	-	-	-	-
Total *($/BOE)*	0.71	0.72	0.64	0.65	0.81
Cash administrative expenses[3]					
Natural Gas *($/Mcf)*	0.99	0.44	1.42	0.61	1.44
Crude Oil (*$/bbl*)	5.80	2.66	8.55	3.66	8.63
NGL *($/bbl)*	-	-	-	-	-
Total *($/BOE)*	5.28	2.38	7.64	3.36	7.70
Operating netback received[4]					
Natural Gas *($/Mcf)*	1.53	1.66	0.47	1.58	2.50
Crude Oil (*$/bbl*)	75.69	79.58	83.03	73.36	66.52
NGL *($/bbl)*	47.60	46.07	52.01	44.77	46.71
Total *($/BOE)*	46.32	48.68	46.09	46.64	43.80

Notes:
(1) Represents net production.
(2) Excludes sulphur and other revenue.
(3) PrairieSky does not incur operating expenses. Cash administrative expenses, which are administrative expenses excluding non-cash share-based compensation, include expenses associated with land administration, accounting and auditing functions

necessary to administer and collect royalty payments and are allocated to natural gas and oil based on each product's share of total product revenue. Cash administrative expenses include any cash settled share-based compensation in the period. Cash administrative expenses are then divided by the average production (or commodity) in the period to generate a cash margin per unit sold. Cash administrative expenses are a non-GAAP measure as defined in the Company's management's discussion and analysis for the periods ended March 31, 2023 (under the section "*Non-GAAP Measures and Ratios*" starting at page 19), June 30, 2023 (under the section "*Non-GAAP Measures and Ratios*" starting at page 21), September 30, 2023 (under the section "*Non-GAAP Measures and Ratios*" starting at page 21) and December 31, 2023 (under the section "*Non-GAAP Measures and Ratios*" starting at page 25), each of which sections are incorporated by reference in this AIF. The Company's management's discussion and analysis for each of the periods noted above are available on SEDAR+ at www.sedarplus.ca under PrairieSky's company profile.

(4) Operating netbacks are calculated by subtracting royalties paid (production and mineral tax expense) and cash administrative expenses from royalty revenues. This amount is then divided by the average production (or commodity) in the period to generate a cash margin per unit sold. Operating netback is a non-GAAP measure which is defined in the Company's management's discussion and analysis as operating netback for the periods ended March 31, 2023 (under the section "*Financial Results – Operating Results*" starting at page 6 and under the section "*Non-GAAP Measures and Ratios*" starting at page 19), June 30, 2023 (under the section "*Financial Results – Operating Results*" starting at page 7 and under the section "*Non-GAAP Measures and Ratios*" starting at page 21), September 30, 2023 (under the section "*Financial Results – Operating Results*" starting at page 7 and under the section "*Non-GAAP Measures and Ratios*" starting at page 21), and December 31, 2023 (under the section "*Financial Results – Operating Results*" starting at page 7 and "*Non-GAAP Measures and Ratios*" starting at page 25), each of which sections are incorporated by reference in this AIF. The Company's management's discussion and analysis for each of the periods noted above are available on SEDAR+ at www.sedarplus.ca under PrairieSky's company profile.

DESCRIPTION OF PROPERTIES

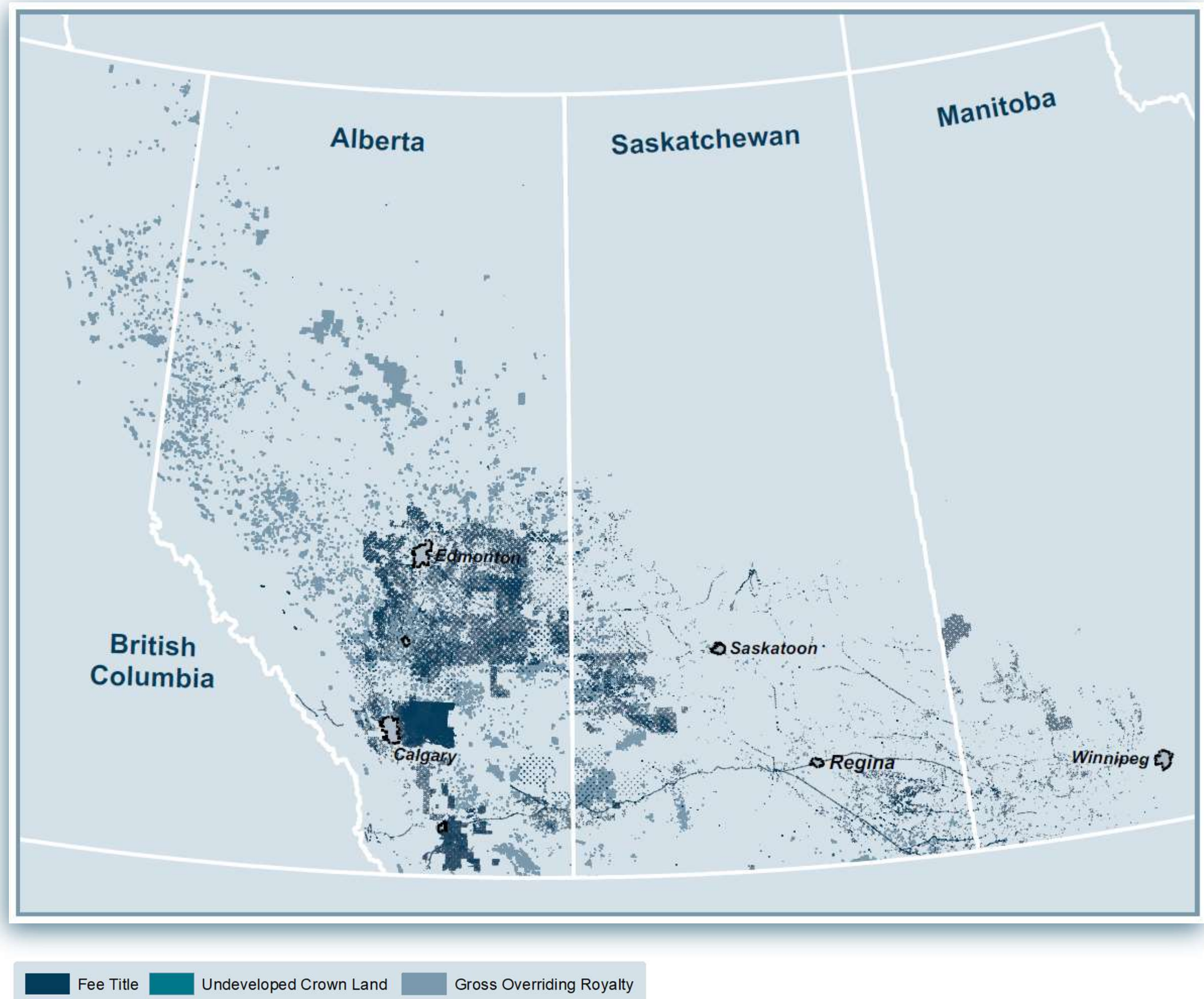
The assets of PrairieSky are comprised of: (i) the Fee Lands, encompassing approximately 9.7 million acres; (ii) the Lessor Interests; (iii) the GORR Interests, encompassing approximately 8.2 million acres of the GORR Lands; (iv) the GRT Interests, encompassing approximately 0.3 million acres of the GRT Lands; (v) approximately 25,000 acres of Crown Interest Lands; (vi) the Seismic Licence and other proprietary seismic data together encompassing approximately 54,200 kilometres of 2D seismic and approximately 20,100 square kilometres of 3D seismic with coverage over 5.0 million acres; and (vii) certain other related assets.

The Fee Lands are located in the Western Canadian Sedimentary Basin, predominantly in the provinces of Alberta and Saskatchewan.

Over 15,900 leases are currently active on the Fee Lands and over 375 lessees are engaged in exploring for and producing crude oil and natural gas on the Fee Lands.

Map of PrairieSky Fee Lands, GORR Interests and Other Interests

Below is a map of the Royalty Properties indicating those lands which are Fee Lands, GORR Interests (including GRT Interests) and Crown Interest Lands as at December 31, 2023.



Lands

The Company has one of the largest independently-owned portfolios of fee simple mineral title in Canada with approximately 11.1 million acres of Fee Lands, of which approximately 9.7 million acres are comprised of petroleum and/or natural gas rights. For the period ended December 31, 2023, royalty revenue from the Fee Lands accounted for approximately 65% of the total royalty revenue of PrairieSky. In addition, all bonus consideration and lease rentals are earned from Fee Lands.

The Fee Lands include a geologically diverse portfolio of properties that span the stratigraphic column from surface to basement. There is potential for the same section of land to be leased and re-leased on the basis of geological grouping, therefore allowing multiple lessees the right to drill and explore for, and ultimately produce from, different formations depending on the particulars of their leasing arrangement. Geological groups that form part of the Fee Lands include: (i) Surface to Top Colorado, focusing on shallow gas and Belly River oil development; (ii) the Colorado Group, which includes the Cardium Formation and the Viking Formation in both Alberta and Saskatchewan; (iii) the Mannville Group, which includes the Detrital/Basal-Quartz/Ellerslie/Ostracod, as well as the Glauconitic Formation and Upper Mannville Fahler/Wilrich/Notikewin; (iv) the Jurassic to Base Mississippian, which includes the Rock Creek, Nordegg, Rundle Group, Banff, Midale and Bakken Formations; and (v) the Devonian, which includes the Nisku and the Duvernay Formations.

GORR Lands

The Company holds GORR Interests in approximately 8.2 million acres of GORR Lands. The substantial majority of the GORR Lands were acquired in connection with the Range Royalty Acquisition and the CNRL Royalty Acquisition, with additional GORR Lands acquired in targeted plays. Most recent drilling activities on the GORR Lands were predominantly focused on the Viking Formation in Southwestern Saskatchewan and Alberta, the Wilrich and Duvernay Formations at Edson, the Lloydminster, Cummings and Rex Formations in Central Alberta as well as on both the Lindbergh and Onion Lake thermal projects, the Clearwater sands in North Central Alberta, the Duvernay Formation at Willesden Green, the Montney/Doig, Cardium, Spirit River and Dunvegan in the Deep Basin and the Montney/Doig in northeast British Columbia.

GRT Lands

The Company holds approximately 0.3 million acres of GRT Lands which represent minor fractional shares of lessor royalty interests reserved out of fee title lands throughout the Western Canadian Sedimentary Basin.

Crown Interest Lands

The Company holds approximately 25,000 acres of Crown Interest Lands, predominately in Alberta, which were acquired to complement the Company's checkerboard fee title position and to build land positions in strategic areas for purposes of royalty interest transactions.

CERTAIN OTHER MINES AND MINERAL RIGHTS

Coal rights, precious stone and other mines and mineral rights, including lithium and potash, in addition to crude oil and natural gas, are included in substantially all the Fee Lands. Due to the low commodity price outlook of coal, current estimates of mining and transportation costs in Alberta, or lack of commercial development at this time, the Company does not currently consider coal, precious stone or these other mineral rights material to its business.

Borrowings

At December 31, 2023, PrairieSky had the Sustainable Credit Facility, consisting of a $700 million extendible revolving credit facility (the *Revolving Facility*), with a permitted increase to $775 million, subject to lender consent, and an unsecured $25 million extendible operating credit facility (the *Operating Facility*) with a syndicate of Canadian banks. The Sustainable Credit Facility includes borrowing options of Canadian prime rate-based advances, U.S. base rate advances, bankers' acceptances and letters of credit, and bears interest on a variable grid based on certain financial ratios, over the prevailing applicable rate for the type of loan. The Sustainable Credit Facility is unsecured and does not have a borrowing base restriction. The Sustainable Credit Facility has three financial covenants, whereby the Company's ratio of adjusted consolidated senior debt to EBITDA for the trailing 12 months will not exceed 3.5:1.0, adjusted consolidated total debt to EBITDA for the trailing 12 months will not exceed 4.0:1.0, and the adjusted consolidated total debt to capitalization ratio will not exceed 55%. EBITDA used in the covenant calculation is net earnings adjusted for non-cash items, interest expense and income taxes. All covenants are calculated as at, and for the 12 months ended December 31, 2023. EBITDA for the trailing 12 months has been adjusted for material acquisitions as defined in the Sustainable Credit Facility agreement. As at December 31, 2023, the Company was compliant with all covenants provided for in the lending agreement and forecasts compliance with such covenants for at least the next 12 months.

On September 29, 2021, among other amendments, PrairieSky incorporated sustainability-linked performance criteria into the Former Credit Facility to establish the Sustainable Credit Facility. Sustainability performance criteria is measured by Sustainalytics, a global leader in independent ESG research, ratings and analytics, using the Sustainalytics management score on an annual basis. The Sustainable Credit Facility includes a pricing feature whereby the Company may incur positive or negative pricing adjustments on drawn and undrawn balances based on changes to the management score. PrairieSky's ESG performance was re-evaluated in early 2023 and 2024 and the maximum 5 basis points pricing reduction was maintained. In conjunction with establishing the Sustainable Credit Facility, PrairieSky extended the term to a maturity date of February 28, 2025. There were no changes to the financial covenants in the September 29, 2021 amendments. The Company had previously amended the Credit Facility on January 29, 2021 and July 15, 2021.

On December 15, 2021, the Company expanded the Sustainable Credit Facility to its current capacity, in part, to finance the purchase price of the Heritage Acquisition.

As at December 31, 2023, the Company had $188.5 million drawn on its Sustainable Credit Facility.

Industry Conditions

Companies carrying on business in the petroleum and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and, with respect to the pricing and taxation of crude oil and natural gas, through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian petroleum and natural gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. While such regulations do not affect the Company's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such legislation, regulations and agreements carefully.

The unique nature of the Royalty Properties is expected to allow the Company to benefit from the upside potential of such properties at a reduced risk relative to traditional exploration and production companies. This advantage is a result of collecting royalty payments in respect of the Royalty Properties rather than directly conducting operations to explore for, develop or produce petroleum or natural gas, which has a higher regulatory burden. However, legislation and regulations, including those outlined below, may impact the royalties received by the Company as an indirect participant in the development of crude oil and natural gas on its Royalty Properties. In addition, if the strategy of the Company were to change in the future such that it becomes a direct participant in the development of its properties, whether as a working interest owner or an operator in respect of the Fee Lands that are currently undeveloped, or otherwise, the aforementioned industry regulation would become the burden of the Company in respect of such development. The discussion below outlines certain pertinent conditions and regulations that impact the petroleum and natural gas industry in Western Canada.

PRICING AND MARKETING IN CANADA

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance, and contractual terms of sale.

Following the COVID-19 pandemic, the oil markets began to rebalance in 2021 with oil prices reaching their highest levels in six years. The rebound continued into 2022 with a surge in oil prices in early 2022. This was primarily driven by the impact of the Russian invasion of Ukraine and the OPEC+ decision to adhere to previously agreed-upon production cuts. Additionally, the global economic conditions and outlook improved due to reducing and easing COVID-19 restrictions. In June 2023, OPEC+ producers agreed to target lower oil supply up until the end of 2024 in order to stabilize the price of oil. In anticipation of a potential surplus, in November 2023, OPEC+ producers agreed to a voluntary cut in output for the first quarter of 2024.

While the trajectory of oil prices continue to be subject to uncertainty and volatility, factors such as transportation disruptions, supply constraints and the conflict in Ukraine continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Risk Factors – Exposure to Widespread Pandemic and Risks Related Thereto*", See "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Prices, Markets and Demand for Petroleum Products*".

During the early summer months of 2023, wildfire activity impacted Canadian crude production throughout the second quarter. In addition, many facilities experienced lengthy maintenance updates, which resulted in lower overall production. Despite the setbacks, it has been forecasted that Canadian oil and gas producers will drill 8% more wells in 2024, taking advantage of greater access to pipelines, signaling a ramp-up in growth and demand for crude oil production in the country. The anticipated growth in exports and crude oil prices is supported by the progress of the Trans Mountain Pipeline which is expected to increase the pipeline's capacity by 590,000 barrels per day, to a total of 890,000 barrels per day.

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/demand balance and other contractual terms of sale. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural gas prices are expected to remain subdued for the first few months of 2024 in light of the predicted warmer 2024 winter. Exceptionally high production levels in both Canada and the U.S., alongside storage reserves in Europe and North America, have collectively contributed to maintaining lower natural gas prices.

Natural Gas Liquids

The pricing of condensates and other NGL, including ethane, butane, propane and pentane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGL extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGL, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance, and other contractual terms of sale.

Exports from Canada

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

Exports of crude oil, natural gas and NGL from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the *Part VI Regulation*) until the Part VI Regulation is replaced. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas not exceeding 30,000 m^3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). With respect to applications for long-term export licences, following a review of such applications by the CER, which may involve a public hearing, the CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes do not exceed Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences also currently require various other ministerial and federal Cabinet approvals.

Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government.

Transportation Constraints and Market Access

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGL is the deficit of transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation and export projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. These setbacks are primarily due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity and as a result, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

PIPELINES

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers and the price received.

Under the Canadian Constitution, interprovincial and international pipelines fall within the federal government's jurisdiction. Under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty. Consequently, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments, public interest groups and legal opposition. These issues often relate to Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes and assessments. 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 such regulatory uncertainty, the Canadian petroleum and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGL, including pipelines, rail, trucks, and marine transport. Improved access to global markets through the midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

Specific Pipeline Updates

Line 3 Replacement

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, Enbridge Inc.'s (*Enbridge*) Line 3 Replacement Project (the *Line 3 Replacement*) from Hardisty, Alberta, to Superior, Wisconsin, faced significant challenges in getting to operation. The U.S segment of the pipeline replacement was delayed due to permitting issues, particularly following the Minnesota Pollution Control Agency's announcement requiring a public hearing concerning a key water permit. In June 2021, the Minnesota Court of Appeals affirmed the Minnesota Utilities Commission’s decision to grant Enbridge a certificate of need and a pipeline routing permit for the final segment of the Line 3 Replacement. The Minnesota Supreme Court declined to hear an appeal on this matter. After more than eight years, on September 29, 2021 Enbridge announced the completion of the 542 km Minnesota segment of the Line 3 Replacement. The Line 3 Replacement's in-service date was October 1, 2021 and Line 3 transports 760,000 barrels per day at full capacity.

In October 2022, a Minnesota District Court upheld approvals given to the Line 3 Replacement, which were challenged on the basis that the U.S. Army Corps of Engineers should have taken into consideration how the broader project would impact climate change. The U.S. Army Corps of Engineers limited their environmental review of the project only to the impacts of construction in Minnesota rather than downstream concerns such as greenhouse gas (*GHG*) emissions from the ultimate burning of the crude oil carried in the pipeline.

Line 5 Tunnel Replacement Project

In December 2023, Michigan Regulators approved Enbridge's Line 5 Tunnel Replacement Project (*Line 5*), marking the end of a more than three year long evaluation process. Line 5 is seen as crucial infrastructure supplying Michigan, Ontario and Québec. This approval begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straights of Mackinac. The pipeline will be housed within a concrete tunnel beneath the lakebed. The tunnel project must first be approved by the U.S. Army Corps of Engineers at the United States federal level before construction can commence. The U.S. Army Corps of Engineers has initiated an environmental impact assessment, which is expected to be completed by 2026.

Trans Mountain Pipeline

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's (now the CER) environmental assessment and the federal government's Indigenous consultations. The Federal Court of Appeal quashed the approval and directed Cabinet to correct the deficiencies. After reassessment by the NEB and enhanced consultation efforts led by the federal government, Cabinet reapproved the Trans Mountain Pipeline expansion. Subsequent challenges of the approval were rejected by the federal Court of Appeal in February 2020 and the Supreme Court of Canada (*SCC*) in July 2020.

In addition, on April 25, 2018, the Government of British Columbia submitted a reference question to the British Columbia Court of Appeal, asking whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the *BC EMA*) to impose a permitting requirement on carriers of heavy crude within British Columbia. The reference was appealed and ultimately dismissed by the SCC, finding the proposed amendments were outside provincial jurisdiction.

The Trans Mountain Pipeline expansion project faced a series of construction-related challenges throughout the third and fourth quarters of 2023. In September 2023, Trans Mountain faced a potential nine-month delay over a reroute approval in the Jacko Lake area near Kamloops, British Columbia, due to difficulties identified during the tunnel drilling process. The request was opposed by the Stk'emlupsemc Te Secwepemc Nation (*SSN*) First Nation, whose territory the pipeline crosses. The SSN argued that changing the route would disturb lands that hold "profound spiritual and cultural significance". After a three day hearing, the CER approved the route change request on a 1.3-kilometer section of the pipeline. Following the CER's release of the reasons for its decision, the SSN has not filed an appeal or a variance request.

Construction commenced on the Trans Mountain Pipeline expansion in late 2019 and mechanical completion of the project is now expected to occur in the second quarter of 2024. In November 2023, Trans Mountain faced another regulatory hearing on a pipeline variance request of a section of pipeline between Hope and Chilliwack, British Columbia. Trans Mountain applied for a variance request due to very challenging conditions, including the hardness of the rock that needed to be drilled. Trans Mountain requested permission to change the diameter, wall thickness, and coating for a 2,300-meter stretch of the pipeline, differing from its initial approval. The CER ordered Trans Mountain to attend an oral hearing in November of 2023 to provide further information or justification. In early December 2023, the CER denied the variance request, causing a potential two-year delay and additional losses. On January 12, 2024, the CER reversed its decision, approving the request for change, allowing construction to continue.

Keystone KL Pipeline

TC Energy Corporation's (*TC Energy*) Keystone XL Pipeline was expected to begin construction in the first half of 2019. However, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. On March 31, 2020, TC Energy announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US$1.1 billion equity investment in the project and would guarantee a US$4.2 billion project level credit facility.

While construction on the Keystone XL Pipeline started in April 2020, the Keystone XL Pipeline remained subject to legal and regulatory barriers in the United States. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block certain permits. On April 15, 2020, a Montana judge ruled against the U.S. Army Corps of Engineers' use of a national permit for water crossings in the United States (*Nationwide Permit 12*). The United States Court of Appeals for the Ninth Circuit refused to stay the ruling. While the Supreme Court of the United States subsequently reinstated Nationwide Permit 12 in July 2020, it determined that the reinstatement would not apply to the Keystone XL Pipeline.

On January 20, 2021, Mr. Joseph Biden was sworn in as the 46th President of the United States, following which the Biden administration announced its decision to revoke the federal permit granted by the previous administration for the Keystone XL Pipeline, which overturned a comprehensive regulatory process that lasted more than a decade. As a result of the revocation, and following a comprehensive assessment of its options and consulting with its partners and stakeholders, including the Government of Alberta, on June 9, 2021, TC Energy terminated the Keystone XL Pipeline project.

The United States presidential election is set to occur in the fall of 2024, which may result in a shift in the political agenda in the United States in the coming years, including a change in control of the house and/or the senate. Uncertainty remains as to the advancement of pipeline projects between Canada and the United States.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the Oil Tanker Moratorium Act, which imposes a ban on tanker traffic transporting certain crude oil and NGL or persistent crude oil products in excess of 12,500 metric tonnes along British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbl/d of crude oil out of the province to help alleviate the transportation constraints impacting Canadian oil prices.

In the spring of 2019, the Government of Alberta announced it would cancel the program and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020, that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in early April 2020 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits announced in February 2020 within metropolitan areas, with further mandatory speed reductions applying outside of metropolitan areas during winter months (November 15 to March 15). As of January 2024, no permanent rules have been approved.

Natural Gas and LNG

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. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. (*NGTL*) pipeline network (the *NGTL System*) to prioritize deliveries into storage (*temporary service protocol*). The change served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. An expansion to the NGTL System was recommended for approval by the CER, which was sent to the federal Cabinet for final approval. On April 30, 2021, the Governor in Council approved the issuance of the certificate of public convenience by the CER. Construction began on the NGTL System in 2021 with a majority of the project components reaching in-service for firm contracts in early 2023. It is anticipated that all project components will reach in-service in the first quarter of 2024.

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

In January 2022, the CER issued its decision denying NGTL's application for a proposed firm transportation linked service from receipt points along the North Montney Mainline in Northeast British Columbia to the proposed Willow Valley Interconnect delivery point. In its decision the CER stated the tolling methodology proposed would result in unjust and unreasonable tolls.

In August 2023, TC Energy sought regulatory approval for a potential minority interest sale of its NGTL System. The sale would result in a restructuring in order to facilitate potential future minority ownership of the system, including possible participation from Indigenous groups. As of the date of this AIF, no decision has been announced. TC Energy has begun discussions with Indigenous groups regarding a potential sale.

Development of both provincial and federal frameworks may also impose restrictions on natural gas and LNG projects in Canada, particularly as provincial and federal governments work to achieve emissions reduction targets.

On January 26, 2024, the Biden Administration announced a temporary pause on pending decisions on exports of LNG to non free trade agreement countries until the Department of Energy can update the underlying analysis for authorizations, which may increase the need to use Canadian infrastructure to fill the gap, of which the projects are still in development.

Specific Pipeline and Proposed LNG Export Terminal Updates

Coastal GasLink Pipeline

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, opposition from environmental and Indigenous groups and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. The Coastal GasLink pipeline (the *CGL Pipeline*) was built by TC Energy, construction of which began in 2018. In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline faced intense legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays to construction activities on the CGL Pipeline.

In October 2023, it was announced that the 670 kilometre pipeline installation had been completed ahead of its year-end target. The project will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the CGL Pipeline. Once in service, 17 First Nations that are situated along the pipeline route have signed an agreement for the option to buy a 10% stake in the project.

Woodfibre LNG Project

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project (the Woodfibre LNG Project).The project was proposed as a joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited, a subsidiary of Woodside Petroleum Ltd. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission (*BC Commission*) approved a project permit for the Woodfibre LNG Project in July 2019. In April 2022, a Notice to Proceed was issued, instructing the contractor to begin the work required to move the project toward major construction commencement in 2023. In July 2022, Pacific Energy Corporation Limited and Enbridge entered into a partnership agreement to jointly invest in the construction and operation of the Woodfibre LNG Project.

In November 2022, proposals were made to amend certain conditions listed in the project's Decision Statement (which informs the proponent about the determination made by the Minister or the Governor in Council), concerning technical feasibility. These proposed amendments were then issued for public comment. On November 9, 2023, the British Columbia Environmental Assessment Office (*BC EAO*) approved the amendment to the environmental assessment certificate for the Woodfibre LNG Project to allow for a temporary floating worker accommodation, or 'Floatel', as well as its associated mooring, access infrastructure, and onshore drinking-water treatment facility. The 'Floatel' is expected to arrive in 2024. On July 31, 2023, the project officially commenced construction on the first of the proposed eighteen modules for the project. The Woodfibre LNG Project is expected to be substantially completed in the third quarter of 2027.

The Énergie Saguenay Project

GNL Québec Inc., the proponent of the Énergie Saguenay project (the *Énergie Saguenay Project*), is currently working its way through a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on the Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026; however, on February 7, 2022 the Impact Assessment Agency of Canada (the *IA Agency*) concluded that the project was likely to cause an adverse environmental impact. Although the federal government has rejected the initial plan, GNL Quebec Inc. is not prevented from submitting a new or revised project proposal for authorization. As of the date of this AIF, no revised proposal has been submitted.

Cedar LNG Project

Cedar LNG Export Development Ltd.'s Cedar LNG project (the *Cedar LNG Project*) near Kitimat, British Columbia is set to be the first Indigenous majority owned LNG project in the world. On June 8, 2021 the Haisla First Nation and Pembina Pipeline Corporation (*Pembina Pipeline*) announced a partnership agreement whereby Pembina Pipeline will become the Haisla Nation's partner in the development of the Cedar LNG Project. The BC EAO completed its assessment of the application for an environmental assessment certificate in November 2022 on behalf of the IA Agency. A report of the BC EAO's impact assessment was submitted to the Minister of Environment and Climate Change in November 2022. On March 15, 2023, both the provincial and federal government provided a decision statement indicating the project may proceed. Construction of the project must substantially begin within 5 years of the decision date.

On January 4, 2024, the Haisla Nation and Pembina Pipeline Corporation announced that Samsung Heavy Industries (SHI) and Black & Veatch were selected for engineering, procurement and construction design, and fabrication and delivery of the floating LNG production units. This selection marks a significant advancement for the Cedar LNG Project with the final investment decisions anticipated in the first quarter of 2024. Pending the expected announcement, construction for the project is expected to commence in the second quarter of 2024, targeting the delivery of the floating LNG units by 2028.

Ksi Lisims LNG Project

The Nisga'a Nation, Rockies LNG Limited Partnership and Western LNG are proposing to jointly build the Ksi Lisims LNG natural gas liquefaction and marine terminal project (the *Ksi Lisims LNG Project*). The Ksi Lisims LNG Project is a proposed LNG facility to be located on a site owned by the Nisga'a Nation in British Columbia. The Ksi Lisims LNG Project is currently undergoing a review by the BC EAO following its application for an environmental certificate in October 2023. A public comment period on the Ksi Lisims LNG Project was held from November 1 to December 1, 2023. The BC EAO is conducting the environmental assessment, will review feedback from the public comments and provide direction to the proponents on how to revise their application. Subject to the foregoing, construction is anticipated to begin in 2024 with the site operational in late 2027 or 2028.

THE UNITED STATES MEXICO CANADA AGREEMENT AND OTHER TRADE AGREEMENTS

NAFTA/USMCA

The North American Free Trade Agreement (*NAFTA*) that previously existed among the governments of Canada, the United States and Mexico has been replaced by a new trade agreement, widely referred to as the United States Mexico Canada Agreement (*USMCA*) and sometimes referred to as the Canada United States Mexico Agreement (*CUSMA*). The USMCA came into force on July 1, 2020. Because 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, the implementation of the USMCA could have an impact on Western Canada's petroleum and natural gas industry at large, including the Company's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach other international markets.

Other Trade Agreements

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 recently agreed to the Comprehensive Economic and Trade Agreement (*CETA*), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA has not received full ratification by national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union (*Brexit*) on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement (*CUKTCA*). On December 9, 2020, the Government of Canada introduced Bill C-18, an *Act to Implement the Trade Continuity Agreement*. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021 and CUKTCA came into force on April 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

Canada and 10 other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership (*CPTPP*) on March 8, 2018, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among: Canada, Australia, Japan, Mexico, New Zealand, Singapore, Vietnam, Peru, Malaysia, Chile and Brunei Durussalam. As other countries ratify the agreement, they are added to the annexes. 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.

In August 2023, an updated version of the Canadian Free Trade Agreement (*CFTA*) was published, aiming to revamp the Agreement on International Trade to create a more robust and equitable trade environment within Canada.

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

LAND TENURE

Mineral Rights

The respective provincial governments (i.e. the Crown) predominantly own the mineral rights to most of the crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for, and produce, crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Crude oil and natural gas leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time, and other conditions are satisfied.

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

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown. Such reversionary rights may impact any GORR Interests granted out of Crown leases.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by the federal government on behalf of First Nations or national parks and by private freehold owners, such as the Company. Rights to explore for and produce privately-owned crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop crude oil and natural gas reserves.

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

Until recently, crude oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the *IOGA*) and the *Indian Oil and Gas Regulations, 1995*. In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the *Modernized IOGA*); however, the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the *2019 Regulations*). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019.

On September 26, 2023, the Supreme Court of British Columbia ruled in *Gitxaala v British Columbia* (Chief Gold Commissioner) that British Columbia must consult Indigenous groups before registering mineral claims on their traditional territories under the *Mineral Tenure Act*. The Supreme Court of British Columbia deferred its decision for 18 months, giving time for the Government of British Columbia to create a consultation-based claims system or for government amendments to the *Mineral Tenure Act*. It is possible that this decision will have impacts on the mineral regime in other provinces.

The Fee Lands consist of fee simple mineral titles privately owned by the Company. Certain of the Fee Lands are encumbered and governed, as applicable, by leases granted on such lands. The Lessor Interests consist of the rights of the Company as set forth under such leases.

The GORR Interests are royalty interests that are granted or carved out of leasehold interests (created through the issuance of a lease by the Crown or fee simple mineral title owner). As such, the continued existence and value of the GORR Interests is dependent upon the validity and terms of the leasehold interest out of which they were granted.

In respect of the GORR Interests granted out of Crown leases, in addition to the varying terms and conditions set forth in provincial legislation, as discussed above, the provinces of Alberta, British Columbia, Saskatchewan, and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to non-productive geological formations at the conclusion of the primary term of a lease or licence.

ROYALTIES AND INCENTIVES

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the freehold mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for volume-based incentive programs, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. In addition, incentive 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 NGL, 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 create 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, the terms of which are subject to negotiation.

The Company has the flexibility to negotiate and adapt its royalty arrangements with third parties to affect the profitability of the exploration, development and production of crude oil and natural gas related to its Lessor Interests or GORR Interests in the appropriate circumstances, including consideration of the existing royalty regime established by each province (as described below) and any amendments to that regime.

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights and crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis.

In 2016, the Government of Alberta adopted a modernized Crown royalty framework (the *Modernized Framework*) that applies to all conventional oil (i.e. not oil sands) and natural gas wells drilled after December

31, 2016 that produce Crown-owned resources. The previous royalty framework (the *Old Framework*) will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026. 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.

Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's average drilling and completion costs, determined annually by the AER, and incorporates information specific to each well such as vertical depth and lateral length.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative 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 at a royalty rate 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 and operates on a sliding scale. 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 rate of 5% as the mature well's production declines. As the Modernized Framework 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.

Crude oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* (Alberta) was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three years.

Subject to certain available incentives, royalty rates for conventional crude oil production subject to the Old Framework range from a base rate of 0% to a cap of 40%; royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. 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 meters deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGL is a flat rate of 40% for pentanes and 30% for butanes and propane.

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework does not impact or change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for West Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55/bbl and increase for every dollar by which the market price of crude oil increases to a maximum of 9% when crude oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar by which the market price of crude oil increases above $55/bbl to a maximum of 40% when crude oil is priced at $120/bbl or higher.

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% 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.

British Columbia

In May 2022, the government of British Columbia introduced a new royalty framework that is set to come into effect September 1, 2024 with a two-year transition period that began on September 1, 2022. The new royalty framework will be based on a revenue-minus cost royalty system with price-sensitive royalty rates designed to reflect the value of the resource and achieve a return of 50% of profits after production costs are accounted for. New wells will pay a flat royalty of 5% until the capital spent on drilling and completions is recovered, following which, the well will move to a price-sensitive royalty rate between 5% and 40%. The range of the rate will vary by commodity type. During the transition period, any new wells which are spud on or after September 1, 2022 are not eligible for the deep-well royalty program, the marginal well royalty program or the ultra-marginal royalty program. Wells that are spud on or after September 1, 2022 will pay a 5% royalty rate for the equivalent of the first 12 production months, following which the wells will pay royalties based on the current royalty framework until September 1, 2024 when all the wells transition to the new framework.

Wells drilled prior to September 1, 2022 shall continue to pay royalties based on the current royalty framework until the new framework takes effect on September 1, 2024. The royalties payable by producers in British Columbia will vary depending on the types of wells and the characteristics of the substances being produced.

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 rate can be as high as 40%, depending on factors such as the volume of crude oil produced by the applicable well or tract and the crude oil vintage. 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 NGL 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, NGL 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 NGL and sulphur, the royalty rates are fixed at 20% and 16.667%, respectively. 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.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of crude oil and natural gas from freehold lands in British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

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 NGL and sulphur are flat rates of 12.25% and 10.25%, respectively. 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.

The Ministry of Energy, Mines and Low Carbon Innovation intends to create a mechanism which was originally set to begin in early 2023, giving producers the option to repurpose unused deep well entitlements by transferring them to a Healing Land and Emission Reduction Pool. Once allocated to a producer's pool, the deep well credits will no longer be available to reduce royalties on the well they were originally allocated to. By September 1, 2026, any deep well deductions that have not been used or transferred into a healing land will expire, unless the remaining deductions are used to offset emissions reduction expenditures.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the *Resource Surcharge*) and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. Crown royalties payable on the production of crude oil and natural gas are paid on a well-by-well basis. Producers of crude oil and natural gas receive royalty invoices from the Government of Saskatchewan on a monthly basis. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights acreage tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil, depends on a number of variables including the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGL is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

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. As of April 1, 2021, on associated gas produced from wells other than gas wells, including natural gas produced from oil wells, the Minister of Energy and Resources implemented a five-year Associated Gas Royalty Moratorium on the collection of Crown Royalty and Freehold Production Tax. 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 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.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced.

Manitoba

In Manitoba, the Crown owns only approximately 20% of the crude oil and natural gas rights in the province, with the remainder being freehold lands. The royalty amount payable on crude oil produced from Crown lands depends on the classification of the crude oil produced. Royalty rates on crude oil are calculated on a sliding scale with a range of 0% to approximately 42.8% based on the monthly crude oil production from a spacing unit, or crude oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on crude oil produced from Crown lands is calculated based on the amount of crude oil production allocated to a spacing unit in accordance with the applicable regulations. As such, the royalty payable by producers will vary depending on the underlying characteristics of the producer's assets.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

The Government of Manitoba maintains a Drilling Incentive Program (the *MB Incentive Program*) with the intent of promoting investment in the sustainable development of petroleum resources. The MB Incentive Program provides the licencee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no royalties are payable until the holiday oil volume has been produced. The MB Incentive Program consists of benefits that are specific to certain vertical, exploration and deep wells, as well as wells undergoing major workovers, wells for solution gas and wells converted to injection wells. In December 2022, the MB Incentive Program was extended without alteration for the period commencing January 1, 2023 and ending on December 31, 2024 while the Natural Resources and Northern Development Mining, Oil and Gas Branch reviews the current program.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of crude oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on crude oil is calculated on a sliding scale between 0% and approximately 40% based on the monthly production volume and the classification of crude oil as old oil, new oil, third-tier oil, and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month.

Freehold and Other Types of Non-Crown Land Royalties and Taxes

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 freehold mineral 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), Freehold Mineral Taxes or production taxes are levied on the production of crude oil and natural gas from freehold lands in each of the Western Canadian provinces where the Crown does not hold the mineral rights. A description of the Freehold Mineral Taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

Where crude oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

REGULATORY AUTHORITIES AND ENVIRONMENTAL REGULATION

General

The Canadian petroleum and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain petroleum and natural 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 regulations 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, future changes to environmental legislation, including legislation related to air pollution and greenhouse gas (*GHG*) emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalents (*CO_2e*)), may impose further requirements on operators and other companies in the petroleum and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

Impact Assessment Act

On August 28, 2019, the IAA replaced the *Canadian Environmental Assessment Act, 2012* (*CEAA 2012*) at the same time that the CERA replaced the *National Energy Board Act* (*NEB Act*) and the CER replaced the NEB. As part of the regulatory transition, the IA Agency replaced the Canadian Environmental Assessment Agency (*CEA Agency*).

The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. However, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. Despite this structural change, the CER has assumed the jurisdiction previously held by the NEB over matters such as 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.

The IAA is similar to the repealed CEAA 2012 in that it relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights and peoples. It also requires an expanded public interest assessment, including Indigenous consultation, as applicable. The impact assessment must look at the direct result of the project's construction and operation. Designated projects specific to the petroleum and natural gas industry include pipelines that require more than 75 km of new right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report 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.

In response to the publication of the IAA, the Government of Alberta submitted a reference question to the Alberta Court of Appeal regarding its constitutionality. On May 10, 2022, the Alberta Court of Appeal released its opinion stating that the IAA went beyond the federal Parliament's constitutional authority and reached into areas of exclusive provincial authority. The federal government appealed the Alberta Court of Appeal's opinion to the SCC.

On October 13, 2023, the SCC ruled that the "designated projects" scheme set out in the IAA and its accompanying regulations were unconstitutional. However, the SCC reached a unanimous decision affirming the constitutional validity of the section within the IAA that pertains to projects conducted or funded by federal authorities on federal lands or abroad. The SCC found that "designated projects" under the IAA was unconstitutional as it was seen as overreaching federal authority. This portion of the IAA was criticized for regulating entire projects, rather than focusing solely on areas falling under federal jurisdiction.

This decision has significant implications for the development of natural resources, energy and infrastructure projects in Canada. While the federal government works to bring the IAA into compliance with the guidance as set out by the SCC, the *Impact Assessment Act* (*Interim Guidance*) was enacted, and will remain in place until the IAA is revised. During this interim period, the federal government will not be using its discretionary process to designate projects under the IAA until the legislation has been revised. The Federal Minister of Environment announced it will work with the provinces and Indigenous groups to ensure the impact assessment process works for all. The revisions to the IAA will require that only those projects that can result in adverse federal effects are targeted. Until such time as the revised IAA has been released, proponents must comply with the Interim Guidance. The potential effects that the Interim Guidance, or the revised IAA, may have on the oil and gas industry is unknown.

Clean Fuel Regulations

On July 1, 2023, the Clean Fuel Regulations (CFR) came into force. The objective of the clean fuel standard is to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The CFR requires liquid fossil fuel primary suppliers (i.e. producers and importers) to reduce the carbon intensity (*CI*) of the liquid fossil fuels they produce in, and import into, Canada. The CFR has also established a credit market, whereby the annual CI reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the CI 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 changes involve adding and revising output-based standards (*Standards*), enhancing implementation procedures, refining reporting accuracy, and encouraging voluntary participation. Notably, the updated OBPS introduces a 2% fixed annual tightening rate for most Standards starting from 2023. Sectors facing significant competition and carbon pricing-induced carbon leakage will experience 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 December 7, 2023, the federal government published the *Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap* (*GHG Cap*). Under the GHG Cap, LNG projects would be captured by cap-and-trade system. The provincial and federal governments aim to work together to ensure the regulations and programs complement each other to minimize additional administrative requirements. The key elements of the GHG Cap include: (i) a decline of emissions to meet net-zero by 2050; (ii) creating the legal upper bound on emissions (being the maximum emissions the whole sector may be allowed to emit per year) in a manner responsive to technically achievable emissions reductions and the global demand for oil and gas; (iii) minimal administrative burden; and (iv) ongoing monitoring and regular review of the standards.

In 2024, the federal government plans to publish proposed regulations for a 60-day public comment period. Formal written comments will also be sought on the proposed regulations at that time. The final regulations are expected to be published by 2025. The initial reporting responsibilities could come into effect as early as 2026, while the complete system requirements are set to be gradually implemented between 2026 and 2030.

United Nations Declaration on the Rights of Indigenous Peoples Act

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

Alberta

The Alberta Energy Regulator (the *AER*) is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* (Alberta) 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 (*AUC*) and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its 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. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Protected Areas (previously known as the Ministry of Environment and Parks), the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy 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 effects 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.

British Columbia

In British Columbia, the *Energy Resource Activities Act* (*ERAA*) (formerly the *Oil and Gas Activities Act*) regulates 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 BC Commission has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources and requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, 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 licences, 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 permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The Government of British Columbia has introduced 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 BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the *Oil and Gas Activities Act*, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the *Kiskatinaw Area*). Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is approved by the BC Commission, and notifying the BC Commission and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BC Commission on demand. If a seismic event occurs, permit holders are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude and triggers a sliding scale of obligations from permit holders. The obligations range from reporting the seismic event and developing an approved protocol for subsequent events, to initiating such protocols, to suspending operations until permitted to resume by the BC Commission. Future seismic events outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

An updated *Environmental Assessment Act* came into force on December 16, 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasizes early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" contained in the *Reviewable Projects Regulation* captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the BC EAO 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.

Saskatchewan

The Saskatchewan Ministry of 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 act governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations, 2012* (the *OGCR*) and *The Petroleum Registry and Electronic Documents Regulations* (the *Registry Regulations*). The Government of Saskatchewan has implemented a number of operational requirements, including an 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 partner in the Petrinex database.

The environmental scheme in Saskatchewan is governed by *The Environmental Management and Protection Act, 2010* and *The Forest Resources Management Act*. In Saskatchewan, the ministry has adopted a results-based regulatory model which largely leaves the determination of how environmental protection is to be achieved with the respective proponent.

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. The program currently requires oil and gas companies to retire 5% of their inactive liabilities such as inactive wells, and facilities in Saskatchewan. It is anticipated that this percentage will gradually increase over time, with the 2024 estimate being 6%.

Manitoba

In Manitoba, the Petroleum Branch of the Department of Growth, Enterprise and Trade develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Crude oil and natural gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (the *MBOGA*), *The Oil and Gas Production Tax Act* and related regulations and guidelines. The *Environment Act* establishes the environmental assessment and licensing process for developments in Manitoba for projects which may have the potential to cause significant environmental and / or human health effects. Projects which are defined as developments which must undergo the environmental assessment and licensing process are listed in the *Classes of Development Regulation*.

Liability Management Rating Programs

Alberta

The AER oversees liability management in the province. On June 30, 2020, the Government of Alberta announced a new Liability Management Framework (*AB LMF*) that replaced the Alberta Liability Management Program (*AB LMR Program*) and its constituent programs. The primary goals of the AB LMF are to assist in addressing the Orphan Well Association's (*OWA*) inventory and, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project. Since the announcement, the Government of Alberta has gradually begun to phase-in the AB LMF through legislative and AER directive amendments.

The announcement and implementation of the AB LMF and the desire to rethink liability management in Alberta follows the SCC's decision in *Orphan Well Association v Grant Thornton Ltd.* (also known as the *Redwater decision*). As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licencees or to require a licencee to pay a security deposit before approving a transfer when such a licencee 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 passed Bill 12: *The Liabilities Management Statutes Amendment Act* (the *LMSAA*) which came into force on proclamation. The LMSAA places the burden of a defunct licencees' abandonment and reclamation obligations first on the defunct licencee's working interest partners, and second, the AER may order the orphan fund (the *Orphan Fund*) to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Alberta's OGCA established an Orphan Fund which is run by the OWA to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licencee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be bankrolled exclusively by licencees in the former Licensee Liability Rating Program (the *AB LLR Program*) and Alberta Oilfield Waste Liability Program (the *AB OWL Program*) who contributed to a levy administered by the AER.

However, the Government of Alberta has loaned the Orphan Fund approximately $335 million. The Government also covered $113 million in levy payments that licencees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. Collectively, these programs were designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licencees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. Under the new AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

The AB LMR Program previously governed most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consisted of three distinct programs: the AB LLR Program, the AB OWL Program and/or the Large Facility Liability Management Program.

Following the Redwater decision, Alberta has 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 licencee 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 OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure.

On December 1, 2021, the Government of Alberta announced amendments to Directive 006: *Licensee Liability Rating (LLR) Program* and a new Directive 080: *Licensee Life-Cycle Management* and accompanying Manual 023: *Licensee Life-Cycle Management*. A new Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* was also introduced in April 2021 which introduced new criteria for the AER to consider whether an applicant, licencee or approval holder poses an "unreasonable risk". Among other changes under the AB LMF, the AB LLR 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 AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF provides proactive support to distressed operators and requires companies operating in Alberta's petroleum 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 licencee is required to meet mandatory annual spend targets for well closures and abandonments. During the summer of 2022, the AER announced it would increase spend targets for liabilities in 2023 from $422 million to $700 million and released forecasted targets through 2027, each of which are expected to increase annually by 9%.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary area-based closure (*ABC*) program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets. The ABC, together with the inventory reduction program implemented under the AB LMF, which implements mandatory closure spend targets over a five-year rolling period, will enable companies to work together to share the costs of cleaning up multiple sites in one area.

On November 16, 2023, the AER provided an update on the ongoing implementation of the AB LMF. The process to implement the AB LMF involves updating various regulatory instruments and establishing a new security framework under the OGCA. The changes aim to improve risk assessment, ensure fair responsibility for cleanup in active sites, and streamline regulations. The new security framework will consider factors beyond the LLR, such as the entire energy development life cycle and the polluter-pay principle. Stakeholder engagement is planned for 2024 before releasing draft documents for public comment.

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.

British Columbia

The BC Commission previously oversaw a Liability Management Rating Program (the *BC LMR Program*), which was designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. In the spring of 2019, the BC Commission introduced a Comprehensive Liability Management Plan (*CLMP*). The purpose of the CLMP is 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. In April 2022, the Permittee Capability Assessment Program (*PCA*) was implemented to replace the BC LMR 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 (*OSRF*). In November 2023, British Columbia published the Permittee Capability Assessment Program Guidance. The British Columbia Energy Regulator (*BCER*) is responsible for the PCA which is intended to assist the BCER in the assessment of financial risk of a permit holder's operations in British Columbia while mitigating identifiable risks while permit holders are financially viable. The financial risk of a permit holder is measured as the financial impact on the OSRF.

In the spring of 2019, a liability-based levy paid to the OSRF replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the 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 levy. The ERAA permits the BC Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, the Dormancy and Shutdown Regulation (the *Dormancy Regulation*) established the first set of legally imposed timelines for the restoration of crude 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 currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan. The BC Commission made amendments throughout 2023 to expand the Dormancy and Shutdown Regulation to include pipelines, facilities and related activities.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administers the Licensee Liability Rating Program (the *SK LLR Program*). The SK LLR Program is designed to assess and manage the financial risk that a licencee'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 requires all new licencees to submit a $10,000 non-refundable Orphan Fund fee in order to be deemed eligible to transfer licences, and all licencees whose deemed liabilities exceed their deemed assets (i.e., an LLR below 1.0) are required to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licencees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities and this data is publicly available. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

Manitoba

To date, the Government of Manitoba has not implemented a liability management rating program similar to those found in the other Western Canadian provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the *Drilling and Production Regulations*. The MBOGA also establishes the Abandonment Fund Reserve Account (the *Abandonment Fund*). The Abandonment Fund is a source of funds that may be used to operate or abandon a well or facility when the licencee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred, as well as annual levies for inactive wells and batteries.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's petroleum and natural gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds were administered by regulatory authorities in each province. In Alberta, the Ministry of Energy disbursed its $1 billion share of the federally provided funds through the Site Rehabilitation Program, which is closed to new applicants. The Government of British Columbia disbursed its $120 million share of the federally provided funds through three programs: (i) the Dormant Sites Reclamation Program, which requires all work to be complete by December 31, 2022; (ii) the Orphan Sites Supplemental Reclamation Program; and (iii) the Legacy Sites Reclamation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund. And in early March 2020, the Government of Alberta announced an extension by up to $100 million of an existing $235 million loan to the Orphan Fund. In Saskatchewan, $400 million in federal funding was used for the Accelerated Site Closure Program (*ASCP*). The first phase of the ASCP made $100 million available to eligible service companies to conduct abandonment and reclamation work. In July 2022, the ASCP opened application processes to release all remaining ASCP funding to eligible licensees. The ASCP ended in the spring of 2023.

CLIMATE CHANGE REGULATION

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the petroleum and natural gas industry in Canada. These impacts are uncertain and it is 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 changes 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. On January 20, 2021, President Biden of the United States signed an executive order to rejoin the Paris Agreement. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference, scheduled to take place in November 2021 in Glasgow. The result of The 2021 United Nations Climate Change Conference, more commonly referred to as COP26, was the Glasgow Climate Pact, negotiated through consensus of the representatives of the 197 attending parties. Owing to late interventions from India and China, that weakened a move to end coal power and fossil fuel subsidies, the conference ended with the adoption of a less stringent resolution than some anticipated. The Glasgow Climate Pact reaffirms the long-term global goals (including those in the Paris Agreement) to hold the increase in the global average temperature to below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030; however, they have also indicated that they expect to implement policies to exceed this target. In connection with this target, 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 December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the *HEHE Plan*) which builds on the Pan-Canadian Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes a $3 billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels.

Single-use Plastics Prohibition Regulations

Also of relevance to the petroleum and natural gas industry, in June 2022, the federal government introduced the Single-use Plastics Prohibitions Regulations (*SUPPR*). The SUPPR prohibits, subject to certain exemptions, the manufacture, import and sale of single-use plastic checkout bags, cutlery, foodservice ware made from or containing problematic plastics, ring carriers, stir sticks and straws. The prohibitions on manufacture and import for sale in Canada and sale and manufacture, import and sale for export come into force on a rolling basis between December 2022 and December 2025.

On November 16, 2023, the Federal Court ruled that the categorization of all "Plastic Manufactured Items" (*PMIs*) as Toxic Substances in Schedule 1 of the *Canadian Environmental Protection Act, 1999* (*CEPA*) was both unreasonable and unconstitutional. The Federal Court determined that the Government of Canada lacked sufficient evidence to label all PMIs as toxic, emphasizing that the authority to regulate substances for environmental protection only applies to those listed as toxic under CEPA. The federal government has indicated it plans to appeal this decision. Despite the SUPPR remaining in effect, the direct challenge brought by Petro Plastics Corp., RPUC and Oregon Precision Industries has been temporarily halted pending the resolution of the decision regarding the PMI designation under CEPA. With the recent issuance of the decision by the Federal Court, the challenge against the SUPPR will likely continue in 2024.

Canadian Net-Zero Emissions Accountability Act

On November 19, 2020, the federal government announced Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero GHG 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.

Greenhouse Gas Pollution Pricing Act

On June 21, 2018, the federal government enacted the GGPPA, which came into force on January 1, 2019. This regime has two parts: the OBPS and a regulatory fuel charge (the *Fuel Charge*) imposing an initial price of \$20/tonne of CO_2e. 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 HEHE Plan, the price on carbon is set to increase annually at a rate of \$15/tonne of CO_2e 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.

Alberta, Saskatchewan, Ontario and Manitoba each challenged the constitutionality of the GGPPA. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the SCC and the hearing took place in September 2020. On March 25, 2021, the SCC released its decision in *Reference re Greenhouse Gas Pollution Pricing Act*, upholding the constitutionality of a federal law establishing minimum national standards for carbon pricing in Canada.

Manitoba also made an appeal to the Federal Court stating the federal government did not act properly in imposing a minimum price on carbon because Manitoba was planning to use its own lower price. In October 2021, the Federal Court rejected Manitoba's argument stating the federal government's actions were consistent with the purpose of the GGPPA as was upheld by the SCC.

Following the SCC's decision upholding the constitutionality of the GGPPA, any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards or federal benchmarks. Currently the provincial systems, together with the Fuel Charge apply in each of Alberta, Saskatchewan, Ontario, New Brunswick, Nova Scotia and Newfoundland and Labrador. The provincial plans in each of British Columbia, Québec and the Northwest Territories apply in full in those jurisdictions while the OBPS and Fuel Charge apply in each of Yukon, Nunavut, Manitoba and Prince Edward Island. 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.

Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds

On October 29, 2020, the federal government launched the $750 million Emission Reduction Fund to reduce methane and GHG emissions. The fund will provide repayable funding to eligible onshore and offshore crude oil and natural gas companies to support investments to reduce GHG emissions by adopting greener technologies. Part of this fund is directed towards methane reduction.

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 petroleum and natural gas industry, 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 the 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 natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

On December 4, 2023, the Minister of Environment and Climate Change announced amendments to the Federal Methane Regulations that seek to further cut emissions. These amendments closely mirror those in the United States and echo the International Energy Agency's call to curtail methane emissions from the oil and gas sector by 75% by 2030. These amendments signify a significant reinforcement to Canada's methane strategy. The draft amendments are undergoing consultation until mid-February 2024. The Government of Alberta has opposed the amendments, stating it will take measures to ensure the amended regulations are not implemented in Alberta. It is unknown at this time what the potential effects of the amended Federal Methane Regulations may be.

Clean Fuel Regulations

The federal government has also announced that it will proceed with the development and implementation of a *Clean Fuel Standard* (*CFS*) that will require producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. On December 18, 2020, the federal government published proposed *Clean Fuel Regulations* (*CF Regulations*) which came into force on June 21, 2022, which implements the CFS. The CF Regulations take a performance-based approach to reducing greenhouse gas emissions. The CF 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 will start at 3.5 gCO_2e/MJ, increasing by 1.5 gCO_2e/MJ each year and reaching 14 gCO_2e/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 CF Regulations offer compliance credits, tracked via the Credit and Tracking System, and create a credit market to incentivize industries to innovate and adopt cleaner technologies to lower their compliance costs.

Clean Electricity Regulation

On August 10, 2023, the federal government released a draft of the *Clean Electricity Regulations* which will help drive progress towards a net-zero electricity grid by 2035. The *Clean Electricity Regulations* are part of a suite of measures by the Government of Canada from the 2030 Emissions Reduction Plan to transition to clean energy. Developed under CEPA, these regulations establish stringent pollution emission standards without prescribing specific technologies. This technology-neutral stance aims to grant flexibility to provincial, territorial, and municipal authorities as they transition to clean energy.

The Alberta Government has contested the constitutionality of the draft *Clean Electricity Regulations* and urged the federal government to support Alberta's plan for achieving carbon neutrality by 2050. On November 27, 2023, the Government of Alberta issued notice of its intention to invoke a resolution under the *Alberta Sovereignty within a United Canada Act* (the *Sovereignty Act*) in response to the draft *Clean Electricity Regulations*. This resolution directs specific provincial entities from enforcing or complying with the *Clean Electricity Regulations* "to the extent legally permissible." Similarly, the Government of Saskatchewan plans to utilize *The Saskatchewan First Act* to establish a tribunal to assess the economic impacts of the *Clean Electricity Regulations*. Consequently, there is a strong possibility that once implemented, the *Clean Electricity Regulations* will face constitutional challenges.

Air Pollutant Regulations

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

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

Framework to Phase Out Fossil Fuels

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.

Bill S-5 - Recognizing the Right to a Healthy Environment

On June 13, 2023, Bill S-5 *Strengthening Environmental Protection for a Healthier Canada Act* to amend CEPA, received royal assent. The amendments include changes to the preamble of CEPA, which now recognizes that every individual in Canada has a right to a healthy environment. Section 2 of CEPA now requires that the federal government protect this right, and that an implementation framework be developed to consider how this right will be administered under CEPA, which is anticipated to be published by 2025. Further amendments include creating a risk assessment Plan of Chemical Management Priorities, setting out a multi-year assessment of substances and activities, and a commitment to consider the cumulative effects of these assessments on vulnerable populations.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the *CLP*). Under this strategy, the *Climate Leadership Act* (Alberta) (the *CLA*) came into force on January 1, 2017 and established a fuel charge that was compliant with federal requirements. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites.

In June 2019, the Government of Alberta repealed the CLA and the Fuel Charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $65/tonne of CO_2e and will increase to $80/tonne on April 1, 2024. 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 provisions of the TIER regulation required that an interim review of the regulation be completed by December 31, 2022 giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of the carbon pricing systems for 2023 to 2030. Following the comment period, the *Technology Innovation and Emissions Amendment Regulation* was adopted with certain amendments to the TIER regulation becoming effective January 1, 2023. These amendments include, among others, meeting the federal standards for Alberta's carbon pricing system, the creation of sequestration credits for carbon capture, utilization and storage (*CCUS*) projects and amendments to the number of credits that can be used to meet emission targets. The TIER regulation is set to undergo another review by December 31, 2026.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high-performance benchmarks. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that they do not meet the 100,000 tonne threshold. The amendments reduced the threshold for those to opt-in from 10,000 tonnes of CO_2e to 2,000 tonnes of CO_2e per year. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta. As discussed above, 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. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the *Alberta Methane Regulations*) on January 1, 2020 and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating and Venting* (*Directive 060*). The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* (*Directive 017*) that took effect in December 2018. In November 2023, it was announced that Alberta had achieved its goal of reducing methane emissions by 45% by 2025, years ahead of schedule.

In May 2020, the Government of Canada and the Government of Alberta announced a preliminary equivalency agreement (*Equivalency Agreement*) regarding the reduction of methane emissions. Through the Equivalency Agreement and Directive 060 and Directive 017, Alberta maintains jurisdiction over the regulation of the upstream oil and gas industry. Should amendments to the Federal Methane Regulation 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.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement CCUS technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale CCUS projects. Both projects will help reduce the CO_2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment* Act*, 2010*. It deemed the pore space underlying all land in Alberta to be and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies have begun exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest $40 million in 11 CCUS hub projects through Emissions Reduction Alberta.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap. Hydrogen is positioned to play a significant role in the de-carbonization of the global economy and Alberta has significant opportunity to play a major role both nationally and internationally. The Hydrogen Roadmap is divided into two phases. The first phase focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization. The AUC also released its Hydrogen Inquiry Report in September 2022 which reviewed the viability and impacts of hydrogen blending into natural gas distribution systems in Alberta.

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.

On August 3, 2023, the Alberta Ministry of Affordability and Utilities announced that the AUC was directed to pause approvals of new renewable electricity generation projects until February 29, 2024. The announcement was in response to the need to review and consider policy changes in relation to renewable development. The review of the polices for renewable resource development will include a public inquiry, after which the AUC must submit a report on the findings no later than March 29, 2024 to the Minister of Affordability and Utilities. It is unknown at this time what effect the renewable pause and corresponding inquiry may have on the energy market in Alberta.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims 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.

On January 1, 2016, the *Greenhouse Gas Industrial Reporting and Control Act* (the *GGIRCA*) came into effect, which streamlined the regulatory process for large emitting facilities. 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. British Columbia was the first Canadian province to implement a revenue-neutral fuel charge.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "CleanBC", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030 (the *Clean BC Plan*). The CleanBC Plan includes a number of strategies targeting the industrial, transportation construction and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of crude oil and natural gas production; (v) reducing 45% of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles. To further these initiatives, CleanBC released a CleanBC Roadmap, outlining it's plan to achieve its emission target, while building a cleaner economy across eight pathways which includes the oil and gas industry.

In 2021, British Columbia released a strengthened clean energy plan, 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. In fulfilling its commitment, the Government of British Columbia undertook a review on carbon pricing in the province, seeking feedback from certain stakeholders as to how to best align its carbon pricing regime with the federal carbon pricing rules.

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 CO_2e and would increase by $15/tonne each year until it reaches $170/tonne in 2030. As of April 1, 2024, British Columbia's carbon tax shall increase to $80/tonne of CO_2e. It was also announced that commencing in April 2024, British Columbia's system will switch to a new made-in-B.C. output-based pricing system (*BC OBPS*). The BC OBPS shall apply 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 will be mandatory for certain industrial producers under the GGIRCA, that emit above 10,000 tonnes of CO_2e per year and will exclude 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 CO_2e per year. In order to support the new BC OBPS, the CleanBC Industry Fund is currently undergoing certain transitions to align with the new BC OBPS and is expected to launch in Spring 2024.

On July 6, 2021, the Government of British Columbia released the B.C. Hydrogen Strategy, which lays out a framework for the province to utilize hydrogen in support of its 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).

On January 16, 2019, the BC Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020. 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 will be in place for a period of five years.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the *MRGGA*) to regulate 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. The Government of Saskatchewan subsequently 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 and 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 on December 18, 2018, establishing the framework of an output-based emissions management framework. In November 2022, the province of Saskatchewan received confirmation that a provincial plan has been approved to replace the federally imposed carbon tax on industrial emitters effective as of January 1, 2023. The Saskatchewan OBPS meets the federal stringency requirements and regulated emitters will receive credit for every tonne of CO_2e under their permitted amount. The OBPS program in Saskatchewan includes credits for emitters utilizing CCUS technologies at their facilities. As noted above, the Fuel Charge applies in Saskatchewan.

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 licencees of oil facilities that may generate more than 50,000 tonnes of CO_2e per year, obliging each licencee 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 reduce 4.5 million tonnes of CO_2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO_2e by 2030.

On April 10, 2019, Saskatchewan produced its 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.

In October 2019, *The Oil and Gas Conservation Amendment Act* was proclaimed into force, which 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 November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply. The equivalency agreement terminates on or by December 31, 2024.

Manitoba

In 2018, the Government of Manitoba unveiled the *Climate and Green Plan Implementation Act* (the *Implementation Act*). The Implementation Act included a new *Climate and Green Plan Act*, a new *Industrial Greenhouse-Gas Emissions Control and Reporting Act* and various related amendments to existing legislation. Initially, the *Climate and Green Plan Act* introduced a charge of $25/tonne of CO2e on GHG emissions, but this was subsequently withdrawn from the legislation and the federal GGPPA applied in Manitoba. However, in March 2020, the Government of Manitoba introduced the *Climate and Green Plan Implementation Act, 2020*, which, among other things, reintroduces the $25/tonne charge.

Following Manitoba's challenge in the Federal Court, it was determined that the federal government's fuel charge will backstop Manitoba's system because Manitoba's pricing regime is not stringent enough. The

$25/tonne imposed by the *Climate and Green Plan Implementation Act, 2020* does not match increases in the federal benchmark and therefore is not a comparable system. The federal system under the GGPPA therefore applies in full in Manitoba.

The original *Climate and Green Plan Implementation Act* also required the Government of Manitoba to establish five-year emissions reduction targets. In June 2019, the Government of Manitoba announced a GHG emissions reduction target of one megatonne for the 2018-2022 period. The Manitoba Government set the reduction target for the second five year period (2023 to 2027) at 5.6 megatonnes of CO_2e emulative emissions reductions.

ACCOUNTABILITY AND TRANSPARENCY

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the *ESTMA*) came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including Indigenous groups), including royalty payments, taxes (other than consumption taxes and personal taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

Bill S-211, *An Act to enact the Fighting Against Forced Child Labour in Supply Chains Act and to amend the Customs Tariff* (the *Modern Slavery Act*) received royal assent on May 11, 2023 and came into force on January 1, 2024. Pursuant to the Modern Slavery Act, entities that meet certain criteria are required to file public reports annually on the steps they have taken prevent and reduce the use of forced labour and child labour in their supply chains. Corporations that meet the requirement to comply with the obligations under the Modern Slavery Act will be required to submit their first annual report by May 31, 2024. The Company will be required to comply with the reporting obligations under the Modern Slavery Act and is preparing its first report. See "*Risk Factors – Evolving Corporate Governance, Sustainability and Reporting Framework*".

INDIGENOUS RIGHTS

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and natural gas industry. In addition, Canada is a signatory to the *United Nations Declaration of the Rights of Indigenous Peoples Act* (*UNDRIP*) and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and natural gas industry in Western Canada. On November 28, 2019, the *Declaration on the Rights of Indigenous Peoples Act* (the *DRIPA*) became law in British Columbia. The Government of British Columbia released an interim approach in furtherance of its implementation of DRIPA which outlines a process for how new policy and legislation in the province are to be aligned with the UNDRIP. The action plan is the first of its kind to be enacted by any province and it is uncertain as to what potential consequences the implementation of the plan and its effects on future legislative drafting.

Similar to British Columbia's DRIPA, the UNDRIP requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and natural gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The federal government has expressed that implementation of the UNDRIP has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that, subject to the forthcoming opinion from the SCC, the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in *Yahey v British Columbia* (the *Blueberry Decision*), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation (*BRFN*) in Northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. Going forward, the Blueberry Decision may have significant impacts on the regulation of industrial activities in Northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties.

On October 7, 2021, the Government of British Columbia and the BRFN reached an initial agreement in response to the Blueberry Decision in which the parties agreed to negotiate a land management process for BRFN territory, and certain previously authorized forestry and oil and gas projects were put on hold pending further negotiation. Currently, the Government of British Columbia and the BRFN are in the midst of negotiations to finalize a new regime for assessment, authorization and management of industrial activities on BRFN territory in a manner consistent with the Blueberry Decision. The BRFN elected a new Chief in January 2022. The long-term impacts and risks of the Blueberry Decision and the election of a new BRFN Chief on the Canadian oil and natural gas industry remain uncertain.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nation Implementation Agreement (*Implementation Agreement*). The Implementation Agreement marks a significant shift in how the Province and First Nations will jointly manage land, water, and resources. It focuses on cumulative effects within the BRFN's claim area by initiating land restoration efforts, establish protected zones to safeguard against development, and imposes restrictions on development activities. All of the goals will be carried out through a series of measures, including a $200 million restoration fund by June 2025, limits on new petroleum and natural gas development and a new planning regime for future oil and gas activities. At the outset, the BRFN received $87.5 million as a financial package over three years, with potential for greater benefits tied to petroleum and natural gas revenue sharing and provincial royalty revenues in the coming two financial years.

On January 20, 2023, the Government of British Columbia also finalized a co-developed set of initiatives (*Consensus Document*) with four other Treaty 8 First Nations, including the Fort Nelson, Saulteau, Halfway River and Doig River First Nations (*Treaty 8 Nations*). Both the Implementation Agreement and the Consensus Document respond to the Blueberry Decision. The precedent established by the Implementation Agreement and the Consensus Document may extend beyond Treaty 8 territory and may have implications for resource development in British Columbia, Alberta and Canada at large.

The key elements of the Implementation Agreement are:

Wildlife Management: The Government of British Columbia and BRFN are committing to bring together Indigenous knowledge and western science. Both parties will support a community stewardship, monitoring and guardian program. Further, important species will be closely monitored.

Land-Use Plans: The Government of British Columbia and BRFN will engage in collaborative land-use planning to determine whether certain activities can occur in Treaty 8 territory. Collaborative land-use planning includes a commitment to advance watershed-level land use plans within the next three years (*Watershed Management Basin Plans*).

Petroleum and Natural Gas: The Government of British Columbia and BRFN will use a more collaborative approach to oil and natural gas development planning and projects. The Government of British Columbia, various companies and other First Nations will sit together and address: the establishment of areas for permanent protection; minimizing disturbance from petroleum and natural gas development; reducing new disturbance from petroleum and natural gas by approximately 50 percent from pre-Blueberry Decision years; introducing operational and strategic planning expectations for the sector; and limiting overall new disturbances from petroleum and natural gas activities in BRFN's claim area.

Forestry: The Government of British Columbia and BRFN will protect old growth forest and reduce timber harvesting in defined high value areas. Key elements of the Implementation Agreement applicable to forestry include: a cessation to aerial herbicide use; a commitment to implementing ecosystem-based management through Watershed Management Basin Plans; and a two-year harvest schedule outside the BRFN's important forestry areas.

Honoring Treaty 8: The Government of British Columbia and BRFN have agreed to work together on measures to honor Treaty 8, including improving awareness and education on Treaty 8. The Government of British Columbia and BRFN will honor Treaty 8 by sustaining communications, sharing training and awareness building, and providing support for communications with other Treaty 8 First Nations and local elected elders.

The Implementation Agreement also includes establishing a $200 million restoration fund by June 2025, which is meant to support the restoration of land from industrial disturbance. Further, BRFN will receive $87.5 million as a financial package, with an opportunity for increased benefits based on petroleum and natural gas revenue-sharing and provincial royalty revenues in the next two years.

According to the Government of British Columbia, the Consensus Document will address the cumulative impacts of industrial development on the meaningful exercise of Treaty 8 rights in the territory, restore land and produce stability and predictability for industry in the region, and promote responsible resource development and sustainable economic growth in Treaty 8 territory. Further, it aims to manage the impacts of industrial development through ecosystem-based stewardship and governance. The Consensus Document set out various initiatives to outline how the Government of British Columbia and Treaty 8 Nations manage the land to achieve sustainability for future generations, meet the Crown's obligations to uphold constitutionally protected rights and support responsible resource development and economic activity in northeastern British Columbia. Specifically, the initiatives outlined in the Consensus Document include: (i) a new approach to wildlife co-management; (ii) new land-use plans and protection measures; (iii) a "cumulative effects" management system; (iv) pilot projects to advance shared decision-making for environmental planning and stewardship; (v) a multi-year, shared restoration fund; (vi) a new revenue-sharing approach to support the priorities of Treaty 8 First Nation communities; and (vii) actions to promote education about Treaty 8 through collaborative promotion, anti-racism training and awareness building.

In April 2023, the Government of British Columbia and the federal government reached an agreement with the Treaty 8 First Nations, pursuant to which the Government of British Columbia will make available 109,385 acres to the nations and the federal government will give $800 million to honour the Treaty 8 Nations. Relatedly, the Government of Alberta also agreed to give an amount of land to the Doig River First Nation in a related agreement.

While it is expected that the Implementation Agreement and Consensus Document will create additional consultation and regulatory obligations for operators seeking to develop natural resources in the affected region, the extent of such obligations remain to be seen.

In July 2022, the Duncan's First Nation in Northern Alberta filed a lawsuit claiming cumulative effects from industry, agriculture and settlement which violate their treaty rights. The claim advances many of the same grounds as those that were the subject of the Blueberry Decision and as of the date of this AIF, is still making its way through the judicial process.

As of the date of this AIF, the full texts of the Implementation Agreement and the Consensus Document have not been made publicly available. While it is expected that the Blueberry Decision, the Implementation Agreement and the Consensus Document will have an impact on consultation and regulatory obligations for operators seeking to develop natural resources in affected areas in other provinces, the extent of such obligations and the long-term impacts and risks of the Blueberry Decision, and any subsequent decisions, on the Canadian oil and natural gas industry remain uncertain.

Risk Factors

The Company is subject to both risks that directly affect its business and operations, as well as indirect risks that impact third parties or industry generally. Investors should carefully consider the risk factors set out below and consider all other information contained herein, and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business, the business of third parties with whom the Company conducts business and the crude oil and natural gas business generally.

Although the Company does not directly conduct operations but instead collects royalty payments in respect of the Royalty Properties resulting from the development of such properties, its business and financial condition are linked to the risks that impact the petroleum and natural gas industry generally and in particular those which affect the lessees and/or operators that have or will have arrangements with the Company in respect of the Royalty Properties. Accordingly, where applicable, the following risk factors should be read in the context of both their direct and indirect (through such lessees and/or operators) impact on the Company's business and financial condition.

Dependence on Lessees and/or Operators

The Company is dependent on lessees and/or operators of the Royalty Properties.

Third-party exploration and production companies are the lessees and/or operators of the Royalty Properties. The Company has limited to no ability to exercise influence over the operations on the Royalty Properties or the associated operating or capital costs, which could adversely affect the Company's financial performance, which adverse effect could prove to be material over time. The Company's revenues, which are derived from the Royalty Properties operated by third parties, depend upon a number of factors, most of which are outside of the Company's control. Such factors include: the extent of exploration on and development of the Royalty Properties; the timing and amount of capital expenditures on those properties; the operator's expertise, production practices and financial resources; the approval of other participants; the selection of technology and cost; risk management; compliance by third party lessees and/or operators with licence or lease terms relating to the Royalty Properties; and environmental compliance and remediation practices.

While the Company actively pursues additional leasing and royalty arrangements with lessees and/or operators, there is no guarantee that the Company will be successful in securing such third parties for all or the majority of the Royalty Properties. Further, for Royalty Properties or formations that are not held by production at the end of the primary term, there can be no assurance that the Company will be able to re-lease such properties or formations or, if it is able to re-lease such properties or formations, that the lease terms and rates will be as favourable to the Company.

The third-party exploration and production companies involved with the Royalty Properties may manage or participate in a wide variety of projects in the conduct of their business, which may result in such third parties diverting capital, development activity and expertise away from the Royalty Properties. In addition, third party exploration and production companies involved in the Royalty Properties may defer or cancel capital projects in a low commodity price environment. The deferral or cancellation of development or capital projects conducted on the Royalty Properties may delay or reduce expected revenues from operations conducted by third parties on the Royalty Properties, which, in turn, would result in a reduction of the Company's revenues. The ability of these third parties to execute projects and market crude oil and natural gas from the Royalty Properties depends upon numerous factors beyond such third parties' and the Company's control, including the risk factors set out below. Because of these factors, these third parties could be unable to execute projects on the Royalty Properties on time, on budget, or at all, and may be unable to produce and market the crude oil and natural gas from the Royalty Properties effectively, all of which would result in a reduction of the Company's associated revenues.

In addition, due to volatile commodity prices, many companies, including companies that are lessees on the Fee Lands or working interest owners on the Royalty Properties, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. The SCC's decision in *Redwater* may give rise to new covenants and restrictions under a lessee or working interest owner's credit facilities, and due to the holistic nature of the AB LMF, the regulator may now consider additional financial considerations and liabilities which may impact the ability to complete asset dispositions and acquisitions. These lessees or working interest owners may also be required to provide additional reporting to their lenders regarding existing and/or budgeted abandonment and reclamation obligations, decommissioning expenses, liability management rating and/or any notices or orders received from an energy regulator in any applicable province. In cases where a lessee or working interest owner's credit facilities are dependent on a borrowing base, lenders may also be permitted to re-determine the borrowing base following a decline in the lessee or working interest owner's liability management rating below a certain threshold or, if the lessee or working interest owner becomes subject to an abandonment and reclamation order and its estimated cost of compliance with such order exceeds a certain threshold. The holistic assessment to liability management implemented under the AB LMF also permits a more comprehensive review of financial health of an applicant, licencee or approval holder in a determination as to whether or not such corporation or individual poses an "unreasonable risk" and may impose increased financial disclosure obligations.

Continued volatile commodity prices may also result in companies choosing to defer capital spending or shutting-in existing production. Any reduction in the drilling and production from lands in which the Company has a royalty interest will negatively affect the Company's cash flows and financial results.

Further, any financial difficulty of companies who are lessees on the Fee Lands or working interest owners on the Royalty Properties may affect the Company's ability to collect royalty payments especially if such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy, insolvency or creditor protection. See "*Risk Factors – Third Party Credit Risk*".

Prices, Markets and Marketing

Various factors may adversely impact the marketability of crude oil and natural gas, affecting net royalty production revenue, royalty production volumes and development and exploration activities on the Royalty Properties.

The ability to market crude oil and natural gas from the Royalty Properties may depend upon the ability of third-party operators to acquire capacity in pipelines that deliver oil, NGL and natural gas to commercial markets or contract for the delivery of crude oil and NGL by rail (see "*Industry Conditions – Pricing and Marketing in Canada – Petroleum and Natural Gas Industry*" and "*Risk Factors – Weakness and Volatility in the Petroleum and Natural Gas Industry*"). Numerous factors beyond the Company's control do, and will continue to, affect the marketability and price of crude oil and natural gas acquired, produced, or discovered on, the Royalty Properties:

- deliverability uncertainties related to the distance the reserves on the Royalty Properties are from pipelines, railway lines, and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and
- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of crude oil and natural gas.

Crude oil and natural gas prices 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, the war in Ukraine 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. A material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of the Company's anticipated royalty production revenue associated with the Royalty Properties. The economics of producing from some wells may change because of lower prices, which could result in reduced production of petroleum or natural gas and a reduction in the volumes of the reserves associated with the Royalty Properties. Lessees on the Royalty Properties may also elect, pursuant to the terms of the leases, during the primary term not to produce from certain wells at lower prices, which, in turn, would reduce the Company's royalty production revenues. Any substantial and extended decline in or continued low crude oil and natural gas prices would have an adverse effect on the third-party operators of the Royalty Properties and may impact the Company's carrying value of its reserves, royalty revenues, profitability and cash flow which may have a material adverse effect on the Company's business and financial condition. See "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Petroleum and Natural Gas Industry*".

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.

Third Party Exploration, Development and Production Risks

The Company's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of crude oil and natural gas.

Crude 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 enter into lease and royalty arrangements with exploration and production companies and promote the exploration for and development and commercial production of crude oil and natural gas on the Company's properties by these lessees, as well as to acquire additional crude oil and natural gas assets to contribute to additional crude oil, natural gas and NGL reserves. A future increase in the Company's reserves will also depend on the ability of the Company to encourage further exploration on and development of the Royalty Properties by third parties. Without the continual addition of new reserves, the Company's reserves and related royalty revenue stream will decline over time as the lessees produce from such reserves. There is no assurance that the Company will be able to continue to find satisfactory third-party exploration and production companies to participate on the Royalty Properties or to otherwise acquire additional crude oil and natural gas assets to contribute additional reserves. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that these lessees will discover or acquire further commercial quantities of crude oil and natural gas.

Future crude oil and natural gas exploration on the Royalty Properties may involve unprofitable efforts from dry wells or wells that are productive but do not produce sufficient petroleum substances to return a profit to a third party 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, which may result in decreased activities on the Royalty Properties by third parties and therefore less revenue to the Company.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations of third parties on the Royalty Properties and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and the shutting-in 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 oil 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 a third party's production from the Royalty Properties, which may reduce the Company's revenue.

Crude 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. These typical risks and hazards could result in substantial damage to crude oil and natural gas wells, production facilities, other property, the environment and cause personal injury or threaten wildlife. Particularly, operators on the Royalty Properties may explore for and produce sour natural gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the third parties on the Royalty Properties, which, in turn, may result in liability to the Company.

Crude oil and natural gas production operations are also subject to geological and seismic risks including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a negative effect on production from the Royalty Properties, which negative effect could prove to be material over time and which may reduce the Company's revenue.

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 in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Company could incur significant costs. See "*Risk Factors – Insurance*".

Political Uncertainty

The Company's business may be materially adversely affected by recent political and social events and decisions made in the United States, Europe and elsewhere.

In the last several years, the United States, the Middle East and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership (*TPP*) and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces United States corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The United States has not indicated any intention to rejoin the TPP but could try to negotiate stronger labour and environmental standards. The United States will be subject to a presidential election in the fall of 2024 which may lead to a change in administration which could have an impact on the current political agenda and policies of the United States.

Additionally, on January 20, 2021, the Biden administration announced its decision to revoke the federal permit granted by the former administration for the Keystone XL Pipeline, which overturned a comprehensive regulatory process that lasted more than a decade. In addition, NAFTA has been replaced with the USMCA. This has affected the competitiveness of other jurisdictions, including Canada. On January 25, 2021, the Biden administration signed an executive order with respect to stringent new Made-In-America rules for the U.S. government and has indicated that the exceptions to such rules will be very limited. The effects on the USMCA and the Canada-U.S. supply chain have not yet been significant but future potential impacts are unknown.

Further, it is unclear exactly what other actions the United States administration, or incoming administration, will implement, and if implemented, how these actions may impact Canada and in particular the petroleum and natural gas industry. Any actions taken by the current United States administration may have a negative impact on the Canadian economy and on the businesses, financial condition, results of operations, prospects and the valuation of Canadian crude oil and natural gas companies, which could also negatively impact the Company, which negative impact could prove to be material over time.

In addition to the political disruption in the United States, the long-term impacts of the United Kingdom's exit from the European Union remain unforeseen, especially in a post-pandemic era. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East, including the ongoing military conflict in Israel, the West Bank and Gaza Strip, Yemen and the Red Sea and Yemen. To the extent that certain political actions taken in North America, Europe, the Middle East and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, costs for goods and services required for the Company's business could increase and access to skilled labour could decrease, negatively impacting the Company's business, financial condition, results of operations, prospects and the market value of its Common Shares, which negative impact could prove to be material over time.

Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tension in Eastern Europe. In February 2022, Russia sent troops into pro-Russian separatist regions in Ukraine, which has resulted in continued and ongoing conflict in Ukraine to date. Ongoing military tensions between Russia and Ukraine have the potential to threaten supply of oil and gas from the region and impact demand from other European countries as well as the possibility that other nations will impose certain tariffs and restrictions on oil from Russia. The long-term impacts of the tension between Russia and the Ukraine remains unclear, including the responses from other nations globally.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the petroleum and natural gas industry including the balance between economic development and environmental policy. In January 2020, the SCC unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, tensions remain between provincial and federal governments. Continued uncertainty and delays, including a temporary shutdown due to flooding in British Columbia and wildfires in Alberta have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdictions where the Royalty Properties are located.

Following former Alberta Premier Jason Kenney's resignation on May 18, 2022, Danielle Smith was elected as Premier on October 11, 2022. Shortly after her appointment, Premier Smith introduced Bill 1: *The Alberta Sovereignty Within a United Canada Act (*the *Sovereignty Act*). The Sovereignty Act was passed on December 8, 2022 and received Royal Assent on December 15, 2022. The Sovereignty Act, amongst other things, enables the Alberta Government to choose which federal legislation, policies or programs it will enforce in Alberta, providing an overriding right to not enforce those which the Alberta Government deems to be "harmful" to Alberta's interests or infringe on the Federal Constitution and its division of powers. The Sovereignty Act has been opposed by many, including the National Democratic Party and various Indigenous groups who have expressed concern as to how the Sovereignty Act will affect Indigenous rights and consultation obligations in Alberta. In November 2023, the Government of Alberta introduced a resolution to invoke the Sovereignty Act to challenge the federal government's requirement for a net-zero electricity grid by 2035. It is unclear what the effect the Sovereignty Act will have on Alberta, including the petroleum and natural gas industry, Alberta businesses and its federal and interprovincial relationships, particularly in-light of its recent use, and what impact it may have on the application of other federal legislation in Alberta, such as the GGPPA and the way in which the Alberta Government may address any legislative and policy gaps created. Although the Sovereignty Act has not yet been challenged in court, particularly following its recent application, it is possible the Sovereignty Act's constitutionality will be challenged.

The federal government was re-elected in 2019, but in a minority position. Another federal election was held on September 20, 2021 and the federal government was re-elected again in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the petroleum and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry, which effect could prove to be material over time. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access – Specific Pipeline and Proposed LNG Export Terminal Updates – Curtailment*", and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

Global Financial Markets

The Company's business may be materially adversely affected by ongoing financial conditions and market events.

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 OPEC+, the ongoing risks facing 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.

Sustainable Credit Facility Arrangements

Failing to comply with covenants under the Sustainable Credit Facility could result in restricted access to additional capital or being required to repay all amounts owing thereunder.

The Company is required to comply with covenants under its Sustainable Credit Facility which include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Additionally, sustainability performance criteria have been incorporated into the Sustainable Credit Facility which provides that the Company may incur positive or negative pricing adjustments on drawn and undrawn balances based on changes to the management score measured annually by Sustainalytics. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with any of the covenants could result in an event of default which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the Sustainable Credit Facility and may prevent dividends from being paid to shareholders. The acceleration of the Company's indebtedness under the Sustainable Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Sustainable Credit Facility will impose certain operating and financial restrictions on the Company that include restrictions on the payment of dividends, limitations on liens, entering into disposition of assets or amalgamations and restrictions on speculative hedging, among others. Even if the Company is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Company.

If the Company's lenders require repayment of all or a portion of the amounts outstanding under the Sustainable Credit Facility for any reason, including for a default of a covenant, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under the Sustainable Credit Facility, it may not be on commercially reasonable terms or terms that are acceptable to the Company. Failure to comply with debt covenants or negotiate relief, may result in the Company's indebtedness under the Sustainable Credit Facility becoming immediately due and payable, which may have a material adverse effect on the Company's business and financial condition.

Inflation and Cost Management

Third-party operations on the Royalty Properties may be negatively impacted by inflationary pressures resulting in operational delays, cost overruns and reduced drilling activity on the Royalty Properties.

Third party production companies' 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, which may reduce the Company's revenue. Third party production companies' inability to manage costs may impact project returns and future development decisions, which, in turn, could have a material adverse effect on the Company's business and financial condition.

The cost or availability of oil and natural gas field equipment may adversely affect third party production companies' ability to undertake exploration, development and construction projects. The oil and natural 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 by third-party production companies to secure the services and equipment necessary to their operations on the Royalty Properties for the expected price, on the expected timeline, or at all, may have a material adverse effect on the Company's business and financial condition.

Weakness and Volatility in the Petroleum and Natural Gas Industry

Weakness and volatility in the market conditions for the petroleum and natural gas industry may affect the value of the reserves on the Royalty Properties and restrict lessee and third-party operator cash flow and their ability to access capital to fund the development of the Royalty Properties, which may affect the Company.

Market events and conditions, including global excess crude oil and natural gas supply, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, Russia and the Ukraine, the Middle East, Israel and the West Bank and Gaza Strip, and Yemen; slowing growth in China and emerging economies; market volatility and disruptions in Asia; weakening global relationships; conflict between the United States and Iran; isolationist and punitive trade policies; increased United States shale production; sovereign debt levels; world health emergencies (including the outbreak of pandemic or contagious diseases, such as COVID-19); climate change concerns and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant weakness and volatility in commodity prices. Following extreme supply/demand imbalance in 2020, the crude oil and natural gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. However, the ongoing war in the Ukraine and price caps and sanctions on oil from Russia have impacted demand and oil prices throughout the latter half of 2022 which continued throughout 2023. It is anticipated that the petroleum and natural gas industry will experience more pressure from investors to take meaningful strides towards combating climate change in the upcoming years, including diversifying their energy portfolios. These events and conditions have caused a significant decrease in the valuation of crude oil and natural gas companies and a decrease in confidence in the petroleum and natural gas industry. Such 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 petroleum and natural gas industry in Western Canada and cross-border with the United States has 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 created uncertainty and reduced confidence in the petroleum and natural gas industry in Western Canada. See "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of the Company's reserves rendering certain reserves uneconomic for development by lessees on the Fee Lands and operators and working interest owners on the Royalty Properties. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, lessees and working interest owners' cash flow resulting in reduced capital expenditure budgets and in turn, adversely affecting the royalty revenue received by the Company. The third parties operating on the Royalty Properties may not be able to replace their production with additional reserves which may result in the Company's production and reserves being reduced on a year over year basis. In addition to possibly resulting in a decrease in the value of the economically recoverable reserves from the Royalty Properties, lower commodity prices may also result in a decrease in the value of the infrastructure and processing facilities on such Royalty Properties, all of which could also have the effect of requiring a write down of the carrying value of the Company's crude oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and/or highly dilutive terms.

Project Risks

The success of third-party operations on the Royalty Properties may be negatively impacted by factors outside of the third-party operators' or the Company's control resulting in operational delays and cost overruns.

Third-party operators manage a variety of small and large projects on the Royalty Properties. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The ability of third-party operators to execute projects on the Royalty Properties and to successfully market crude oil and natural gas depends upon numerous factors beyond the third-party operator's or the Company's control, including:

- availability of processing capacity;
- 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 or the third-party operator'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 and severe weather events and natural disasters, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- political uncertainty;
- availability and productivity of skilled labour;
- environmental and Indigenous activism or land claims that potentially result in delays or cancellations of projects;
- litigation and judicial interpretation and application of laws, including with respect to Indigenous rights and historical treaties; and

- regulation of the petroleum and natural gas industry by various levels of government and governmental agencies.

If cash flow from operating activities and funds from external financing sources are not sufficient to cover a third-party operator's capital expenditure requirements, third-party operators may be required to reallocate available capital among their projects or modify their capital expenditure plans, which may result in delays to, or cancellation of, certain projects or deferral of certain capital expenditures. Any change to a third-party operator's capital expenditure plans could, in turn, have a material adverse effect on their growth objectives and business, financial position and results of operations. Because of these factors, third-party operators could be unable to execute projects on time, on budget, or at all which could negatively impact the Company's royalty production volumes and future development activity on the Royalty Properties, which negative impact could prove to be material over time.

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel could negatively impact the Company's operations.

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 which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

There is competition for qualified personnel in the petroleum and natural gas industry 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. 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, 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, which negative impact could prove to be material over time. In addition, the Company could experience increased costs to retain and recruit these professionals.

Third Party Credit Risk

The Company is exposed to credit risk of third parties on the Royalty Properties.

The Company may be exposed to third-party credit risk through its royalty and contractual arrangements with the third parties on the Royalty Properties, including operators of the properties, marketers of its crude oil and natural gas take-in-kind volumes, if any, and other industry participants. In the event such entities fail to meet their royalty, contractual or financial obligations to the Company, such failures could materially adversely affect the Company's business and financial condition. Further, poor credit conditions may impact a third party's ability to fund the development and capital programs conducted on the Royalty Properties, which in turn could result in a reduction of the Company's revenues. In addition, poor credit conditions in the industry, generally, and of any third parties on the Royalty Properties may affect such third party's willingness to participate in the ongoing capital program on such Royalty Properties, potentially delaying the program and the results of such program until such third party finds a suitable alternative partner.

To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's business and financial condition. See "*Risk Factors – Dependence on Lessees and/or Operators*" and "*Risk Factors – Weakness in the Petroleum and Natural Gas Industry*".

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for crude oil and natural gas products and the rise of petroleum alternatives may negatively affect the Company's business and financial condition.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to crude oil and natural gas, and technological advances in fuel economy and renewable energy generation systems could reduce the demand for crude oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels, commitments to carbon reduction and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for crude oil and natural gas products. The Company cannot predict the impact of changing demand for crude oil and natural gas products, and any major changes may have a negative impact on the Company's business and financial condition by decreasing the Company's royalty revenues, limiting its access to capital and decreasing the value of its assets.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Company's financial condition.

World crude oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of crude oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States may indirectly negatively affect the Company's revenues, as revenues received by Canadian producers and, similarly, royalties payable to the Company, could decrease. Accordingly, exchange rates between Canada and the United States could affect the future value of the Company's reserves as determined by independent reserves evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively impact the price the Company and the lessees and/or operators of Royalty Properties receive for crude oil and natural gas production, it could also result in an increase in the price of certain goods used by lessees and operators of the Royalty Properties in their operations which may have a negative impact on the Company's financial results. Where the Company engages in risk management activities related to foreign exchange rates, there is a potential credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its activities and the cash available to pay dividends, and could negatively impact the market price of the Common Shares, which negative impact could prove to be material over time.

No Control over Operations on GORR Projects

The Company does not control operations on its GORR projects.

The Company has purchased several GORR Interests, including the royalties acquired pursuant to the Heritage Acquisition and the Marten Hills Acquisition, which are directly correlated to the operational results of crude oil and natural gas operations and hydrocarbons produced therefrom. The Company is not directly involved in the working interest ownership or operation of any of the projects on GORR Interests and has no contractual rights relating to the operation of such projects. The working interest owners and operators of crude oil and natural gas leases and licences will generally have the power to determine the manner in which the relevant properties subject to a royalty interest, including a GORR Interest, are exploited and developed, including decisions to expand, advance, continue, reduce, suspend or discontinue production from a property. The interests of the Company and the operators of the projects on the GORR Interests may not always be aligned. As a result, the royalty share of production and associated cash flows of the Company are dependent upon the activities of the operators as it relates to such projects, which creates the risk that at any time, such operator may: (i) have business interests or targets that are inconsistent with those of the Company; (ii) take action contrary to the Company's policies or objectives; (iii) be unable or unwilling to fulfill their obligations under their agreements with the Company; or (iv) experience financial, operational or other difficulties, including insolvency, which could limit the operators ability to continue operations and further develop such projects. At any time, the operator may decide to suspend or discontinue operations, including if the costs to operate a project exceed the revenues from operations. The Company will not be entitled to any compensation if such operations are shut down, suspended or discontinued on a temporary or permanent basis. There can be no assurance that the production from such projects will ultimately meet forecasts or targets. In addition, payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues. The payments pursuant to GORR Interests are calculated by the operator based on reported production and calculations of the Company's payments are subject to, and dependent upon, the adequacy and accuracy of the operators' production and accounting functions. Failure to receive payments under the GORR Interests to which the Company is entitled may have a material adverse effect on the Company and the dividend declared and paid by the Company. In addition, the Company must rely on the accuracy and timeliness of the public disclosure and other information it receives from the operator, and uses such information, including production estimates, in its analyses, forecasts and assessments relating to its own business. If the information provided by the operator to the Company contains material inaccuracies or omissions, the Company's ability to accurately forecast or achieve its stated objectives may be impaired.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on third parties' ability to produce and sell their crude oil and natural gas, as well as for the Company to sell production volumes it takes in-kind, which may affect the Company's business and financial condition.

The products produced from the Royalty Properties must be delivered through gathering and processing facilities and pipeline systems, none of which are owned by the Company and some of which are not owned by the third parties active on the Royalty Properties, and in certain circumstances, by rail. The amount of crude oil and natural gas produced and sold from the Royalty Properties is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits, and limits on availability of capacity in gathering and processing facilities continues to affect the petroleum and natural gas industry and limits the ability to transport produced crude oil and natural gas to market. In addition, the pro-rationing of capacity on interprovincial pipeline systems continues to affect the ability of crude oil and natural gas companies to export crude oil and natural gas, and could result in the inability of third parties to realize the full economic potential of the produced crude oil or natural gas or a reduction of the price offered for the production from the Royalty Properties. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work, natural disasters and environmental conditions, or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Company's business and financial condition. As a result, producers have considered rail lines as an alternative means of transportation.

Future pipeline projects may be terminated for reasons such as a failure to obtain government and/or regulatory support or approval. The direct impact that the termination of such projects will have on the Company is unknown.

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada, leading to increased awareness and challenges to interprovincial and international infrastructure projects. On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the Canadian Environmental Assessment Act, 2012 were repealed. In addition, the IA Agency replaced the CEA Agency. In the fall of 2023, the SCC found the IAA to be unconstitutional and the federal government is currently in the process of revising the IAA in an effort to make it compliant. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme, including the regime to be implemented under the revised IAA, and in the interim, the application of the Interim Guidance, on proponents and the timing for receipt of approvals of major projects is unknown. Projects which are subject to an impact assessment under both provincial and federal legislation, will likely be subject to a robust assessment of the environmental, social, health, economic and cultural impacts of a proposed project subject to the legislation, as well as the effects of projects on Indigenous peoples and their rights which may lead to longer periods to conduct the assessment and potentially more opportunities for public engagement and consultation. The production from the Royalty Properties is processed through facilities owned by third parties over which the Company, and in certain instances, the third parties on the Royalty Properties, have 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 operations could have a material adverse effect on the ability of the third parties to process production from the Royalty Properties and 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.

For royalty payments taken-in-kind by the Company, if any, the ability of the Company or a third-party marketer to successfully market in-kind crude oil and natural gas products may depend, in part, on the Company's or the third-party marketer's ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets. Deliverability uncertainties related to the distance the Company's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities, as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas and other aspects of the petroleum and natural gas industry may also affect the Company. See "*Risk Factors – Prices, Markets and Marketing*".

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for crude oil and natural gas and/or increase costs and/or delay planned operations on the Royalty Properties.

The implementation of new regulations or the modification of existing regulations affecting the petroleum and natural gas industry could reduce demand for crude oil and natural gas and increase costs or make certain projects on the Royalty Properties uneconomic, either of which could materially adversely affect the Company's business and financial condition. Further, the ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the petroleum and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access – Specific Pipeline and Proposed LNG Export Terminal Updates - Curtailment*".

In order to conduct crude oil and natural gas operations, third-party lessees and/or operators on the Royalty Properties will require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that third-party lessees and/or operators will be able to obtain all of the permits, licences, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake in the time required or on acceptable terms and conditions. Any failure to renew, maintain or obtain required permits, licences, registrations, approvals and authorizations or the revocation or termination of existing permits, licences, registrations, approvals and authorizations may disrupt such third-party lessee and/or operator operations and could have a resulting material adverse effect on the Company's business and financial condition. In addition, certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* could negatively affect the Company's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Environmental

Compliance with environmental regulations requires the dedication of a portion of the financial and operational resources of the lessees and/or operators of the Royalty Properties.

All phases of the crude oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and municipal 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 petroleum 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. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

As a royalty interest holder, the Company believes it has minimal or no direct exposure to environmental claims and regulation or the associated costs. However, such matters will directly impact the lessees and/or operators of the Royalty Properties. Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties on such lessees or operators, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of crude oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the lessee or operators of the Royalty Properties to incur costs to remedy such discharge. The Company requires the lessee or operators of the Royalty Properties to be in material compliance with current applicable environmental legislation; however, 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 associated with the Royalty Properties or otherwise have a negative effect on the Company's business and financial condition, which negative effect could prove material over time.

Stakeholders, the public and provincial and federal governments are becoming increasingly concerned about habitat and species protection, including degradation to biodiversity caused by economic activity. Accordingly, governments at various levels are increasing the rigour of existing acts and regulations and issuing changes aimed at improving environmental protection. Operations conducted by third-party operators may disturb the surrounding biodiversity of the Royalty Properties with the requirement for earth moving and the footprint of crude oil and natural gas operations. This may result in impacts to flora and fauna, including species at risk. Operations on the Royalty Properties may also be affected by conditions or restrictions on operations caused by wildlife habitat and migration patterns, endangered species or species at risk, and vegetation located on the Royalty Properties. Third-party operators may fail to achieve necessary permits or be subject to penalties or litigation if they cause habitat destruction or otherwise fail to mitigate impacts on biodiversity on the Royalty Properties. There is no assurance that third-party operators on the Royalty Properties will effectively limit habitat destruction or mitigate the impacts on biodiversity on the Royalty Properties. If they fail to do so, there may be decreased activities on the Royalty Properties, which could have an adverse effect on the Company's business and financial condition. See "*Industry Conditions - Regulatory Authorities and Environmental Regulation*".

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with a third party's ability to acquire properties or require a substantial cash deposit with the regulator, which may affect the Company's business and financial condition.

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 licencee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER continue to implement the AB LMF, completing the remaining amendments to the necessary directive and regulations to entirely phase-out the AB LMR Program. The implementation of the AB LMF or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by third party lessees or operators, increased and more frequent financial disclosure obligations or may result in the denial of licence or permit transfers, which could impact the availability of capital to be spent by third party lessees or operators which could in turn materially adversely affect the Company's business and financial condition. The impact and consequences of the SCC'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 AB LMF may prevent or interfere with a third party's ability to acquire or dispose of assets, as both the vendor and the purchaser of crude 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. British Columbia also introduced a new regime in April 2022, which may interfere with a third party’s ability to acquire or dispose of assets which may have an impact on the Company’s business and financial condition. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Royalty Regimes

Changes to royalty regimes may negatively impact the Company's cash flows and earnings.

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 third-party projects on the Royalty Properties. An increase in royalties could impact the financial condition of third parties operating on the Royalty Properties impacting future capital investment which could reduce the Company's business, financial condition, results of operations and prospects. British Columbia introduced a new royalty framework in May 2022 that comes into effect on September 1, 2024, with a number of incentives ending for any wells spudded after September 1, 2022. See "*Industry Conditions – Royalties and Incentives*".

Climate Change

Climate change may pose varied and far-ranging risks to the business and operations of third parties, both known and unknown, which may directly affect the Company's business and financial condition.

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada and the United States, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact. Subsequent conferences have generally reconfirmed the prior commitments made by the countries who participate in the United Nations Climate Change Conferences. See "*Industry Conditions – Climate Change Regulation*".

Transition Risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the operating expenses of some of the Company's royalty payors, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in the Company's profitability and a reduction in the value of its assets. *See "Risk Factors – Non-Governmental Organizations" and "Risk Factors – Reputational Risk".* Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including the Company, for alleged personal injury, property damage, or other potential liabilities. While the Company is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Company, impact its operations and have an adverse impact on its financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing and providing insurance coverage to oil and natural gas and related infrastructure businesses and projects. The impact of such efforts require the Company's management to dedicate significant time and resources to these climate change-related concerns, may adversely affect the Company's operations, the demand for and price of the Company's securities and may negatively impact the Company's cost of capital and access to the capital markets, which negative impact could prove to be material over time.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to ESG and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 – *Disclosure of Climate-related Matters,* intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If the Company is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. *See "Industry Conditions – Regulatory Authorities and Environmental Regulation" and "Industry Conditions – Climate Change Regulation"*.

Physical Risks

Based on the Company's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the ability of the Company's royalty payors to access their properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather may also increase the risk of personnel injury as a result of dangerous working conditions for third-party operations on the Royalty Properties.

Chronic Physical Climate Change Risks

Third-party operations and activities associated with the Royalty Properties emit GHGs which may require parties leasing and/or operating the Royalty Properties to comply with federal and/or provincial GHG emissions legislation. 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 to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effects could prove material over time. There is no guarantee the current provincial regimes in place will continue to meet federal stringency requirements and their continued application is subject to achieving the stringency standards as required by the federal government.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian petroleum and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. See "*Risk Factors – Seasonality*". In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require leasing or operating parties on the Royalty Properties to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety, which may in turn have a negative effect on production from the Royalty Properties, which negative effect could prove material over time. Specifically, in the event of water shortages or sourcing issues, third parties operating on the Royalty Properties may not be able to, or will incur greater costs to, carry out hydraulic fracturing.

Concerns over climate change, fossil fuels, GHG emissions and water and land-use could lead to reduced demand for the crude oil, natural gas and NGL that third party producers produce, which would have a material adverse effect on the Company's business, financial condition, results of operations and prospects. See "*Risk Factors – Alternatives to and Changing Demand for Petroleum Products"*.

Given the evolving nature of climate change policy 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, potentially reducing the demand for crude oil and natural gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or requiring impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Industry Conditions – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk*" and "*Risk Factors – Changing Investor Sentiment*".

Acute Physical Climate Change Risks

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 the operations of third-parties on the Royalty

Properties, increasing costs and negatively impacting the lessee or operator's production. Over the last several years, certain areas of British Columbia, Alberta and Saskatchewan have been negatively impacted by wildfires and, most recently with extreme flooding in British Columbia, causing temporary interruption to both pipeline systems and railway lines. Extreme weather conditions may lead to disruptions in the third-parties' ability to transport produced crude oil and natural gas as well as goods and services in their supply chains and meet demand due to temporary interruptions.

Certain of the Royalty Properties are located in locations 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 third-party operations on the Royalty Properties.

Exposure to Widespread Pandemic and Risks Related Thereto

The Company's business may be materially adversely affected by widespread global pandemics.

Pandemics, epidemics or outbreaks, including COVID-19, remain a risk for the Company, and the ultimate impact of a pandemic is highly uncertain and subject to change. A pandemic and the corresponding measures we take to protect the health and safety of our staff and the continuity of our business may result in new legal challenges and disputes, including, but not limited to, litigation involving contract parties or employees and class action claims. Actions taken by various levels of government and health authorities in the event of a pandemic, epidemic or outbreak may result in a reduction in the demand for, and prices of, commodities that are closely linked to our financial performance and may negatively impact our business, results of operations and financial condition. The Company may also be exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures which may be implemented in response to a pandemic.

In virtually all aspects of our business and strategy, our view of risks is not static as our business activities expose us to a variety of risks. Consistent with our Enterprise Risk Management Framework, we actively manage our risks to help protect and enable our business and future prospects. Additionally, we continue to evaluate the impacts, and any potential residual impacts that COVID-19 had and may continue to have on our business, including the impact on our principal and emerging risks, operational and reputational risks as well as credit, market and liquidity and funding risks and ESG risks. For further details on our risks, refer to the detailed risk factors below and throughout this AIF.

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

Events such as natural disasters, terrorist acts, global pandemics and other disruptions may pose varied and far-ranging risks to the business and operations of third parties, both known and unknown, which may directly affect the Company's business and financial condition.

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Company and its operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses, civil unrest 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 affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company, its customers and its operations.

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes for third parties, adversely affecting the Company's financial position.

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under high pressure into rock formations to stimulate the production of crude oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of crude oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the costs of compliance and doing business as well as delay the development of crude oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing on the Royalty Properties. Restrictions on hydraulic fracturing could also reduce the amount of crude oil and natural gas that is ultimately produced from the reserves associated with the Royalty Properties and, therefore, could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Alberta

Seismic events are common in certain parts of Alberta and are generally clustered around the municipalities of Red Deer, Cardston, Fox Creek and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek and the Red Deer region, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015 and subsequently in the Red Deer region in December 2019. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events and the suspension of operations if a seismic event above a particular threshold occurs. These requirements remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

British Columbia

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how B.C.'s regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. On February 20, 2019, the panel published its final report. The panel made 97 recommendations, primarily focused on addressing knowledge gaps and concerns regarding environmental impacts of hydraulic fracturing. Overall, the panel concluded that British Columbia's current regulations were robust; however, the implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect third-party operations on the Royalty Properties and the Company's business operations and financial condition.

Due to seismic activity recorded in the Kiskatinaw Area in May 2018, the BC Commission issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw Area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BC Commission, and the suspension of operations if a seismic event above a 3.0 magnitude occurs. In November 2018, seismic activity near Fort St. John in the Kiskatinaw Area resulted in the suspension of several companies' operations, demonstrating the BC Commission's willingness to enforce these enhanced regulatory requirements. The BC Commission continues to monitor seismic events across the province and may implement similar requirements in other areas if necessary.

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams which companies have built in association with their hydraulic fracturing operations. Under the Water Sustainability Act, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the Dam Safety Regulation. Larger dams are also subject to an environmental assessment and approval under the Environmental Assessment Act. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. While the BC Commission has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent, the relevant industry regulators will respond to this issue.

Third-party operators on the Royalty Properties may face operational delays if found to be not strictly compliant with the current regulatory framework.

Energy Transition

The global energy transition to a low-carbon economy may pose varied risks to the business and operations of third parties, both known and unknown, which may directly affect the Company's business and financial condition.

Globally, there is an increasing focus on transitioning to a low-carbon economy resulting in a number of policies and initiatives designed to shift resources and investment away from fossil fuels towards low carbon sources. This includes government regulations that restrict the production and consumption of fossil fuels such as zero emission vehicle mandates, prohibitions on plastic use, and fuel efficiency standards. Government subsidies directed towards new low-carbon technologies or to businesses providing products and services that reduce consumer demand for fossil fuels may also result in a broader reduction in the global economy's reliance on fossil fuels. In addition, shifting consumer preferences towards low-carbon products and services are also driving investment in technologies and products that reduce fossil fuel consumption. The Company is constantly evaluating its options with respect to increasing environmental efficiency through its operations. However, there can be no assurances that the Company will be able to predict any such market trends or consumer preferences. Accordingly, there is a risk that the nature of the global energy transition materially adversely affects the Company's business and financial condition.

Waterflood

Regulatory water use restrictions and/or limited access to water or other fluids may impact third-party operations on the Royalty Properties and production volumes from waterfloods.

Third-party operators on the Royalty Properties may undertake or intend 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, third-party operators need 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 third-party operators 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 third-party operators are unable to access such water they may not be able to undertake waterflooding activities, which may reduce the amount of crude oil and natural gas that the Company will ultimately receive from the Royalty Properties' reservoirs. In addition, third-party operators 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 business, financial condition, results of operations and prospects.

Disposal of Fluids used in Operations

Regulations regarding the disposal of fluids used in operations by third parties may increase costs of compliance or subject third-party operators on the Royalty Properties to regulatory penalties or litigation.

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from crude 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 costs of compliance for third-party operators on the Royalty Properties which may impact the economics of certain projects and in turn impact activity levels and new capital spending on the Royalty Properties.

Title to Assets

Defects in title to the Company's properties may result in a financial loss.

Although title reviews may be conducted prior to the purchase of fee simple mineral title interests or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise to defeat the Company's claim. The actual interest of the Company in the Royalty Properties may, therefore, vary from the records previously maintained by the prior owners. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which could materially adversely affect the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the Royalty Properties that, if successful or made into law, could impair our royalty interests and impact the Company's business, financial condition, results of operations and prospects.

Other Title Risks, including those applicable to Gross Overriding Royalties

Defects in title to the GORR Interests may result in a financial loss.

The majority of our GORR Interests attach to licences and leases and working interests in licences and leases. If 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 thereby terminating our GORR Interest. 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 a licence or lease or the working interest relating to a licence or lease may have a material adverse effect on our results of operations and business. In addition, title to the properties can become subject to dispute and defeat our claim to title over certain of our properties. Furthermore, there may be valid challenges to title or proposed legislative changes which affect title to the leases and licences to which our GORR Interests attach that, if successful or made into law, could impair our royalty interests and impact the Company's business, financial condition, results of operations and prospects.

Non-Governmental Organizations

The Royalty Properties and nearby facilities may be subject to action by non-governmental organizations or terrorist attack.

The petroleum and natural gas industry may, at times, be subject to public opposition. The oil and natural gas industry has become increasingly politically polarizing in Canada, which has resulted in civil disobedience surrounding oil and natural gas development, particularly with respect to infrastructure projects. Such public opposition could expose third-party operators on the Royalty Properties to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups which may include Indigenous groups, landowners, environmental interest groups (including those opposed to crude oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences, and direct legal challenges, including the possibility of climate-related litigation (see "*Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints and Market Access*"). There is no guarantee that third-party operators on the Royalty Properties will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require significant and unanticipated capital and operating expenditures which may negatively impact the Company's business, financial condition, results of operations and prospects, which negative impact could prove to be material over time.

Availability and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede third parties' exploration, development and operating activities, which may affect the Company's business and financial condition.

Crude oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in areas where such activities will be conducted. The availability of such material and equipment is limited. The oil and natural 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. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede third-party operations on the Royalty Properties and may delay such exploration, development and operating activities, which, in turn, could materially adversely affect the Company's business and financial condition.

Diluent Supply

A decrease in, or restriction in access to, diluent supply may reduce the Company's royalty revenues.

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent, or a restriction in access to diluent, may cause its price to increase, increasing the cost to transport heavy oil and bitumen to market. An increase to the cost of bringing heavy oil and bitumen to market would reduce the Company's overall royalty revenues.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for crude oil and natural gas and the operating costs for third-party operators on the Royalty Properties and may impair their ability to compete.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government 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 stringency 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*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for crude oil and natural gas products and at the same time, increasing the operating expenses of crude oil and natural gas companies, each of which may have a material adverse effect on the Company's revenue from the Royalty Properties. Further, the imposition of carbon taxes puts companies at an economic disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Insurance

Not all business risks are insurable and the occurrence of an uninsurable event may have an adverse effect on the Company.

Although the Company maintains insurance in accordance with industry standards to address certain risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums or retentions associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The lessees of the Royalty Properties may fail to meet the requirements of a licence or lease, causing its termination or expiry.

Certain of the Company's Royalty Properties are tied to licences and leases and working interests in licences and leases. If 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 these licences or leases or the working interests relating to a licence or lease may impair certain of the Royalty Interests and in turn may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Litigation

The Company may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Company and its reputation.

In the normal course of the Company's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to property damage, personal injury, property tax, land rights, royalty rights, access rights, environmental issues and lease or contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty, may be determined adversely to the Company and could have a material adverse effect on the Company's business, financial condition and funds from operations. Even if the Company prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Company's business and financial condition.

Indigenous Claims

Indigenous claims and interpretation of historical treaties may affect the Company.

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. In particular, certain aboriginal groups have challenged title to lands near the Fee Lands and the GORR Lands. Claims and protests of Indigenous peoples may disrupt or delay third-party operations, new development or new project approvals on the Royalty Properties. 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 negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time. 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 negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Moreover, in recent years there has been increasing litigation regarding historical treaties with Indigenous peoples in Canada. Judicial interpretation of such historical treaties, and in particular the rights granted thereunder to Indigenous nations to manage and use the lands in a manner consistent with their ancestral practices, may impact future resource and industrial development in and around these lands. While the potential impact of current and future judicial decisions is uncertain at this time, it is possible that such decisions may have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time. See "*Industry Conditions - Indigenous Rights*".

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved, and the Company may dispose of certain non-core assets for less than their carrying value on the financial statements as a result of weak market conditions.

While management is focused on encouraging third parties to develop the Royalty Properties, the Company also considers acquisitions and dispositions of certain royalty 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. Acquisitions are based in large part on engineering, environmental and economic assessments. These assessments include a number of assumptions regarding factors such as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future commodity prices, operating costs and capital expenditures and royalties and other government levies which may be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control 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. The Company may also enter into other industry-related activities or new geographical areas or acquire different energy-related assets that may result in unexpected or significantly increased risk to the Company, which could materially adversely affect the Company's business, financial condition, results of operations and prospects. Management continually assesses the value and contribution of the various properties and assets within its portfolio. In this regard, the Company may consider disposing of certain non-core assets in order to focus its efforts and resources more efficiently. Depending on market conditions for such non-core assets, the Company may realize less on disposition of certain core assets than their carrying value on the financial statements of the Company.

Industry Competition

The petroleum and natural gas industry is competitive and the Company may be unable to maintain competitiveness within the industry.

The petroleum and natural gas industry is competitive throughout its lifecycle. The Company competes with numerous other entities in the search for, and the acquisition of, petroleum and natural gas properties and in the marketing of petroleum and natural gas. In particular, the Company competes with other companies for the acquisition of royalty interests in petroleum and natural gas properties. Other companies may have access to substantially greater financial resources, staff and facilities than those of the Company and who may have lower costs of, and better access to, capital. The Company's ability to increase its reserves in the future will depend partially on its and its partners' and royalty payors' ability to explore and develop its present properties but will primarily depend on its ability to acquire royalty interests in suitable producing properties or properties with future reserve or resource potential.

Management of Growth and Integration

The Company may not be able to effectively manage the growth of its business.

The Company may be subject to both transition and growth-related risks, including capacity constraints and pressure on its internal systems and controls. In particular, the Company is responsible for managing a substantial number of land and title documents and related accounting functions that require significant employee resources. The ability of the Company to manage future growth and integration of additional lands, leases and acquisitions effectively requires it to continue to implement and improve financial and land systems and to expand, train and manage its employee base. The inability of the Company to deal with this integration and growth may have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Reserves Estimates

The Company's estimated reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Company.

There are numerous uncertainties inherent in estimating reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this AIF are estimates only. Generally, estimates of economically recoverable crude oil and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves which are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- commodity prices;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures by the working interest owners thereon;
- marketability of crude oil and natural gas;
- royalty rates (which, in the case of the Company, generally consist of the royalties to be paid to the Company); and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For these reasons, estimates of the economically recoverable crude oil, natural gas and NGL reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Company's actual net production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, GLJ, the Company's independent qualified reserves evaluator, has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for crude oil and natural gas, curtailments or increases in consumption by crude oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Company's crude oil, natural gas and NGL reserves will vary from the estimates contained in the GLJ Report and such variations could be material. The GLJ Report is effective as of December 31, 2023, with a preparation date of January 10, 2024, and, except as may be specifically stated or required by applicable securities laws, has not been updated and, therefore, does not reflect changes in reserves since that date.

Market Price of Common Shares

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the petroleum and natural gas industry.

The trading price of the 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. 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 crude oil and natural gas commodity prices, and the securities of issuers involved in the crude oil and natural gas business, has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. Similarly, recent market prices in the securities of crude oil and natural gas issuers relative to other industry sectors have led to lower crude oil and natural gas representation in certain key equity market indices. The volatility, trading volume and market price of crude oil and natural gas have been impacted by increasing investment levels in passive funds that track major indices and only purchase securities included in such indices and subsequently dispose of those securities if they are excluded from such indices. In addition, many institutional investors, pension funds and insurance companies, including government sponsored entities, have implemented investment strategies increasing their investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. These factors have impacted the volatility and liquidity of certain securities and put downward pressure on the market price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Capital and Additional Funding Requirements

The Company may require additional financing from time to time to fund the acquisition of additional royalty interests and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility.

The Company's cash flow from the Royalty Properties may not be sufficient to fund its ongoing activities at all times, and from time to time the Company may require additional financing, which may include financing for the acquisition of crude oil and natural gas assets. Future acquisitions and other expenditures will be financed out of cash flow from royalty revenues, borrowings and possible future equity issuances and the Company's ability to do so will be dependent on, among other factors: the overall state of the capital markets; commodity prices; interest rates; tax burden due to current and future tax laws; and investor appetite for investments in the energy industry and the Company's securities in particular. Failure to obtain financing on a timely basis could cause the Company to miss certain acquisition opportunities. Due to the conditions in the petroleum and natural gas industry and/or global economic and political conditions and the domestic lending landscape, the Company may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the petroleum and natural gas industry have negatively impacted the cost and/or ability of crude oil and natural gas companies to access, or the cost of, additional financing.

There can be no assurance that debt or equity financing, or cash flow generated by operations, will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. Alternatively, any available financing may be highly dilutive to existing shareholders. There is risk that if the economy and banking industry experience unexpected and/or prolonged deterioration, the Company's access to additional financing may be affected. The inability of the Company to access sufficient capital for its operations could cause the Company to, amongst other things, miss certain acquisition opportunities and may materially adversely affect the Company's business and financial condition.

In addition, the future development of the Royalty Properties by third parties may require additional financing and there are no assurances that such financing will be available, and, if available, will be available upon acceptable terms to such third parties. Failure to obtain any financing necessary for such third parties' capital expenditure plans may result in a delay in development of the Royalty Properties.

Changing Investor Sentiment

Changing investor sentiment towards the petroleum and natural gas industry may impact the Company's access to, and cost of, capital.

A number of factors, including the effects of the use of fossil fuels on climate change, GHG emissions reduction, the impact of crude oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the petroleum and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount of their investments of such entities over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices, including the use of environmental metrics in executive compensation. Developing and implementing such policies and practices can be costly 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 petroleum 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 Common Shares, 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 assets which may result in an impairment charge.

Evolving Corporate Governance, Sustainability and Reporting Framework

Evolving corporate governance, sustainability and reporting framework may increase both compliance costs and the risk of non-compliance that may have an adverse effect on the Company.

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. The Company 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.

Reputational Risk

The Company relies on its reputation to continue its operations and to attract and retain investors and employees.

The Company's business, financial condition, operations or prospects may be negatively impacted, which negative impact could prove to be material over time, as a result of any negative public opinion toward 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 crude 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 licences and increased costs and/or cost overruns. Any environmental damage, loss of life, injury or damage to property caused by third-party operations on the Royalty Properties could damage the reputation of the lessees or operators of the Royalty Properties and, in turn, the Company, in the areas in which the Company holds Royalty Properties. Negative sentiment towards any of the lessees or operators of the Royalty Properties could result in a lack of willingness of governmental authorities to grant the necessary licences or permits for those lessees or operators to operate their business and in residents in the areas where such lessees or operators are doing business opposing further operations by such lessees or operators in the area, which could negatively impact the Company's revenues, which negative impact could prove to be material over time. The Company's reputation could be affected by actions and activities of other corporations operating in the petroleum and natural gas industry, over which the Company has no control. If the Company, either directly or indirectly develops a reputation of having an unsafe workplace it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. In addition, environmental damage, loss of life, injury or damage to property caused by third parties operating on the Royalty Properties and/or indirectly by the Company's business could result in negative investor sentiment towards the Company. Opposition from special interest groups opposed to crude oil and natural gas development and the possibility of climate-related litigation against fossil fuel companies may indirectly harm the Company's reputation.

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.

Dividends

The amount of and frequency at which future cash dividends are paid may vary and there is no assurance that the Company will pay dividends in the future.

The amount of future cash dividends paid by the Company is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices; production levels; financial condition of the Company; results of operations; capital expenditure requirements; working capital requirements; operating costs; current and expected future levels of earnings; liquidity requirements; market opportunities; income taxes; debt repayments; legal, regulatory, and contractual constraints; the Company's risk management activities or programs; the Company's business plan, strategies and objectives; tax laws; foreign exchange rates; interest rates; and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which are beyond the control of the Company, the Company's dividend policy and, as a result, future cash dividends, could be reduced or suspended entirely, from time to time. The Sustainable Credit Facility may prohibit the Company from paying dividends at any time at which a default or event of default has occurred and is continuing, or if a default or event of default would exist as a result of paying the dividend.

Over time, the Company's capital and other cash needs may change significantly from its current needs, which could affect whether the Company pays dividends and the amount of dividends, if any, it may pay in the future. If the Company continues to pay dividends at the current levels, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn. The Board may amend, revoke or suspend the Company's dividend policy at any time. A decline in the market price, liquidity, or both, of the Common Shares could result if the Company reduces or eliminates the payment of dividends, which could result in losses to shareholders.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which may result from lower commodity prices and/or lower royalty production volumes, and any decision by the Company to finance capital expenditures using funds from operations.

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, the ability of the Company to make the necessary incremental royalty acquisitions to maintain or expand petroleum and natural gas reserves will be impaired. To the extent that the Company is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Foreign Exchange Risk on Dividends

Variations in foreign exchange rates may affect the amount of cash dividends received by shareholders who receive dividends in currencies other than Canadian dollars.

The Company's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to the shareholder's home currency.

Additional Taxation Applicable to Dividends Paid to Non-Residents

Non-resident shareholders are required to pay additional taxes on their dividends.

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Where a non-resident is a United States resident entitled to benefits of the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%. In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

Hedging

Hedging activities may expose the Company to the risk of financial loss and counter-party risk.

The Company may enter into hedging arrangements to fix interest rates applicable to the Company's debt. However, if interest rates decrease as compared to the interest rate fixed by the Company, the Company will not benefit from the lower interest rate.

While the Company does not currently hedge any commodity price risk, the Company may in the future enter into agreements to receive fixed prices on its crude oil and natural gas royalty production volumes, if any, 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, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. 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;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- 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 United States 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.

Income Taxes

Taxation authorities may reassess the Company's tax returns.

The Company files all required income tax returns in order to be in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, such reassessment may have an impact on current and future taxes payable.

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

Issuance of Debt

Increased debt levels may impair the Company's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

From time to time, the Company may finance its activities (including potential future crude oil and natural gas royalty asset acquisitions) in whole or in part with debt, which may increase the Company's debt levels above industry standards for peers of similar size. Additional debt financing 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.

Competition

The Company competes with other entities to encourage the development of the Royalty Properties and to acquire additional royalty interests, some of which have greater financial resources, staff or political influence.

The petroleum and natural gas industry is highly competitive in all of its phases. The Company competes with numerous other entities to encourage third-party development of the Royalty Properties and to acquire additional crude oil and natural gas interests. The Company's competitors include other fee simple mineral title owners, exploration and production companies and the Provincial and Federal Crown, as the owners of the significant majority of mineral rights in Western Canada, any of whom may have more financial resources, staff or political influence than the Company. The Company's ability to increase its reserves and revenue streams in the future will depend not only on its ability to promote development of the Royalty Properties, but also on its ability to select other suitable producing properties or prospects for third-party exploratory drilling and further development.

Conflicts of Interest

Conflicts of interest may arise for the Company's directors and officers who are also involved with other industry participants.

Certain members of the Board and management are also, or may in the future be, directors or officers of other crude oil and natural gas companies that may compete or be counterparties to agreements with the Company and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA and Company policies which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract, or material transaction, or proposed material transaction, with the Company disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. The Company also has additional policies in place which require management to seek approvals of independent directors in certain situations where there may be a perceived or potential conflict of interest arising due to interlocking directorships, despite the transaction being within management's authorization levels and not otherwise requiring Board approval.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Company's competitive advantage or put it at risk of litigation.

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of the Company. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information by the Company, 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 solely in monetary 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.

Information Technology Systems and Cyber-Security

Breaches of the Company's cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position.

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 its land base, manage financial resources, analyze seismic information, administer its contracts with its operators and lessees and communicate with employees and third-party operators.

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 its 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, including a cybersecurity incident response plan, that address and implement employee protocols with respect to electronic communications and electronic devices and conducts periodic 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, phishing activities remain a serious problem that may damage our 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 reputation, performance and earnings, which negative effect could prove to be material over time, 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, results of operations and prospects.

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

Shareholders in the United States have a limited ability to enforce civil remedies against the Company in Canada.

The Company is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of our directors and 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.

Social Media

The Company faces compliance and supervisory challenges in respect of the use of social media as a means of communicating with clients and the general public.

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

Negative Impact of Additional Sales or Issuances of Common Shares

The Company may issue additional Common Shares, diluting current shareholders.

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.

Forward-Looking Information

Forward-looking information may prove inaccurate.

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking statements. By their nature, forward-looking statements involve 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 statements 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 under the heading "*Cautionary Statement Regarding Forward-Looking Information and Statements*" in this AIF.

Description of Capital Structure

The authorized share capital of the Company includes an unlimited number of Common Shares and an unlimited number of preferred shares issuable in series. As of February 12, 2024, 238,952,008 Common Shares and nil preferred shares were issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions which are attached to the Common Shares and preferred shares.

COMMON SHARES

The rights, privileges, restrictions and conditions attaching to the Common Shares are set forth below.

Voting Rights

The holders of the Common Shares are entitled to one vote in respect of each Common Share held at all meetings of shareholders, except meetings at which only holders of a specified class of shares have the right to vote.

Dividends

Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company, holders of Common Shares are entitled to receive any dividend declared by the Company on the Common Shares.

Rights upon Dissolution

Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company, holders of Common Shares are entitled to receive the remaining property of the Company upon dissolution.

Preferred Shares

The Board may issue preferred shares at any time and from time to time in one or more series, and shall determine the rights, privileges, restrictions and conditions attached to each series of preferred shares before the issue of such series.

Dividends

Preferred shares may be entitled to preference over the Common Shares and any other shares of the Company ranking junior to the preferred shares with respect to payment of dividends.

Rights upon Dissolution

Preferred shares may be entitled to preference over the Common Shares and any other shares of the Company ranking junior to the preferred shares with respect to distribution of assets in the event of liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary.

Market for Securities

TRADING VOLUME AND PRICE

The Common Shares are listed and trade on the TSX under the symbol "PSK". The following table sets forth the high and low trading prices and the aggregate trading volume of the Common Shares on the TSX for the periods indicated. During 2023, the Company purchased, for cancellation, nil Common Shares under its NCIB.

Toronto Stock Exchange

	High ($/Common Share)	Low ($/Common Share)	Volume Traded
2023			
January	23.46	20.23	11,960,219
February	23.55	21.38	8,079,695
March	22.60	19.55	12,553,970
April	22.33	20.41	10,202,016
May	23.62	20.69	10,497,892
June	24.66	22.76	7,401,302
July	26.90	22.97	9,373,308
August	26.90	25.68	7,233,621
September	26.29	24.50	7,895,952
October	25.28	23.74	6,898,258
November	25.45	23.49	6,772,165
December	25.16	22.91	7,222,510
2024			
January	24.00	21.59	6,350,766
February (1-9)	22.48	21.22	1,576,564

Dividends

In each quarter of 2023, the Board declared a dividend of $0.24 per Common Share or $0.96 per Common Share on an annualized basis. On February 12, 2024, the Company announced that the Board had approved an increase in the dividend to $0.25 per Common Share per quarter or $1.00 per Common Share on an annualized basis, effective for the March 29, 2024 dividend record date which is expected to be paid on or about April 15, 2024.

The Board reviews and determines the dividend rate annually after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, taxes payable, and PrairieSky's capacity to fund operating and investing opportunities. The dividend rate is established with the intent of absorbing market volatility, including commodity price volatility. It also recognizes the intention of maintaining a strong financial position to take advantage of business development opportunities and withstand periods of commodity price volatility.

Dividends are paid quarterly to shareholders of record as of the close of business on the last business day of each quarter, with the 15th day (or next business day) of the following month being the corresponding payment date. Dividend payments are not guaranteed and the amount of cash to be distributed as dividends in the future may change. Any decision to pay dividends will be determined at the discretion of the Board after reviewing the overall dividend policy of the Company and after consideration of numerous factors including: (i) the earnings of the Company; (ii) financial requirements for the Company's operations; (iii) the satisfaction by the Company of liquidity and insolvency tests described in the ABCA; and (iv) any agreements relating to the Company's indebtedness that restrict the declaration and payment of dividends. The dividends paid on the Common Shares pursuant to the Company's dividend policy are designated as "eligible dividends" for Canadian income tax purposes, unless otherwise notified.

The per Common Share cash dividends set forth in the table below have been paid by the Company to its shareholders in the months indicated for the last three years.

Month of Dividend Payment Date	**Year**		
	2021	**2022**	**2023**
January	$0.060	$0.090	$0.240
February	-	-	-
March	-	-	-
April	$0.065	$0.120	$0.240
May	-	-	-
June	-	-	-
July	$0.065	$0.120	$0.240
August	-	-	-
September	-	-	-
October	$0.090	$0.120	$0.240
November	-	-	-
December	-	-	-

The historical cash dividend payments described above may not be reflective of future dividend payments, and future dividend payments are not assumed or guaranteed.

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, PrairieSky believes it may be classified as a passive foreign investment company (*PFIC*) under United States federal income tax principles. As such, dividends to taxable individual shareholders who are United States taxpayers should continue to be subject to the regimes of United States federal income taxation applicable to PFICs. Shareholders who are United States taxpayers should discuss with their tax advisors the reporting requirements with respect to owning shares in a PFIC. In order to allow shareholders the ability to make a Qualified Electing Fund election, PrairieSky posts annually a PFIC Annual Information Statement on its website. Shareholders should contact their own tax advisors for information on correctly completing Form 8621. This information is not available from PrairieSky.

Directors and Executive Officers

BOARD OF DIRECTORS OF PRAIRIESKY

As at February 12, 2024, the Board is comprised of ten (10) individuals. The name, province of residence, principal occupation of each director of PrairieSky are set out below. The term of office of all directors of the Company will expire at the next annual meeting of shareholders of the Company and, thereafter, at each annual meeting of shareholders of the Company or at the time at which his or her successor is elected or appointed, or earlier if any director otherwise dies, resigns, is removed or is disqualified.

On October 23, 2023, the Company announced that James Estey intends to retire as Chair of the Board and director at the 2024 Annual General Meeting and Grant Zawalsky will not stand for re-election as a director. The Company also announced that the Board intends to appoint Margaret McKenzie, who has served on the Board since 2014, as the Board Chair following the 2024 Annual General Meeting. Anna Alderson was appointed to the Board effective October 23, 2023 and is a member of the Audit Committee. Glenn McNamara was appointed to the Board effective December 4, 2023 and is a member of the Reserves Committee.

Name, Province and Country of Residence	Principal Occupation	Director Since
James M. Estey(1) Calgary, Alberta, Canada	Corporate Director	April 11, 2014
Anna M. Alderson(2) Calgary, Alberta, Canada	Corporate Director	October 23, 2023
Leanne Bellegarde, KC(2) Saskatoon, Saskatchewan, Canada	President, Akawe Technologies Inc.	June 9, 2021
Anuroop S. Duggal(3)(4) Calgary, Alberta, Canada	Private Investor Corporate Director	April 18, 2023
P. Jane Gavan(3) Toronto, Ontario, Canada	President, Asset Management of Dream Unlimited Corp.	May 23, 2019
Margaret A. McKenzie(1)(2) Calgary, Alberta, Canada	Corporate Director	December 19, 2014
Glenn A. McNamara(4) Calgary, Alberta, Canada	Corporate Director	December 4, 2023
Andrew M. Phillips Calgary, Alberta, Canada	President & Chief Executive Officer of the Company	April 11, 2014
Sheldon B. Steeves(2)(3)(4) Calgary, Alberta, Canada	Corporate Director	April 11, 2014
Grant A. Zawalsky(4)(5) Calgary, Alberta, Canada	Vice-Chair and Partner, Burnet, Duckworth & Palmer LLP	December 19, 2014

Notes:

(1) Chair of the Board. Mr. Estey is expected to retire as Chair of the Board and director at the 2024 Annual General Meeting. The Board has announced its intention to appoint Ms. McKenzie as Chair of the Board following the 2024 Annual General Meeting.
(2) Member of the Audit Committee. Ms. McKenzie is the Chair of the Audit Committee.
(3) Member of the Governance and Compensation Committee. Ms. Gavan is the Chair of the Governance and Compensation Committee.
(4) Member of the Reserves Committee. Mr. Steeves is the Chair of the Reserves Committee.
(5) Mr. Zawalsky will not stand for re-election at the 2024 Annual General Meeting.

EXECUTIVE OFFICERS OF PRAIRIESKY

The following table sets forth the name, province and country of residence, position(s) held with the Company and date of appointment of each of the executive officers of PrairieSky.

Name, Province and Country of Residence	Principal Occupation	Date of Appointment as an Officer
Andrew M. Phillips Calgary, Alberta, Canada	President & Chief Executive Officer	April 11, 2014
Pamela P. Kazeil Calgary, Alberta, Canada	Vice-President, Finance & Chief Financial Officer	June 1, 2015
Daniel J. Bertram Calgary, Alberta, Canada	Vice-President, Business Development & Chief Commercial Officer	October 10, 2023
Michael Murphy Calgary, Alberta, Canada	Vice-President, Geosciences & Capital Markets	January 29, 2024

As at February 12, 2024, the directors and executive officers of PrairieSky, as a group, beneficially own or control, directly or indirectly, 2.8 million Common Shares or approximately 1.2% of the issued and outstanding Common Shares.

DIRECTORS AND EXECUTIVE OFFICERS BIOGRAPHICAL INFORMATION

The following are brief profiles of each of the directors and executive officers of the Company, which include a description of their present occupation and their principal occupations for the past five years.

James M. Estey

Mr. Estey's principal occupation is as a Corporate Director. Mr. Estey is the retired Chairman of UBS Securities Canada Inc., a financial services company, and has more than 40 years of experience in financial markets. Mr. Estey joined Alfred Bunting and Company as an institutional equity salesperson in 1980 after working at A.E. Ames & Co. for seven years. In 1994, Mr. Estey became the head of the Canadian Equities business, and in 2002 Mr. Estey was appointed President & Chief Executive Officer of UBS Securities Canada Inc. In January 2008, Mr. Estey assumed the role of Chairman of UBS Securities Canada Inc. Mr. Estey is a director and Chairman of Gibson Energy Inc., a TSX-listed crude oil and natural gas infrastructure company. Mr. Estey also serves on the Advisory Board of the Edwards School of Business at the University of Saskatchewan.

Anna M. Alderson

Ms. Alderson is an experienced Corporate Director based in Calgary with over 35 years of experience in all sectors of the energy industry as well as financial services. Ms. Alderson retired from KPMG LLP in 2019 after a distinguished career as an audit partner in Calgary, Toronto and Hong Kong. Ms. Alderson is a Chartered Professional Accountant, holds her ICD.D designation from the Institute of Corporate Directors and earned a Bachelor of Commerce degree (with great distinction) from the University of Saskatchewan. Ms. Alderson is also a director of Tenaz Energy Corp., a TSX-listed oil and gas exploration company with assets in Canada and Europe.

Leanne M. Bellegarde, KC

Ms. Bellegarde is currently the President of Akawe Technologies Inc., a technology company focused on supporting Canadian entrepreneurs and indigenous groups, and a member of the Board of Governors at the University of Regina. Ms. Bellegarde has extensive business and executive experience in senior roles with Potash Corp., Nutrien Ltd. and the Saskatchewan Indian Gaming Authority. Ms. Bellegarde is also the former General Counsel to the Federation of Saskatchewan Indian Nations, and a former director of SaskEnergy, Sustainable Development Technologies Canada as well as several other private businesses and not for profit and community organizations. Ms. Bellegarde holds a Bachelor of Laws degree from the University of Saskatchewan, was appointed King's Counsel in 2017 and was the recipient of the Diamond Jubilee Medal in

2012. Ms. Bellegarde currently sits on the board of directors of the Saskatchewan Research Council and several private business enterprises. Ms. Bellegarde is from Treaty 4 Territory in south Saskatchewan and is a proud member of the Peepeekisis Cree Nation.

Anuroop S. Duggal

Mr. Duggal is a private investor since 2018 with significant institutional investing experience with the global energy sector. He was a partner at 3G Capital, a global multi-billion dollar asset manager, where he helped launch, manage and grow a natural resource focused equity and credit fund. Prior to that he was an investor with Goldman Sachs Investment Partners, which was the Asset Management division's flagship hedge fund. Mr. Duggal was also an Adjunct Professor for the MBA program at Columbia Business School where he taught value investing courses through the Heilbrunn Center for Graham & Dodd Investing for seven years. Mr. Duggal graduated from the University of Western Ontario with an Honors Business Administration degree (Richard Ivey School of Business, gold medalist) and an Electrical Engineering degree. Mr. Duggal currently also sits on the board of directors of Calfrac Well Services Ltd., a provider of specialized oilfield services, and Optiva Inc., a provider of software to the telecommunications industry, both of which are listed on the TSX.

P. Jane Gavan

Ms. Gavan is President, Asset Management of Dream Unlimited Corp., a real estate development company, having held increasingly senior positions since joining Dream's predecessor organization in 1998. Ms. Gavan has previously served as Chief Executive Officer of Dream Residential REIT, Dream Global REIT and Dream Office REIT, all of which are or were listed on the TSX. Ms. Gavan has more than 30 years of executive business and leadership experience across a number of industries, including acting as a senior legal advisor prior to joining Dream Global. Ms. Gavan earned an Honours Bachelor of Commerce degree from Carleton University and a Bachelor of Laws degree from Osgoode Hall, York University. Ms. Gavan currently also sits on the board of directors of Dream Unlimited Corp., Dream Residential REIT, Dream Office REIT, Colliers International Group Inc. and is on the Patron's Council for Community Living Toronto.

Margaret A. McKenzie

Ms. McKenzie's principal occupation is as a Corporate Director. Ms. McKenzie was the Vice-President, Finance and Chief Financial Officer of Range Royalty from 2006-2014 and prior thereto was Vice-President, Finance and Chief Financial Officer of Profico Energy Management Ltd. (a private oil and natural gas company). Ms. McKenzie holds a Bachelor of Commerce degree (with distinction) from the University of Saskatchewan and has been a member of the Chartered Professional Accountants of Alberta since 1985. She obtained her ICD.D designation from the Institute of Corporate Directors in 2013. Ms. McKenzie is an experienced director and currently sits as a director of Canadian National Railway Company, a TSX- and NYSE-listed leader in North American transportation and logistics.

Glenn A. McNamara

Mr. McNamara is a Professional Engineer with more than forty years of oil and gas exploration and production experience in progressively more senior roles in Canada and across a variety of international regions, including South America, the United States, Europe and Asia Pacific. His extensive commercial and operational experience spans both large organizations and smaller entrepreneurial environments, most recently serving as President & Chief Executive Officer and a director of Heritage Royalty. Prior to, Mr. McNamara's experience included serving as President of BG Canada, responsible for all aspects of BG Canada's business and holding several senior executive positions with ExxonMobil, ExxonMobil Canada, and Mobil Oil Canada, including President of ExxonMobil Canada West. Mr. McNamara is also a director of Whitecap Resources Inc. and Parex Resources Inc.

Andrew M. Phillips

Mr. Phillips is the President and Chief Executive Officer of the Company and has over 20 years of experience in the petroleum and natural gas industry in the areas of exploration, geology, business development, asset evaluation and executive management. Prior to his appointment as President and Chief Executive Officer of the Company, Mr. Phillips was the President and Chief Executive Officer and a director of Home Quarter Resources Ltd. (*Home Quarter*), a private oil and natural gas company founded by Mr. Phillips in 2010 with producing properties and royalty interests in southwest Saskatchewan and Alberta. Home Quarter was successfully divested to a public oil and natural gas company in 2014. Prior thereto, Mr. Phillips was the Vice-President, Exploration at Evolve Exploration Ltd., a private junior oil and natural gas company with assets in Western Canada, and an exploration geologist at each of Profico Energy Management Ltd. and Renaissance Energy Ltd., both of which were Canadian oil and natural gas exploration companies. Mr. Phillips holds a Bachelor of Science, Geology degree from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta and the Canadian Society of Petroleum Geologists. Mr. Phillips is a member of the Board of Directors of the Alberta Children's Hospital Foundation.

Sheldon B. Steeves

Mr. Steeves' principal occupation is as a Corporate Director. Mr. Steeves is a director of Enerplus Corporation, a crude oil and natural gas company listed on the TSX. From January 2001 until April 2012, Mr. Steeves was Chairman and Chief Executive Officer of Echoex Ltd., a private junior oil and natural gas company, and spent over 15 years at Renaissance Energy Ltd., a Canadian oil and gas exploration company, where he was appointed Chief Operating Officer & Executive Vice-President in 1997. Mr. Steeves holds a Bachelor of Science degree in Geology from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

Grant A. Zawalsky

Mr. Zawalsky is Vice-Chair and partner of Burnet, Duckworth & Palmer LLP (Barristers and Solicitors) where he has been a partner since 1994 and was managing partner from January 1, 2012 to January 31, 2022. Mr. Zawalsky holds a B.Comm and LL.B. from the University of Alberta and is a member of the Law Society of Alberta. Mr. Zawalsky is an experienced director and currently sits on a number of public and private boards of directors including Whitecap Resources Inc. and NuVista Energy Ltd.

Pamela P. Kazeil

Ms. Kazeil is the Vice-President, Finance & Chief Financial Officer of the Company, and has significant experience in the petroleum and natural gas industry managing finance, accounting, treasury, sustainability, tax and risk management. Prior to joining the Company, Ms. Kazeil held the Chief Financial Officer position at Sinopec Canada. Ms. Kazeil's experience includes serving as Vice-President, Finance of Daylight Energy Ltd. from 2008 to 2011, and prior thereto Ms. Kazeil held increasingly senior finance roles with Sword Energy Ltd. and its predecessor Thunder Energy Trust from 2004 to 2008, including as Vice-President, Finance and Chief Financial Officer. Ms. Kazeil started her accounting career at KPMG LLP in 2001. Ms. Kazeil is a Chartered Professional Accountant, a Fundamentals of Sustainability Accounting (FSA) Credential Holder and holds a Bachelor of Commerce degree from the University of Ottawa and a Bachelor of Education degree from the University of Saskatchewan. Ms. Kazeil is a member of the Board of the United Way Calgary and Area.

Daniel J. Bertram

Mr. Bertram is the Vice-President, Business Development & Chief Commercial Officer of the Company. Prior thereto, Mr. Bertram was the Senior Vice-President and Chief Strategy Officer at Superior Plus Corp., a leading North American energy distributor. From 2019 to 2023, Mr. Bertram was the Vice-President, Business Development at Certarus Ltd. and previously spent over five years at Alaris Royalty Corp. as Vice-President, Business Development, leading their origination and deployment efforts. Earlier in his career, he worked for Deans Knight Capital Management as an Investment Analyst and spent time in the investment banking industry. Mr. Bertram graduated in finance from Boston College and holds a CFA designation. Mr. Bertram is a member of the Board of the Edge School Athletes Society.

Michael T. Murphy

Mr. Murphy is the Vice-President, Geosciences and Capital Markets of the Company and has 19 years of experience across the oil and gas industry and related capital markets. Prior to joining the Company in January 2024, Mr. Murphy spent 10 years in sell side equity research focused on the energy sector. Most recently, he was an Analyst as part of a top-ranked equity research team at BMO Capital Markets, covering Canadian small/mid-cap exploration and production and royalty companies. Prior thereto, Mr. Murphy was a Senior Research Associate at Macquarie Capital Markets Canada. Mr. Murphy started his career as a geologist at multiple junior public oil and gas companies in roles of increasing responsibility, focused on both the Western Canadian Sedimentary Basin and international exploration and production. Mr. Murphy holds a Bachelor of Science, Geology degree from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta.

CORPORATE CEASE TRADE ORDERS OR BANKRUPTCIES

During the past ten years, none of the current directors and executive officers of PrairieSky is or has been a director, chief executive officer or chief financial officer of any company that: (i) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, while that person was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. Other than disclosed below, none of the directors or executive officers of PrairieSky is as at the date of this AIF, or has been within ten years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Grant Zawalsky and Ms. Margaret McKenzie, each of whom are directors of the Company, were each directors of Endurance Energy Ltd. (*Endurance*), a corporation engaged in the exploration and production of natural gas. Endurance filed for creditor protection under the *Companies Creditors' Arrangement Act* on May 30, 2016. Ms. McKenzie resigned as a director of Endurance on March 31, 2016 and Mr. Zawalsky resigned as a director on November 1, 2016.

Mr. Grant Zawalsky was a director of Zargon Oil and Gas Ltd. (*Zargon*), a corporation engaged in the exploration and production of crude oil and natural gas. Zargon filed for creditor protection under the *Bankruptcy and Insolvency Act* (*BIA*) on September 8, 2020. Mr. Zawalsky resigned as a director on September 8, 2020 concurrent with Zargon filing the Notice of Intention to make a Proposal under the BIA.

PERSONAL BANKRUPTCIES

None of the directors or executive officers of PrairieSky has nor any shareholder holding sufficient number of securities of the Company to affect materially the control of the Company, within the past ten years, 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 the assets of the proposed director.

PENALTIES OR SANCTIONS

No director, executive officer or promoter of PrairieSky, nor any shareholder holding sufficient number of securities of the Company to affect materially the control of the Company, has been subject to any penalties or sanctions imposed by a court, securities regulatory authority or other regular authority or has entered into a settlement agreement with a securities regulatory authority.

Audit Committee

AUDIT COMMITTEE

The full text of the Audit Committee mandate is included in Appendix C of this AIF.

Composition of Audit Committee

PrairieSky's Audit Committee consists of Ms. McKenzie (Chair), Ms. Bellegarde, Mr. Steeves, and Ms. Alderson. All members of the Audit Committee are independent and financially literate as those terms are used under National Instrument 52-110 - *Audit Committees*. See "*Directors and Executive Officers – Board of Directors of PrairieSky*".

Comprehensive Audit Quality Review

The Audit Committee is responsible for recommending the appointment of the external auditors, overseeing and monitoring their qualifications, independence and performance, and assessing the appropriateness of the audit fees. The Audit Committee continually assesses the Company's external auditors. On an annual basis, the Audit Committee reviews audit and non-audit fees, audit quality, independence, tenure of the auditors, and the controls and processes that help ensure the auditor's independence. Every five years, the Audit Committee performs a comprehensive audit quality review which is a broader and more in-depth review. The most recent comprehensive audit quality review was finalized in February 2024 and is further described below.

The Audit Committee completed its comprehensive audit quality review to assess audit quality and independence standards as required by the Committee's mandate for the five years ended December 31, 2023. The comprehensive review was led by the Chair of the Audit Committee with discussion and review by the full Audit Committee. The Audit Committee engaged an external advisor to collect data, conduct interviews and summarize findings in connection with the comprehensive review. The review was prepared in accordance with guidance published by Chartered Professional Accountants Canada, the Institute of Corporate Directors and the Canadian Public Accountability Board. This comprehensive review focused on the following three key factors of audit quality: 1) independence, objectivity and professional skepticism of the auditor; 2) quality of the engagement team and the audit firm; and 3) quality of communications and interaction with the auditor. This review included input from management and the Audit Committee in the form of a series of questions and answers and input from the external auditor, KPMG LLP, in the form of a questionnaire, an analysis of services provided and reports issued over the five-year period, and a series of audit quality indicators that were selected for measurement and review. The documents and data collected were linked to an Audit Quality Indicators

Framework to facilitate the Audit Committee's review and discussion. A consideration of the comprehensive review was to address the possible risk of institutional familiarity resulting from KPMG LLP serving as the external auditor of PrairieSky since 2014. Regulatory requirements in Canada continue to be audit partner rotation every seven years with a five-year cooling off period. Following initial appointment of KPMG LLP in 2014, partner rotation has occurred in 2019 and 2023, well within the Canadian regulatory requirements. The Audit Committee also reviewed the amount of non-audit related fees as a percentage of total fees paid to KPMG LLP over the 5-year period ended December 31, 2023. The only non-audit related services provided by KPMG LLP during the 5-year period related to tax services. On an annual basis, non-audit related fees were de minimis, totaling between 1% and 4% per year of total fees paid to KPMG LLP. Based on this review, the Audit Committee was satisfied that non-audit related fees would not impair KPMG's independence.

The comprehensive review concluded in February 2024, and based on the results of the review, the Audit Committee determined that it was satisfied with the audit quality provided by KPMG LLP and that after considering the regulatory requirements for partner rotations and other independence measures, retaining KPMG LLP is in the best interests of PrairieSky. As a result, at the next annual general meeting of the Company, the Board of Directors intends to recommend the reappointment of KPMG LLP, Chartered Professional Accountants, as external auditors of the Company.

Pre-Approval Policies and Procedures

The Audit Committee has adopted specific policies and procedures for the engagement of non-audit services which are outlined in the Audit Committee mandate in Appendix C to this AIF. The policies and procedures require pre-approval of all non-audit services, including estimated fees, by the Audit Committee or in certain circumstances, the chair or a subcommittee of the Audit Committee. The policies and procedures permit an overrun of no greater than 10% of the fee estimate. The Audit Committee, the chair or a subcommittee of the Audit Committee, as applicable, must pre-approve any costs that exceed such overrun. All audit and non-audit services are reported to the Audit Committee quarterly.

External Auditor Service Fees

	Year Ended December 31, 2023	Year Ended December 31, 2022
Audit Fees(1)	$ 268,303	$ 254,660
Audit-related Fees(2)	-	-
Tax Fees(3)	10,433	8,293
Total	$ 278,736	$ 262,953

Notes:
(1) Audit fees consist of aggregate fees billed and paid for the audit of PrairieSky's annual financial statements, reviews of interim consolidated financial statements for the quarters of 2022 and 2023 fiscal years, or services that are normally provided in connection with statutory and regulatory filings or engagements.
(2) Audit-related fees consist of aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of PrairieSky’s financial statements and are not reported as Audit Fees.
(3) Aggregate fees billed and paid related to tax services.

Conflicts of Interest

Certain of the directors and executive officers of the Company are engaged in, and may continue to be engaged in, other activities in the industries in which the Company operates from time to time. The ABCA provides that in the event that an officer or director is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

Legal Proceedings and Regulatory Actions

As at the date hereof, there are no legal proceedings that PrairieSky is a party to, or that any of PrairieSky's property is the subject of, that is material to PrairieSky, and there are no such material legal proceedings known to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" to PrairieSky if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of PrairieSky's consolidated current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, we have included the amount involved in the other proceedings in computing the percentage.

Interest of Management and Others in Material Transactions

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

There were no material interests, direct or indirect, of any directors or executive officers of PrairieSky, any shareholder who beneficially owns more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Company.

Transfer Agent and Registrar

TSX Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Common Shares.

Material Contracts

Except for contracts entered into in the ordinary course of business, the Company did not enter into any material contracts within the most recently completed financial year, or before the most recently completed financial year but which are still in effect.

Interests of Experts

NAMES OF EXPERTS

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or relating to, the Company's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are KPMG LLP, the Company’s independent external auditors, and GLJ, the Company's independent qualified reserves evaluator.

INTEREST OF EXPERTS

KPMG LLP is the external auditor of the Company and is independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

As at the date hereof, the designated professionals (as defined in NI 51-102) GLJ, beneficially owned, directly or indirectly, less than 1% of our Common Shares.

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

Additional Financial and Other Information

The information contained in this AIF is as of December 31, 2023, unless otherwise indicated. Additional information about the Company may be available on our public website at www.prairiesky.com or on SEDAR+ at www.sedarplus.ca. Additional financial information is provided in PrairieSky's audited annual consolidated financial statements for the period ended December 31, 2023, and the accompanying management's discussion and analysis. Information about remuneration of directors and officers of PrairieSky, principal holders of the Common Shares and securities authorized for issuance under security-based compensation of the Company, will be contained in the Information Circular and Proxy Statement of the Company which relates to the 2024 Annual General Meeting. In addition, the Company generally maintains supporting materials on its website which may assist in reviewing this AIF, including the Company's 2022 Sustainability Report (which contains a discussion of ESG issues).

For copies of the financial statements of the Company and accompanying management's discussion and analysis and the information circular and proxy statement and additional copies of this AIF (in certain circumstances reasonable fees may apply) please contact:

Investor Relations
PrairieSky Royalty Ltd.
Suite 1700, 350 – 7th Avenue S.W.
Calgary, Alberta T2P 3N9
Telephone: 587.293.4000
Fax: 587.293.4001

Appendix A

FORM 51-101F2

INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of PrairieSky Royalty Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2023. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2023, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2023, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	December 31, 2023	Canada	-	1,839,825	-	1,839,825

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

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

GLJ Ltd., Calgary, Alberta, Canada, January 31, 2024

Chad P. Lemke, P. Eng.
Executive Vice President & COO

Appendix B

Form 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

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

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented in Appendix A of this Annual Information Form.

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

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

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

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

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

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

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

(c) the content and filing of this report.

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

(signed) "*Andrew Phillips*"
Andrew Phillips
President & Chief Executive Officer

(signed) "*Pamela Kazeil*"
Pamela Kazeil
Vice-President, Finance & Chief Financial Officer

(signed) "*Sheldon Steeves*"
Sheldon Steeves
Director, Chair of the Reserves Committee

(signed) "*Grant Zawalsky*"
Grant Zawalsky
Director, Member of the Reserves Committee

DATED as of this 12th day of February 2024.

Appendix C

Audit Committee Mandate

Effective: April 11, 2014, amended and restated February 12, 2024

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of PrairieSky Royalty Ltd. (the "**Company**"). Its primary duties and responsibilities are to: review management's identification of principal financial risks and monitor the process to manage such risks; oversee and monitor the integrity of the Company's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting and accounting compliance; oversee audits of the Company's financial statements; oversee and monitor the qualifications, independence and performance of the Company's external auditors; provide an avenue of communication among the external auditors, management and the Board; and report to the Board regularly.

Composition of Committee

The Committee shall consist of not less than three directors as determined by the Board, all of whom shall qualify as independent directors within the meaning attributed to such term in National Instrument 52-110 - Audit Committees (as implemented by the Canadian Securities Administrators and as amended from time to time) ("**NI 52-110**").

All members of the Committee shall be financially literate, within the meaning attributed to such term in NI 52-110, and at least one member shall have accounting or related financial management expertise as the Board interprets such qualification in its business judgment.

Committee members may not, other than in their capacities as members of the Committee, the Board or any other committee of the Board, as applicable, accept directly or indirectly any consulting, advisory or other compensatory fee from the Company or any subsidiary of the Company, or be an "affiliated entity" (within the meaning attributed to such term in NI 52-110) of the Company or any subsidiary of the Company. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Company that are not contingent on continued service should be the only compensation a Committee member receives from the Company.

Committee members will include only duly elected directors of the Company. At the request of the Committee, certain members of the Company's senior management and others may attend Committee meetings on an ad hoc or a regular basis, as required.

Appointment of Committee Members

Members of the Committee shall be appointed or continued as necessary at a meeting of the Board, provided that any member may be removed or replaced at any time by the Board and shall in any event cease to be a member of the Committee upon ceasing to be a member of the Board. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

Chair

The Board shall appoint the Chair of the Committee (the "**Chair**"). If the Chair is unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen by a majority of members of the Committee present at such meeting to preside over the meeting. The items pertaining to the Chair should be read in conjunction with the "Committee Chair" section of the *Chair of Board of Directors and Committee Chair General Guidelines*.

Committee Meetings

The Committee shall meet at least quarterly. The Chair may call additional meetings as required. In addition, a meeting may be called by the Board Chair, the President & Chief Executive Officer, any member of the Committee or the external auditors.

Committee meetings may be held in person, by means of electronic, telephone or other communication facilities as to permit all persons participating in the meeting to hear each other or by combination of any of the foregoing.

At all meetings of the Committee every question will be decided by a majority of the votes cast on the question. In case of an equality of votes, the Chair presiding at any meeting shall not be entitled to a second or casting vote.

Notice of Meeting

Notice of the time and place of each Committee meeting may be given orally, or in writing, or by facsimile, or by electronic means to each member of the Committee at least 48 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Company.

A Committee member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

Quorum

A majority of Committee members, present in person, by electronic, telephone or other communication facilities or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member's presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

Attendance at Meetings

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee. The Committee may, by specific invitation, have other resource persons in attendance.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Chair or by a majority of the members of the Committee.

The Committee shall meet "in-camera" with the external auditors at least quarterly (in connection with the preparation of the annual and quarterly financial statements), and at such other times as the external auditors and the Committee consider appropriate.

The Vice-President, Finance & Chief Financial Officer or any other person holding a similar role in accounting, risk, compliance and/or audit are expected to be available to attend the Committee's meetings or portions thereof, unless otherwise excused from all or part of any such meeting by the Committee Chair.

Minutes

The Committee shall appoint a secretary who need not be a member of the Committee. The secretary shall keep minutes of the meetings of the Committee. Minutes of Committee meetings shall be sent to all Committee members and the external auditors. The full Board shall be kept informed of the Committee's activities by a report following each Committee meeting, unless each Board member who is not also a member of the Committee is in attendance at such Committee meeting.

SPECIFIC RESPONSIBILITIES

Review Procedures

Review and update the Committee's mandate annually, or sooner, where the Committee deems it appropriate to do so. Provide a summary of the Committee's composition and responsibilities in the Company's annual information form or other public disclosure documentation.

Annual Financial Statements

1. Discuss and review with management and the external auditors, the Company's annual audited financial statements and related documents prior to their filing or distribution. Such review to include:

    (a) The annual audited financial statements, including accounting policies and significant management estimates and judgments and any major issues as to the adequacy of the Company's internal controls and disclosure controls and procedures;

    (b) Management's Discussion and Analysis;

    (c) A review of the external auditors' audit examination of the financial statements and their report thereon;

    (d) Review of any significant changes required in the external auditors' audit plan;

    (e) A review of any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors' work or access to required information; and

    (f) A review of other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

2. Following completion of the matters contemplated above and review of consistency of disclosure, recommend approval to the Board of the Company's:

    (a) Year-end audited financial statements; and

    (b) Management's Discussion and Analysis.

Quarterly Financial Statements

3. Review with management and the external auditors and either approve (such approval to include the authorization for their filing or distribution) or formally recommend for approval to the Board, the Company's:

   (a) Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis; and

   (b) Any significant changes to the Company's accounting policies, significant management estimates and judgments.

Other Financial Filings and Public Documents

4. The Committee is to review prospectuses, annual information forms (AIF), business acquisition reports (BARs) and all other public disclosure containing audited or unaudited financial information before release and prior to Board approval.

5. Review and discuss with management financial information, including annual and interim earnings press releases, the use of "pro forma" or non-GAAP financial information and guidance, contained in any filings with the securities regulators or news releases related thereto (or provided to analysts or rating agencies). Consideration should be given as to whether the information is consistent with the information contained in the financial statements of the Company. Such review and discussion should occur before public disclosure and may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Committee must be satisfied that adequate procedures are in place for the review of PrairieSky's disclosure of all other financial information and shall periodically assess the reasonableness of those procedures.

Internal Control Environment

6. Ensure that management provides to the Committee an annual report on the Company's control environment as it pertains to the Company's financial reporting process and controls.

7. Review with the President & Chief Executive Officer, the Vice-President, Finance & Chief Financial Officer and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Company's internal controls and procedures for financial reporting which could adversely affect the Company's ability to record, process, summarize and report financial information required to be disclosed by the Company in the reports that it files or submits under applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that involves management of the Company or other employees who have a significant role in the Company's internal controls and procedures for financial reporting.

8. Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Company.

9. Review management's processes in place to prevent and detect fraud.

10. Review significant findings prepared by the external auditors together with management's responses, if any.

11. Review the audit plans of the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud or other illegal acts. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

Other Review Items

12. Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets.

13. Review all related party transactions between the Company and any officers or directors, including affiliations of any officers or directors as the Committee considers appropriate.

14. Review legal and regulatory matters, including correspondence and filings with regulators and governmental agencies, which may have a material impact on the interim or annual financial statements, related corporate compliance policies, and programs and reports received from regulators or governmental agencies, including but not limited to reporting documents filed under the *Extractive Sector Transparency Measures Act* and the *Fighting Against Forced Labour and Child Labour in Supply Chains Act.*

15. Review policies and practices with respect to risk management, including trading and hedging activities and insurance.

16. Review policies and practices with respect to cyber-security risk management, including but not limited to: (a) assessing best practices from industry associations and recognized information security organizations in relation to the Company's business and operations; and (b) reviewing third party vulnerability and security tests and assessments performed by or on behalf of the Company.

17. In conjunction with the Corporate Governance Committee, review procedures for the receipt, retention and treatment of complaints received by the Company, regarding accounting, internal accounting controls, or auditing matters including confidential, anonymous submissions by employees of the Company, regarding accounting, internal accounting controls, or auditing matters.

18. Meet on a periodic basis separately without management.

External Auditors

19. Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Company. The external auditors shall report directly to the Committee.

20. Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chair or by a majority of the members of the Committee.

21. Obtain and review a report from the external auditors at least annually regarding:

(a) The external auditors' internal quality-control procedures;

(b) Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues; and

(c) Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Company and its affiliates in order to determine the external auditors' independence.

22. Review and evaluate:

(a) The external auditors' performance and the lead partner of the external auditors' team's performance, and make a recommendation to the Board regarding the reappointment of the external auditors at the annual meeting of the Company's shareholders or regarding the discharge of such external auditors and the subsequent nomination of a new external auditor;

(b) The terms of engagement of the external auditors together with their proposed fees;

(c) External audit plans and results; and

(d) Any other related audit engagement matters.

23. Ensure the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

24. Perform a comprehensive audit quality review to assess audit quality and independence standards every five years in accordance with the guidance published by Chartered Professional Accountants Canada, the Institute of Corporate Directors and the Canadian Public Accountability Board.

25. Consider and review with the external auditors and management:

(a) Significant findings during the year and management's responses and follow-up thereto;

(b) Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response;

(c) Any significant disagreements between the external auditors and management; and

(d) Any changes required in the planned scope of their audit plan.

Pre-Approval of Audit and Non-Audit Services

26. Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) for PrairieSky and/or any subsidiaries in advance of the provision of those services by the external auditors (subject to de minimis exceptions for non-audit services described in NI

52-110, the rules and forms under applicable Canadian federal and provincial legislation and regulations, which services are approved by the Committee prior to the completion of the audit).

27. Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

28. Delegate, if the Committee deems necessary or desirable, to the Chair or a subcommittee consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 26 and 27. The decision of the Chair or any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

29. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 26 and 27, so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation of the Committee's responsibilities under applicable Canadian federal and provincial legislation and regulations to management.

30. The Committee shall evidence their pre-approval for services to be provided by the external auditors as follows: (a) in situations where the Chair or a subcommittee pre-approves work under the delegation of authority described in paragraph 28, the Chair or a member of the subcommittee, as applicable, will provide email confirmation of approval of the engagement to the external auditors and the other members of the Audit Committee; and (b) in all other situations, a resolution described in paragraph 28 of the Audit Committee shall be required and confirmation of approval shall be communicated to the external auditors by email.

31. All audit and non-audit services to be provided by the external auditors shall be provided pursuant to an engagement letter that shall: (a) be in writing and signed by the external auditors; (b) specify the particular services to be provided; (c) specify the period in which the services will be performed; (d) specify the estimated total fees to be paid, which, at the conclusion of the service, shall not exceed the estimated total fees pre-approved by the Audit Committee or the Chair or a subcommittee, as applicable, by more than 10%; and (e) include a confirmation by the external auditor that the services are not within a category of services the provision of which would impair their independence under applicable law and Canadian generally accepted accounting standards.

    For clarity, the Audit Committee pre-approval process permits an overrun of fees pertaining to a particular engagement of no greater than 10% of the estimate identified in the associated engagement letter. The intent of the overrun authorization is to ensure on an interim basis only, that services can continue pending a review of the fee estimate, and, if required, further Audit Committee, Chair or subcommittee, as applicable, approval of the overrun. If an overrun is expected to exceed the 10% threshold, as soon as the overrun is identified, the Audit Committee, Chair or subcommittee, as applicable, must be notified and an additional pre-approval obtained prior to the engagement continuing.

Other Matters

32. Review and concur in the appointment, replacement, reassignment, or dismissal of the Vice-President, Finance & Chief Financial Officer.

33. Report Committee actions to the Board with such recommendations, as the Committee may deem appropriate.

34. Conduct or authorize any review or investigation into any matters within the Committee's scope of responsibilities. The Committee shall have unrestricted access to personnel and information and any resources necessary to carry out its responsibility. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and in carrying out of its duties. The Committee shall have the authority to set and pay compensation for any such advisors.

35. The Committee shall review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

36. Perform such other functions as required by law, the Company's articles or bylaws, or the Board.

37. Consider any other matters referred to it by the Board.

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board.