Annual Information Form

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Dated | March 2 | 2022

Quality Assets. Sustainable Dividends.

Freehold
ROYALTIES LTD.

TSX FRU

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Advisories

Cautionary Statement Regarding
Forward-Looking Information and Statements

This Annual Information Form ("**AIF**"), including documents incorporated by reference, contains forward-looking information and statements (collectively "**forward-looking statements**"). These statements, which relate to future events or our future performance, are provided to allow readers to better understand our 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, targeting, intend, could, might, should, believe and similar expressions (including the negatives thereof). These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe 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 statements speak only as of the date of this AIF. We assume no obligation to revise or update these statements except as required pursuant to applicable securities laws.

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

- Freehold Royalties Ltd.'s ("**Freehold**" or the "**Corporation**") strategy with respect to future acquisitions and the possibility that the Board of Directors may vary the strategy in the future;
- the performance characteristics of our oil and natural gas properties;
- the estimated future value of our oil and natural gas reserves;
- projected oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- estimated abandonment and reclamation costs;
- the anticipated benefits of the acquisition of certain U.S. royalty assets and the expectation of multiple year development will occur on the acreage;
- the expectation that Freehold will have minimal future development costs associated with development of its reserves;
- expected timing for development of undeveloped reserves;
- the funding and payment of future dividends;
- the expectations for the funding of capital expenditures;
- the expectation that the September 2021 U.S. Royalty Transaction will add 2,500 boe of average royalty production in 2022 and the expected components of such production;
- the expectation of certain activities to be undertaken by operators in areas in which we have a royalty or working interest;
- the expectation that Freehold's light, medium and heavy crude oil net undeveloped reserves will be developed as commodity pricing permits and the timing thereof;
- the anticipated acreage of unproved properties on which Freehold expects its rights to expire within the next year;

- expectations regarding additional oil or natural gas that may be recovered from certain royalty properties in which we have an interest;
- our tax horizon and taxability;
- expectations regarding the Trans Mountain Pipeline extension, the NGTL System, the IAA, future climate change regulations and regulations regarding indigenous consultation and the resulting effects on Freehold and the industry in general;
- expectations regarding the ability to raise capital and add to reserves through acquisitions and development;
- the performance and characteristics of the oil and natural gas properties in which we have an investment;
- treatment under governmental regulatory regimes and tax laws;
- the expectation that our mineral title lands and gross overriding royalty interests will provide the majority of revenue;
- Freehold's anticipated acquisition strategy and the expectation that such strategy will provide both near and long-term growth in value;
- the expectation that Freehold may acquire additional royalties and other forms of oil and natural gas related assets;
- the expectation that properties to be acquired will be operated by competent third parties;
- the expected components of the purchase price paid by Freehold for newly created royalties;
- the expectation that approximately $1.0 million will be directed towards site reclamation work on previously abandoned wells;
- expectations with respect to income tax payable in Canada and the United States in 2022;
- Freehold's expectations with respect to the treatment, timing and anticipated results/outcome of its proceedings with the CRA; and
- expectations with respect to the timing of Freehold's Annual Meeting of Shareholders and documents relating thereto.

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:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- the effects of the Russian/Ukrainian conflict on commodity prices and the world economy;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of royalty reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- risks related to the environment and changing environmental laws, such as, carbon tax and methane emissions regulations;
- the impact of the continuing COVID-19 pandemic;
- geological, technical, drilling, and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

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 we believe that the assumptions underlying such forward-looking statements are reasonable, we 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 impact of increasing competition;
- the general stability of the economic and political environment in which we have an interest in oil and natural gas properties;
- the timely receipt of any required regulatory approvals;
- our policies with respect to acquisitions and payments of dividends;
- the ability of the Manager to obtain qualified staff, equipment and services in a timely and cost efficient manner;
- drilling results;
- the ability of the operator of the projects that Freehold has an interest in to operate the field in a safe, efficient and effective manner;
- the continued development of the lands in which we have a royalty interest;
- that third parties such as royalty payors, operators of the lands in which we have a working interest and other contractual counterparties will satisfy their obligations as required;
- our ability to obtain financing on acceptable terms;
- field production rates and decline rates;
- the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration;
- the performance and characteristics of the oil and natural gas properties in which we have an interest;
- the timing and costs of pipeline, storage and facility construction and expansion and the ability of the operator of the properties in which we have an interest to secure adequate product transportation;
- future oil and natural gas prices;
- currency, exchange and interest rates;
- the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which we have an interest in oil and natural gas properties; and
- the ability of the operator of the properties in which we have an interest to successfully market its oil and natural gas products. See "*Reserves Data – Significant Factors and Uncertainties*".

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.

Drilling Locations

This Annual Information Form discloses anticipated future drilling or development locations associated with Freehold assets. Certain locations have been identified as booked locations as proved and/or probable reserves have been attributed to such locations in the Trimble Report or Ryder Scott Report. The remaining locations are currently considered unbooked locations. Unbooked locations are generated by internal estimates of Freehold management based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Unbooked locations have been identified by management as an estimation of the multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, historic drilling, production, commodity price assumptions and reserves information. There is no certainty that all unbooked drilling locations will be drilled and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. Freehold has no control on whether any wells will be actually drilled in respect of such unbooked locations. The drilling locations on which wells are actually drilled will ultimately depend upon the capital allocation decisions of royalty payors who have working interests in respect of such drilling locations and a number of other factors including, without limitation, availability of capital, regulatory approvals, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

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**"). We use 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 oil and natural gas reserve information contained in this AIF has been prepared and presented in accordance with National Instrument 51-101. The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this AIF. The estimated future net revenue from the production of the disclosed oil and natural reserves does not represent the fair market value of these reserves.

Glossary of Terms

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

"**1872348**" means 1872348 Alberta Ltd., a corporation incorporated under the ABCA, a wholly-owned subsidiary of Freehold and trustee of FHT.

"**2020 Subscription Receipts**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**2021 Subscription Receipts**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**Acquisitions Opportunities Agreement**" means the acquisitions opportunities agreement effective March 1, 2021 among Rife, Freehold, the Manager and Canpar.

"**Board of Directors**" means the board of directors of Freehold.

"**Canpar**" means Canpar Holdings Ltd., a wholly-owned subsidiary of the CN Pension Trust Funds.

"**CN Pension Trust Funds**" means the pension trust funds for employees of Canadian National Railway Company.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

"**Common Shares**" means the common shares of Freehold.

"**COVID-19**" means the disease caused by severe acute respiratory syndrome coronavirus 2, first identified in December 2019.

"**CRA**" means the Canada Revenue Agency.

"**December 2020 Financing**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**December 2020 Offering**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**Deferred Share Unit Plan**" means the deferred share unit plan for non-management directors of Freehold whereby fully vested Deferred Share Units are granted annually and dividends to Shareholders declared by Freehold prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of dividends.

"**Deferred Share Units**" means our deferred share units issued pursuant to the Deferred Share Unit Plan that are redeemable for Common Shares any time after the retirement of a member of the Board of Directors.

"**FHT**" means Freehold Holdings Trust, a commercial trust formed under the laws of Alberta.

"**Freehold**", "**us**", "**we**", "**our**" or the "**Corporation**" means Freehold Royalties Ltd., a corporation amalgamated under the ABCA. All references to "Freehold", "us", "we", "our" or the "Corporation", unless the context otherwise requires, are references to Freehold Royalties Ltd., its predecessors, its subsidiaries and partnerships.

"**Freehold (USA)**" means Freehold Royalties (USA) Inc., a corporation formed under the laws of the state of Delaware, USA.

"**GORR**" means gross overriding royalty.

"**Governance Agreement**" means the governance agreement between the Manager and Freehold dated as of December 31, 2010.

"**Gross**" or "**gross**" means:

- in relation to production and reserves, our working interest (operated and non-operated) share before deduction of royalties and without including our royalty interests;
- in relation to wells, the total number of wells in which we have an interest; and
- in relation to properties, the total number of properties in which we have an interest.

"**January 2021 U.S. Royalty Assets**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**January 2021 U.S. Royalty Transaction**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2020*".

"**Management Agreement**" means the fourth amended and restated agreement dated November 9, 2015 among the Manager, Rife, Freehold, FHT and the Partnership, which amended and restated the Original Management Agreement, pursuant to which the Manager provides management services to Freehold, FHT and the Partnership.

"**Management Fee**" means the fee payable to the Manager pursuant to the Management Agreement.

"**Manager**" means Rife Resources Management Ltd., a wholly-owned subsidiary of Rife.

"**Net**" or "**net**" means:

- in relation to production and reserves, our working interest (operated and non-operated) share after deduction of royalty obligations, plus our royalty interests;
- in relation to wells, except as otherwise provided herein, the number of wells obtained by aggregating our working interest in each of its gross wells; and
- in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

"**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*.

"**Original Management Agreement**" means the management agreement dated November 25, 1996 among the Manager, Freehold Resources Ltd., and Freehold Royalty Trust, as amended and restated by the first amended and restated management agreement dated May 10, 2006 among the Manager, Freehold Resources Ltd., and Freehold Royalty Trust, as amended and restated by the second amended and restated management agreement dated January 1, 2011 among the Manager, Freehold, Freehold Resources Ltd., and the Partnership, as amended and restated by the third amended and restated management agreement dated January 23, 2015 among the Manager, Freehold, FHT, and the Partnership.

"**Partnership**" means Freehold Royalties Partnership, a general partnership formed under the laws of Alberta.

"**Preferred Shares**" means the preferred shares of Freehold.

"**Proved**" and "**probable**" reserves have the meanings given to those terms under "*Reserves Data – Disclosure of Reserves Data*".

"**Reassessments**" has the meaning ascribed thereto under "*Other Oil and Gas Information – Tax Horizon*".

"**Rife**" means Rife Resources Ltd., a wholly-owned subsidiary of the CN Pension Trust Funds.

"**Royalty Income**" means our income from our royalties in oil, natural gas, NGL and potash resources.

"**Royalty Lands**" means our lands from which we derive Royalty Income.

"**Ryder Scott**" means RSC Group, Inc., independent qualified reserves evaluators of Calgary, Alberta.

"**Ryder Scott Report**" means the report dated February 24, 2022 prepared by RSC Group, Inc., evaluating our U.S. oil, natural gas and natural gas liquids reserves as at December 31, 2021.

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

"**September 2021 Offering**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**September 2021 U.S. Royalty Assets**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**September 2021 U.S. Royalty Transaction**" has the meaning ascribed thereto under "*General Development of the Business – Year Ended December 31, 2021*".

"**Shareholders**" means the holders from time to time of Common Shares.

"**Tax Act**" means the *Income Tax Act* (Canada) and the regulations thereunder.

"**Trimble**" means Trimble Engineering Associates Ltd., independent qualified reserves evaluators of Calgary, Alberta.

"**Trimble Report**" means the report dated February 9, 2022 prepared by Trimble, evaluating our Canadian oil, natural gas, natural gas liquids, and sulphur reserves as at December 31, 2021.

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

"**USA**", "**U.S.**" or "**United States**" means the United States of America.

Abbreviations

AECO	reference pricing point for natural gas at a natural gas storage facility near the Alberta-Saskatchewan border
API	American Petroleum Institute
°API	the measure of the density of liquid petroleum products derived from a specific gravity
bbl and bbls	barrel and barrels, respectively, each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mbbls	one thousand barrels
Mboe	one thousand barrels of oil equivalent
MMbbls	one million barrels
MMboe	one million barrels of oil equivalent
MMBtu	one million British Thermal Units
Mcf	one thousand cubic feet
Mcf/d	one thousand cubic feet per day
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
NGL	natural gas liquids
NYMEX	the New York Mercantile Exchange, a U.S. based commodity futures market
WTI	West Texas Intermediate

Conversion Factors

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.471

All dollar amounts set forth in this AIF are in Canadian dollars, except where otherwise indicated.

Corporate Structure

General

Freehold is a dividend paying oil and gas corporation based in Calgary, which, directly or indirectly, acquired all of the assets and assumed all of the liabilities of Freehold Royalty Trust pursuant to a plan of arrangement completed on January 1, 2011.

On January 23, 2015, Freehold completed a restructuring pursuant to which it amalgamated first with its wholly-owned subsidiary, 1851328 Alberta Ltd., and subsequently with another wholly owned subsidiary, Freehold Resources Ltd. The articles and by-laws of Freehold were not amended as a result of the amalgamation.

Freehold enables its Shareholders to participate in the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold, FHT, the Partnership and Freehold (USA). The head, principal and registered office of Freehold is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

Rife Resources Management Ltd.

The Manager was incorporated under the *Corporations Act* (Ontario) on March 5, 1968 under the name "75-89 Gosford Limited" and continued under the *Canada Business Corporations Act* on April 20, 1979. The Manager changed its name to "Rife Resources Management Ltd." on October 1, 1996. Pursuant to the Management Agreement, Freehold, FHT and the Partnership retained the Manager for the purposes of identifying, evaluating and assisting with the acquisition, disposition and ongoing management and administration of the royalties, working interest properties and other oil, natural gas and potash resources held by Freehold, FHT and the Partnership. The head, principal and registered office of the Manager is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

Pursuant to an agreement between Rife and the Manager, Rife provides the Manager, which is a wholly-owned subsidiary of Rife, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to Freehold, FHT and the Partnership on a cost recovery basis. Freehold benefits from the fact that Rife has been in operation for more than 35 years and many of Rife's personnel have extensive experience managing the assets underlying Freehold's royalty and working interest assets. In addition, Rife manages two private entities that are also engaged in oil and gas operations and as a result Rife has assembled a diversified and experienced staff to manage the assets of Freehold. These organizational and synergistic benefits are advantageous to Shareholders.

Under the terms of the Acquisitions Opportunities Agreement, Rife ensures that Freehold receives priority to consider acquisition opportunities for royalty interests in oil and gas properties and in alternative minerals (non-oil and gas) properties except in the case of alternative minerals opportunities that are related to an existing property of Rife or Canpar. The Acquisitions Opportunities Agreement also sets out a framework that allows each of Freehold and Rife an opportunity to elect to participate in acquisition opportunities for royalty interests in alternative minerals (non-oil and gas) with the percentage of each entities' participation dependent on whether the property relates to an existing property of Rife, Canpar or Freehold.

In addition, the Management Fee paid to the Manager is paid in Common Shares, which the Board of Directors believes aligns the interests of the Manager with the interests of the Shareholders. Under the terms of the Management Agreement, the Common Shares issuable as payment of the Management Fee will be gradually reduced over the next several years. See "*The Manager – Compensation – Management Fee*". Based on these factors, the Board of Directors believes that maintaining Freehold's relationship with the Manager is in the best interests of Freehold.

Pursuant to the Governance Agreement, the Manager is entitled to nominate for election two individuals as directors of Freehold provided that the Manager and its affiliates, including the CN Pension Trust Funds, hold 10% or more of the issued and outstanding Common Shares. If the Manager and its affiliates hold less than 10% of the issued and outstanding Common Shares, the Manager will have the right to nominate for election one individual as a director of Freehold. If the individuals nominated by the Manager fail to get elected or if the Manager ceases to hold any Common Shares (in which case the Manager will not have the right to nominate any individuals as directors of Freehold) but continues to act as manager of Freehold pursuant to the Management Agreement, the Governance Agreement will provide the Manager with the right to have an observer present at all meetings of directors of Freehold. The CN Pension Trust Funds currently holds, directly or indirectly, approximately 18.08% of the outstanding Common Shares and as a result, has the right to nominate two individuals as directors of Freehold.

Freehold Holdings Trust

FHT is a commercial trust formed under the laws of Alberta. All of the issued and outstanding trust units of FHT are held by Freehold and 1872348 is the trustee of FHT. The head office of FHT is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

1872348 Alberta Ltd.

All of the issued and outstanding shares of 1872348 are held by Freehold. The head, principal and registered office of 1872348 is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

Freehold Royalties Partnership

The Partnership is a general partnership formed under the laws of Alberta. On December 13, 2010, the Partnership changed its name from "Petrovera Resources" to "Freehold Royalties Partnership". Freehold and FHT are the general partners of the Partnership. Freehold is the managing partner of the Partnership. The head office of the Partnership is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8.

Freehold Royalties (USA) Inc.

Freehold (USA) is a corporation formed under the laws of the state of Delaware, USA. All of the issued and outstanding shares of Freehold (USA) are held by Freehold. The head and principal office of Freehold (USA) is located at Suite 1000, 517 – 10th Avenue SW, Calgary, Alberta, T2R 0A8. The registered office of Freehold (USA) is located at 251 Little Falls Drive, Wilmington, Delaware, USA 19808.

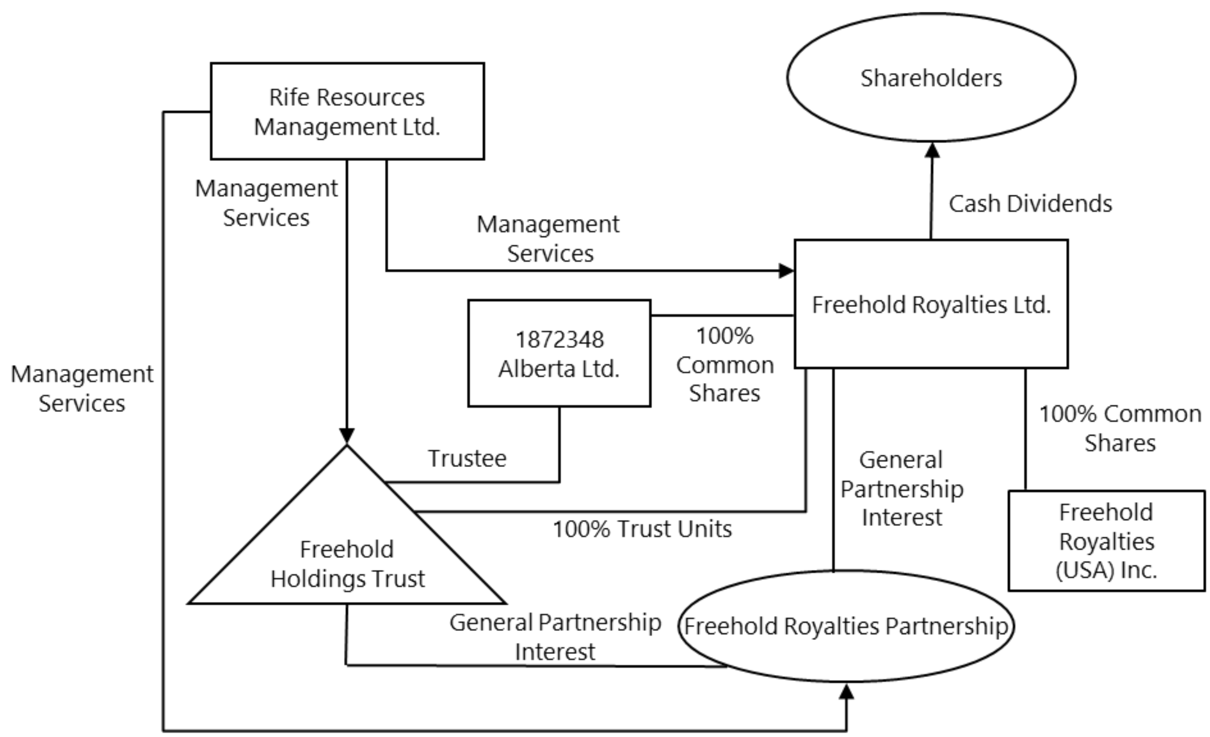
Structure of the Corporation

The following table provides the name, the percentage of voting securities owned by Freehold and the jurisdiction of incorporation, continuance or formation of our subsidiaries and partnerships, either direct or indirect, as at the date hereof.

	Percentage of Voting Securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Freehold Royalties Partnership	100%	General Partnership	Alberta
Freehold Holdings Trust	100%	Commercial Trust	Alberta
1872348 Alberta Ltd.	100%	Corporation	Alberta
Freehold Royalties (USA) Inc.	100%	Corporation	Delaware

Organizational Structure of the Corporation

The following diagram sets forth the organizational structure of Freehold.



General Development of the Business

The following is a summary description of the development of our business since January 1, 2019.

Year Ended December 31, 2019

In June 2019, Freehold closed a $30.0 million acquisition of a gross overriding royalty with drilling commitments on the part of the vendor on certain light and medium oil reservoirs in central and northern Alberta and southwest Saskatchewan. Production (primarily oil) associated with the acquired assets after closing the transaction was 250 boe/d.

In July 2019, Freehold closed a US$9.8 million acquisition of certain royalty assets located in North Dakota. In addition, we completed the acquisition of a further 230 net mineral acres in North Dakota for total cash consideration of US$1.3 million. Production (primarily oil) associated with Freehold's U.S. assets after closing these transactions was 115 boe/d.

Year Ended December 31, 2020

On November 24, 2020 Freehold entered into a definitive agreement with a private seller to acquire certain mineral title and royalty interest assets in the United States (the "**January 2021 U.S. Royalty Assets**") for an aggregate purchase price of US$58 million (the "**January 2021 U.S. Royalty Transaction**").

In connection with the January 2021 U.S. Royalty Transaction, on December 9, 2020, Freehold closed a bought deal offering of 9,856,000 subscription receipts ("**2020 Subscription Receipts**") of the Corporation at a price of $4.80 per 2020 Subscription Receipt for gross proceeds of approximately $47 million (the "**December 2020 Offering**"). Concurrent with the closing of the December 2020 Offering, CN Pension Trust Funds indirectly purchased 2,791,667 2020 Subscription Receipts at a price of $4.80 per 2020 Subscription Receipt for gross proceeds of approximately $13.4 million on a non-brokered private placement basis (together with the December 2020 Offering, the "**December 2020 Financing**").

Year Ended December 31, 2021

The January 2021 U.S. Royalty Transaction closed on January 5, 2021 and the net proceeds of the December 2020 Financing were released from escrow to Freehold to partially fund the purchase price for the January 2021 U.S. Royalty Assets, with the remainder of the purchase price funded by drawing on existing credit facilities. In addition, as a result of and on closing of the January 2021 U.S. Royalty Transaction and in accordance with the terms of the 2020 Subscription Receipts, each 2020 Subscription Receipt was exchanged for one Common Share.

The January 2021 U.S. Royalty Transaction added exposure to approximately 400,000 gross drilling unit acres to Freehold's portfolio with minimal exposure to U.S. Federal lands (less than 4% of January 2021 U.S. Royalty Assets acreage). As a result of the January 2021 U.S. Royalty Transaction, Freehold acquired a royalty interest in approximately 1,800 producing wells. The January 2021 U.S. Royalty Assets include mineral title and royalty interests in eight states and 12 oil and natural gas basins that added 1,150 boe/d of production in 2021. The majority of the value of the January 2021 U.S. Royalty Assets is concentrated in the prolific Permian (Delaware and Midland) and Eagle Ford basins in Texas.

In July 2021, Freehold closed the acquisition of certain U.S royalty properties for US$15.9 million ($19.5 million). This acquisition included exposure to the Eagle Ford, Delaware and Midland basins in Texas, expanding Freehold's North American royalty footprint. The acquired royalty assets provide exposure to a strong suite of exploration and production companies with multiple year development plans expected on the acreage.

On September 8, 2021, Freehold entered into a definitive agreement with a private seller to acquire certain royalty interest assets in the United States (the "**September 2021 U.S. Royalty Assets**") for an aggregate purchase price of US$180 million less customary adjustments (the "**September 2021 U.S. Royalty Transaction**"). The September 2021 U.S. Royalty Assets consist of a concentrated royalty land position in the core of the Eagle Ford oil basin in Texas across approximately 92,000 gross drilling unit acres with an average royalty rate of approximately 1.8%. The September 2021 U.S. Royalty Transaction is expected to add 2,500 boe/d (approximately 50% light oil, 23% natural gas liquids and 27% natural gas) of average royalty production in 2022.

In connection with the September 2021 U.S. Royalty Transaction, on September 22, 2021, Freehold closed a bought deal offering of 16,580,000 subscription receipts ("**2021 Subscription Receipts**") of the Corporation at a price of $9.05 per 2021 Subscription Receipt for gross proceeds of approximately $150 million (the "**September 2021 Offering**"). The September 2021 U.S. Royalty Transaction closed on September 24, 2021 and the net proceeds of the September 2021 Offering were released from escrow to Freehold to partially fund the purchase price for the September 2021 U.S. Royalty Assets, with the remainder of the purchase price funded by drawing on existing credit facilities. In addition, as a result of and on closing of the September 2021 U.S. Royalty Transaction and in accordance with the terms of the 2021 Subscription Receipts, each 2021 Subscription Receipt was exchanged for one Common Share.

In October 2021, Freehold acquired concentrated, high quality U.S. royalty assets in Texas for US$53.3 million ($67.5 million). The acquired assets are concentrated in the Midland basin in Texas.

Freehold also closed three additional U.S. royalty transactions and one Canadian royalty transaction in 2021, further complementing our positions in the Bakken and Permian basins in the U.S. and Clearwater play in Canada. Total consideration associated with these additional U.S. transactions was approximately US$3.7 million ($4.9 million) and $5.8 million for the Canadian transaction.

Significant Acquisitions

During the year ended December 31, 2021, Freehold did not complete any acquisitions that would be considered significant pursuant to NI 51-102.

Business of the Corporation

Overview

Freehold is an Alberta-based, dividend-paying corporation with a focus on royalty assets. Freehold manages one of the largest non-government portfolios of oil and natural gas royalties in Canada with an expanding land base in the United States, uniquely positioning it as a North American royalty company. Freehold's total land holdings encompass approximately 6.2 million gross acres in Canada and Freehold has exposure to approximately 765,000 gross drilling unit acres in the U.S., collectively greater than 99% of which are royalty lands. Freehold's Canadian mineral title lands (including royalty assumption lands), which it owns in perpetuity, cover approximately 1.1 million acres and Freehold also has gross overriding royalty and other interests in approximately 5.1 million acres. Freehold's U.S. acreage is comprised of more than 80% mineral title lands.

Freehold has royalty interests in more than 15,000 producing wells and 350 units spanning five provinces and eight states and receives royalty income from over 350 industry operators throughout North America. Freehold's revenues also include potash, bonus consideration and lease rental streams that diversify its royalty revenue portfolio. Freehold's North American land base lowers its risk, and as a royalty owner, it benefits from the drilling activity of others without any capital investments.

Royalties offer the benefit of sharing in production, without exposure to the capital, operating and environmental costs associated with oil, natural gas, and potash production. As a royalty interest owner, Freehold does not pay any of the capital costs to drill and equip the wells for production on its properties, nor does it incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. All of these costs are paid by others. Freehold receives royalty income from gross production revenue (revenue before any royalty expenses and operating costs are deducted).

Management Policies and Acquisition Strategy

The Manager manages Freehold, FHT and the Partnership in accordance with the Management Agreement. The Manager utilizes the extensive experience of Rife staff and employs prudent oil and gas business practices to increase the assets of Freehold through the acquisition of royalty interests in oil and natural gas properties.

Freehold may, directly or indirectly through its subsidiaries and partnerships, acquire additional royalties and other forms of oil and natural gas related assets that are primarily of a low risk nature. Properties to be acquired are operated by competent third parties.

Freehold's acquisition strategy targets individual properties, or groups of properties with a focus on royalty interests, to provide both near and long-term growth in value. The key criteria are:

- quality assets;
- attractive returns;
- acceptable risk profile;

- assets operated by companies with acceptable environmental, social and governance practices and stewardship; and
- long economic life.

These criteria serve as guidelines for the Manager on presenting acquisitions for approval by the Board of Directors. The Board of Directors may vary these criteria for any particular acquisition based on the Manager's recommendations and consideration of the qualitative aspects of the subject properties.

The acquisition of additional royalties by Freehold includes existing contractual royalties and newly created royalties. With respect to new royalties, the purchase price paid by Freehold may include two components: an amount paid at closing for a royalty on existing production and an amount paid towards the drilling of a predetermined number of future wells, which may be paid on completion of a specific operational event.

Environmental and Sustainability Oversight

As a royalty owner, Freehold does not directly operate any of our royalty assets. Royalty owners are not generally responsible for operating or capital costs, or environmental or reclamation liabilities. The projects on which we receive royalty revenue are owned and operated by independent oil and gas companies. Our royalty payors include some of the largest and most recognized oil and gas companies in the Canadian and United States oil and gas industry. These companies are required to operate in ethical, safe and environmentally responsible manner in accordance with the Canadian and United States regulatory framework.

Freehold also owns working interests in oil and natural gas properties. Our working interest assets represented less than 1% of our total production in 2021. We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of our working interest properties upon abandonment. Environment, health and safety falls under the responsibility of Rife as manager of Freehold's assets. Rife has a comprehensive program that includes policies and procedures designed to protect the environment and the health and safety of its employees, contractors, and the public. Rife assesses Freehold's environmental, health and safety liabilities through pre-acquisition assessments, periodic assessments, and audits. Environmental, health and safety exposures are tracked and addressed with short and long-term initiatives.

Freehold is committed to conducting our business in a manner that respects the environment and minimizes the impact that our operations may have on the quality of the air, land and water that surround us. We have an active well abandonment and site reclamation program for our minor working interest assets that ensures wells and facilities are decommissioned and abandoned at the end of their economic life. This proactive abandonment program is designed to mitigate any potential public or environmental risks and to maintain compliance with regulatory requirements. In 2021, less than $1.0 million was directed toward abandonment and reclamation activities, with the focus being on site restoration for previously abandoned wells. For 2022, it is expected that approximately $1.0 million will be directed toward site reclamation work on previously abandoned wells.

A detailed description of Freehold's corporate reporting initiatives and a discussion of environmental, social and governance issues are contained in Freehold's 2019 Environmental, Social and Governance Report, which can be found on Freehold's website at www.freeholdroyalties.com but is not to be considered part of this AIF.

Reserves Data

Our statement of reserves data and other oil and natural gas information is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2021.

In accordance with the requirements of NI 51-101, the Reports on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 and the Report of Management and Directors on Reserves Data and Other Information in Form 51-101F3 are attached as Appendices A and B, respectively.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon evaluations by our independent qualified reserves evaluators, Trimble and Ryder Scott. Both the Trimble Report and the Ryder Scott Report have an effective date of December 31, 2021. The Trimble Report has a preparation date of February 9, 2022 and the Ryder Scott has a preparation date of February 24, 2022.

The Reserves Data summarizes the crude oil, natural gas and natural gas liquids of Freehold and the net present values of future net revenue for these reserves using forecast prices and costs. Trimble also evaluated certain sulphur reserves of Freehold; however, as such sulphur reserves are immaterial to Freehold they have not been presented herein. The Trimble Report and the Ryder Scott Report have been prepared in accordance with NI 51-101 and the standards and reserves definitions contained in the COGE Handbook. Information not required by NI 51-101 has been presented to provide continuity and additional information that we believe is important to the readers of this information. Freehold engaged Trimble and Ryder Scott to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Freehold's reserves as at December 31, 2021 were located in Canada and the United States and, specifically, in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, and Ontario in Canada and in the states of Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas and Wyoming in the United States. Trimble evaluated the Corporation's Canadian assets and Ryder Scott evaluated the Corporation's United States assets.

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

SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS(1)(2)

CANADA

	Light and Medium Oil		Tight Oil		Heavy Oil	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)
Proved						
Developed producing	-	3,590	-	599	-	2,139
Developed non-producing	-	-	-	-	-	8
Undeveloped	-	1,150	-	177	-	413
Total proved	-	4,740	-	776	-	2,560
Probable	-	4,325	-	339	-	955
Total proved plus probable	-	9,064	-	1,115	-	3,516

	Conventional Natural Gas		Coal Bed Methane		Shale Gas	
Reserves Category	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
Proved						
Developed producing	710	44,604	-	1,407	-	1,180
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,724	-	-	-	964
Total proved	710	46,327	-	1,407	-	2,145
Probable	257	19,235	-	266	-	982
Total proved plus probable	966	65,564	-	1,673	-	3,127

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
Proved				
Developed producing	12	1,555	130	15,748
Developed non-producing	-	-	-	8
Undeveloped	-	101	-	2,289
Total proved	12	1,656	130	18,045
Probable	3	713	46	9,746
Total proved plus probable	16	2,370	177	27,792

UNITED STATES

	Tight Oil		Shale Gas		Natural Gas Liquids	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
Proved						
Developed producing	-	3,988	-	11,465	-	1,236
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	297	-	1,042	-	98
Total proved	-	4,285	-	12,506	-	1,334
Probable	-	8,487	-	21,447	-	2,255
Total proved plus probable	-	12,772	-	33,954	-	3,589

Reserves Category	Total Oil Equivalent Gross (Mboe)	Net (Mboe)
Proved		
Developed producing	-	7,135
Developed non-producing	-	-
Undeveloped	-	568
Total proved	-	7,703
Probable	-	14,317
Total proved plus probable	-	22,020

TOTAL

	Light and Medium Oil		Tight Oil		Heavy Oil	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)
Proved						
Developed producing	-	3,590	-	4,587	-	2,139
Developed non-producing	-	-	-	-	-	8
Undeveloped	-	1,150	-	474	-	413
Total proved	-	4,740	-	5,061	-	2,560
Probable	-	4,325	-	8,826	-	955
Total proved plus probable	-	9,064	-	13,887	-	3,516

	Conventional Natural Gas		Coal Bed Methane		Shale Gas	
Reserves Category	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
Proved						
Developed producing	710	44,604	-	1,407	-	12,645
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,724	-	-	-	2,006
Total proved	710	46,327	-	1,407	-	14,651
Probable	257	19,235	-	266	-	22,429
Total proved plus probable	966	65,564	-	1,673	-	37,081

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
Proved				
Developed producing	12	2,791	130	22,883
Developed non-producing	-	-	-	8
Undeveloped	-	199	-	2,857
Total proved	12	2,990	130	25,748
Probable	3	2,968	46	24,063
Total proved plus probable	16	5,959	177	49,812

(1) Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include royalties receivable. Net reserves are comprised of working interests minus royalties payable plus royalties receivable. The majority of our assets are royalty interests. This causes our gross reserves to be lower than our net reserves and may hinder an investor's ability to compare our reserves with others in our industry.

(2) Columns may not add due to rounding.

SUMMARY OF
NET PRESENT VALUES
OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS[(1)(2)]

CANADA	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	662,381	511,344	423,933	366,321	325,147
Developed non-producing	(7,823)	(5,445)	(4,056)	(3,175)	(2,582)
Undeveloped	146,978	113,461	92,698	78,040	67,087
Total proved	801,536	619,360	512,575	441,186	389,652
Probable	580,662	349,312	233,465	167,152	125,838
Total proved plus probable	1,382,199	968,672	746,041	608,337	515,489

CANADA	After Income Taxes[(3)], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	636,622	488,625	403,664	348,058	308,548
Developed non-producing	(6,887)	(4,664)	(3,394)	(2,605)	(2,085)
Undeveloped	114,933	87,046	70,459	58,979	50,505
Total proved	744,668	571,007	470,729	404,432	356,968
Probable	442,268	263,762	175,459	125,301	94,204
Total proved plus probable	1,186,936	834,769	646,187	529,734	451,173

UNITED STATES	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	440,060	301,249	233,109	193,413	167,460
Developed non-producing	-	-	-	-	-
Undeveloped	32,053	24,985	21,043	18,510	16,710
Total proved	472,113	326,233	254,152	211,923	184,170
Probable	982,177	560,909	382,544	285,478	224,398
Total proved plus probable	1,454,290	887,142	636,696	497,401	408,568

UNITED STATES	After Income Taxes[(3)], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	417,752	289,364	225,460	187,854	163,089
Developed non-producing	-	-	-	-	-
Undeveloped	24,919	19,862	16,958	15,049	13,666
Total proved	442,671	309,226	242,418	202,903	176,755
Probable	767,632	431,000	289,158	212,360	164,283
Total proved plus probable	1,210,303	740,226	531,576	415,262	341,038

TOTAL	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	1,102,441	812,593	657,042	559,734	492,607
Developed non-producing	(7,823)	(5,445)	(4,056)	(3,174)	(2,582)
Undeveloped	179,031	138,446	113,741	96,550	83,797
Total proved	1,273,649	945,593	766,727	653,109	573,822
Probable	1,562,839	910,221	616,009	452,630	350,236
Total proved plus probable	2,836,489	1,855,814	1,382,737	1,105,738	924,057

TOTAL	After Income Taxes(3), Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	1,054,374	777,989	629,124	535,912	471,637
Developed non-producing	(6,887)	(4,664)	(3,394)	(2,605)	(2,085)
Undeveloped	139,852	106,908	87,417	74,028	64,171
Total proved	1,187,339	880,233	713,147	607,335	533,723
Probable	1,209,900	694,762	464,617	337,661	258,487
Total proved plus probable	2,397,239	1,574,995	1,177,764	944,997	792,211

(1) Columns may not add due to rounding.

(2) Estimates of future net revenue reflect a deduction for estimated operating costs and abandonment, decommissioning and reclamation costs for all wells (both existing and undrilled and active and inactive wells) whether or not such wells have been attributed reserves as well as for pipelines and facilities. See "*Other Oil and Gas Information – Environmental Obligations – Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs*".

(3) Based on the inclusion of $615,399,000 of tax pools for Canada and $356,975,000 of tax pools for the United States. See "*Other Oil and Gas Information – Tax Horizon*".

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS[1]

	Proved Reserves		
($000s)	Canada	United States	Total
Royalty Income	824,662	528,150	1,352,812
Revenue from working interest properties	2,966	-	2,966
Royalty expense	(255)	(38,251)[3]	(38,506)
Operating costs	(20,454)	(17,786)[4]	(38,240)
Development costs	-	-	-
Abandonment and reclamation costs[2]	(5,382)	-	(5,382)
Future net revenue before income taxes	801,536	472,113	1,273,649
Future income taxes	(56,869)	(29,442)	(86,311)
Future net revenue after income taxes	744,668	442,671	1,187,339

	Proved Plus Probable Reserves		
($000s)	Canada	United States	Total
Royalty Income	1,411,795	1,619,101	3,030,896
Revenue from working interest properties	4,073	-	4,073
Royalty expense	(310)	(117,143)[3]	(117,453)
Operating costs	(27,971)	(47,668)[4]	(75,639)
Development costs	-	-	-
Abandonment and reclamation costs[2]	(5,388)	-	(5,388)
Future net revenue before income taxes	1,382,199	1,454,290	2,836,489
Future income taxes	(195,263)	(243,987)	(439,250)
Future net revenue after income taxes	1,186,936	1,210,303	2,397,239

(1) Columns may not add due to rounding.

(2) Estimates of future net revenue reflect a deduction for estimated operating costs and abandonment, decommissioning and reclamation costs for all wells (both existing and undrilled and active and inactive wells) whether or not such wells have been attributed reserves as well as for pipelines and facilities. See "*Other Oil and Gas Information – Environmental Obligations – Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs*".

(3) Represents Severance Taxes, which are taxes imposed on the removal of natural resources within a taxing jurisdiction. The applicable severance tax is specific to the law of the State in which operations take place. The severance tax is levied at a percentage of market value of the hydrocarbon product or at a unit value of the hydrocarbon product.

(4) Represents Processing Fees which are those post production fees payable by the owner of the hydrocarbon reserves to make the hydrocarbon product marketable. Royalty owners are responsible for their applicable fees.

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2021
FORECAST PRICES AND COSTS(1)(2)(3)

CANADA

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value
		($000s)	($)
Proved	Light and Medium Oil (including solution gas and by-products)	247,404	52.20/bbl
	Tight Oil (including solution gas and other by-products)	42,403	54.66/bbl
	Heavy Crude Oil (including solution gas and other by-products)	114,719	44.81/bbl
	Conventional Natural Gas (including by-products)	106,330	2.62/Mcf
	Coal Bed Methane (including by-products)	2,128	1.51/Mcf
	Shale Gas (including by-products)	4,063	1.89/Mcf
	Total Proved	512,575	28.41/boe
Proved plus probable	Light and Medium Oil (including solution gas and by-products)	415,373	45.82/bbl
	Tight Oil (including solution gas and other by-products)	54,975	49.32/bbl
	Heavy Crude Oil (including solution gas and other by-products)	142,939	40.66/bbl
	Conventional Natural Gas (including by-products)	129,852	2.37/Mcf
	Coal Bed Methane (including by-products)	2,341	1.40/Mcf
	Shale Gas (including by-products)	5,032	1.61/Mcf
	Total Proved Plus Probable	746,041	26.84/boe

UNITED STATES

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value
		($000s)	($)
Proved	Tight Oil (including solution gas and other by-products)	204,942	55.24/bbl
	Shale Gas (including by-products)	49,210	8.05/Mcf
	Total Proved	254,152	32.99/boe
Proved plus probable	Tight Oil (including solution gas and other by-products)	572,825	47.71/bbl
	Shale Gas (including by-products)	63,871	5.15/Mcf
	Total Proved Plus Probable	636,696	28.91/boe

TOTAL

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	Unit Value
		($000s)	($)
Proved	Light and Medium Oil (including solution gas and by-products)	247,404	52.20/bbl
	Tight Oil (including solution gas and other by-products)	247,345	55.14/bbl
	Heavy Crude Oil (including solution gas and other by-products)	114,719	44.81/bbl
	Conventional Natural Gas (including by-products)	106,330	2.62/Mcf
	Coal Bed Methane (including by-products)	2,128	1.51/Mcf
	Shale Gas (including by-products)	53,273	6.45/Mcf
	Total Proved	766,727	29.78/boe
Proved plus probable	Light and Medium Oil (including solution gas and by-products)	415,373	45.82/bbl
	Tight Oil (including solution gas and other by-products)	627,800	47.84/bbl
	Heavy Crude Oil (including solution gas and other by-products)	142,939	40.66/bbl
	Conventional Natural Gas (including by-products)	129,852	2.37/Mcf
	Coal Bed Methane (including by-products)	2,341	1.40/Mcf
	Shale Gas (including by-products)	68,903	4.44/Mcf
	Total Proved Plus Probable	1,382,737	27.76/boe

(1) Columns may not add due to rounding.
(2) The Unit Value is calculated by dividing the discounted Future Net Revenue by the net reserves for the principal product of the Product Type.
(3) For the purposes of calculating future net revenue by product type, operating cost expense, plus abandonment, decommissioning and reclamation capital costs totalling $4,471,200 on a discounted basis in respect of both the proved reserves and proved plus probable reserves categories have been excluded as such costs are related to wells or facilities that have not been attributed reserves and therefore have not been allocated by product type. As such, the columns do not equal the Total Proved and the Total Proved plus Probable future net revenue as a result of such costs being excluded. See "*Other Oil and Gas Information – Environmental Obligations – Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs*".

Definitions and Other Notes

Columns may not add due to rounding.

The oil, natural gas and natural gas liquids reserves estimates presented in the Trimble Report and the Ryder Scott Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

Reserve Categories

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

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

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

(a) 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.

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

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

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

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

    (i) 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.

    (ii) 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.

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

Levels of Certainty for Reported Reserves

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

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

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

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

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

Forecast Prices and Costs

Forecast prices and costs are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Freehold is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Oil and natural gas benchmark reference pricing, inflation and exchange rates as at December 31, 2021 utilized in the Trimble Report and Ryder Scott Report were based on the average of the forecasts prepared by GLJ Ltd., McDaniel & Associates Ltd. and Sproule Associates Limited effective as at January 1, 2022, which are as follows:

FORECAST PRICES USED IN ESTIMATES AS OF DECEMBER 31, 2021

	Oil					Natural Gas		Canadian Natural Gas Liquids		
Year	WTI Cushing Oklahoma $US/ bbl	Canadian Light Sweet 40° API $Cdn/ bbl	Hardisty Heavy 12° API $Cdn/ bbl	Hardisty Bow River 24.9° API $Cdn/ bbl	Western Canadian Select 20.5° API $Cdn/ bbl	AECO 30 Day Spot $Cdn/ MMBtu	Henry Hub $US/ MMbtu	Propane $Cdn/ bbl	Butane $Cdn/ bbl	Pentane $Cdn/ bbl
2022	72.83	86.82	69.49	75.22	74.42	3.56	3.85	43.38	57.49	91.85
2023	68.78	80.73	65.59	69.92	69.17	3.21	3.44	35.92	50.17	85.53
2024	66.76	78.01	62.95	67.26	66.54	3.05	3.17	34.62	48.53	82.98
2025	68.09	79.57	64.22	68.60	67.87	3.11	3.24	35.31	49.50	84.63
2026	69.45	81.16	65.52	69.98	69.23	3.17	3.30	36.02	50.49	86.33
2027	70.84	82.78	66.84	71.37	70.61	3.23	3.37	36.74	51.50	88.05
2028	72.26	84.44	68.18	72.80	72.02	3.30	3.44	37.47	52.53	89.82
2029	73.70	86.13	69.56	74.25	73.46	3.36	3.50	38.22	53.58	91.61
2030	75.18	87.85	70.49	75.49	74.69	3.43	3.58	38.99	54.65	93.44
2031	76.68	89.61	71.91	77.00	76.19	3.50	3.65	39.77	55.74	95.32
Thereafter, per year:										
	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

	U.S. Natural Gas Liquids (Mont Belvieu)			Inflation Rate	Exchange Rate
	Propane	Butane[1]	Condensate		
Year	$US/ bbl	$US/ bbl	$US/ bbl	%/ Year	$US/$ Cdn
2022	41.03	47.83	65.55	0.00	0.80
2023	38.74	44.91	61.90	2.00	0.80
2024	37.60	43.59	60.08	2.00	0.80
2025	38.35	44.46	61.28	2.00	0.80
2026	39.12	45.35	62.51	2.00	0.80
2027	39.90	46.26	63.76	2.00	0.80
2028	40.69	47.19	65.03	2.00	0.80
2029	41.51	48.13	66.33	2.00	0.80
2030	42.34	49.09	67.66	2.00	0.80
2031	43.19	50.07	69.01	2.00	0.80
Thereafter, per year:					
	+2.0%	+2.0%	+2.0%	2.00	0.80

(1) Butane pricess represent a blended price of two-thirds normal butane and one-third iso-butane.

The following table provides the historical weighted average prices realized by Freehold for the year ended December 31, 2021:

FREEHOLD WEIGHTED AVERAGE PRICES
YEAR ENDED DECEMBER 31, 2021

	Light, Medium & Heavy Crude Oil ($/bbl)	Tight Oil ($bbl)	Natural Gas ($/Mcf)	Shale Gas ($/Mcf)	Natural Gas Liquids ($/bbl)	Oil Equivalent ($/boe)
Canada						
Freehold weighted average price	71.61[1]		3.09[2]		45.61	45.14
United States						
Freehold weighted average price		87.44		4.26	36.83	59.35

(1) Includes an immaterial amount of production from tight oil reserves.
(2) Includes an immaterial amount of production from coal bed methane and shale gas reserves.

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

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

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

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

(d) provide improved recovery systems.

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

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

The majority of Freehold's reserves as estimated in the Trimble Report and the Ryder Scott Report are associated with Freehold's royalty interests. Freehold is not responsible for development costs associated with the reserves from its royalty interests. Freehold does not anticipate making any development cost expenditures relating to the reserves associated with its working interest properties and as such no future development costs have been deducted for the purposes of estimating the future net revenue associated with Freehold's reserves in the Trimble Report and Ryder Scott Report.

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

The extent and character of all factual data supplied to Trimble and Ryder Scott were accepted by Trimble and Ryder Scott as represented. No field inspection was conducted.

The after-tax net present value calculation of our reserves reflects the tax burden on our properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying management's discussion and analysis for additional tax information.

Certain other terms used herein 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.

Reconciliation of Changes in Reserves

The following table is a reconciliation of gross reserves and is provided as a requirement of NI 51-101. **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 the majority of our assets are royalty interests, they are excluded from this table. This hinders an investor's ability to compare our reserves to exploration and development companies. Therefore in addition to presenting the reconciliation using gross reserves, we have also presented the reconciliation using net reserves.

As all of Freehold's interests in the United States are royalty interests, the reserves associated with such interests would not be reflected in gross reserves. As such, Freehold has only presented a gross reserves reconciliation for Canada which also represents the gross reserves reconciliation for Freehold's total assets.

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS[(1)]

CANADA	**Light and Medium Oil**			**Tight Oil**			**Heavy Oil**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2020	-	-	-	-	-	-	4	2	6
Production	-	-	-	-	-	-	-	-	-
Technical revisions	-	-	-	-	-	-	-	-	-
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	(4)	(2)	(6)
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2021	-	-	-	-	-	-	-	-	-

CANADA	Conventional Natural Gas			Coal Bed Methane			Shale Gas		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2020	244	121	364	-	-	-	-	-	-
Production	(164)	-	(164)	(2)	-	(2)	-	-	-
Technical revisions	465	48	512	2	-	2	-	-	-
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	165	88	254	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2021	**710**	**257**	**966**	**-**	**-**	**-**	**-**	**-**	**-**

CANADA	Natural Gas Liquids			Total Oil Equivalent		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2020	14	6	20	59	29	87
Production	(3)	-	(3)	(31)	-	(31)
Technical revisions	2	(4)	(2)	79	4	84
Extensions and improved recovery	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	(4)	(2)	(6)
Economic factors	-	-		27	15	43
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2021	**12**	**3**	**16**	**131**	**46**	**177**

(1) Columns may not add due to rounding.

The following reserves reconciliation tables are provided as an aid to the investor. The tables are based on net reserves and are consistent with our disclosure in previous years.

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS[1]

CANADA	Light and Medium Oil			Tight Oil			Heavy Oil		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2020	5,052	4,567	9,619	787	247	1,034	2,358	822	3,180
Production	(923)	-	(923)	(136)	-	(136)	(493)	-	(493)
Technical revisions	542	(416)	127	(50)	(32)	(82)	409	(128)	281
Extensions and improved recovery	69	173	242	174	124	299	265	232	497
Acquisitions[2]	-	-	-	-	-	-	25	31	55
Dispositions	-	-	-	-	-	-	(3)	(2)	(5)
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2021	**4,740**	**4,325**	**9,064**	**776**	**339**	**1,115**	**2,560**	**956**	**3,516**

CANADA	Conventional Natural Gas			Coal Bed Methane			Shale Gas		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2020	51,898	18,023	69,921	1,402	321	1,722	2,196	996	3,192
Production	(8,809)	-	(8,809)	(187)	-	(187)	(323)	-	(323)
Technical revisions	1,601	(341)	1,260	192	(54)	138	271	(14)	258
Extensions and improved recovery	1,490	1,473	2,962	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	149	80	230	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2021	**46,328**	**19,236**	**65,564**	**1,407**	**266**	**1,673**	**2,145**	**982**	**3,127**

CANADA	Natural Gas Liquids			Total Oil Equivalent		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2020	1,732	678	2,410	19,178	9,537	28,714
Production	(342)	-	(342)	(3,446)	-	(3,446)
Technical revisions	143	(50)	94	1,389	(693)	696
Extensions and improved recovery	123	84	207	878	860	1,738
Acquisitions[2]	-	-		25	31	55
Dispositions	-	-	-	(3)	(2)	(5)
Economic factors	-	1	1	25	14	39
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2021	**1,656**	**713**	**2,370**	**18,045**	**9,747**	**27,792**

UNITED STATES	**Tight Oil**			**Shale Gas**			**Natural Gas Liquids**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2020	314	178	491	646	369	1,016	10	5	15
Production	(413)	-	(413)	(1,523)	-	(1,523)	(133)	-	(133)
Technical revisions	(82)	(108)	(190)	(85)	(272)	(357)	3	(3)	-
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions[(2)]	4,466	8,418	12,884	13,469	21,350	34,819	1,454	2,253	3,707
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	1	1
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2021	4,285	8,487	12,772	12,506	21,447	33,954	1,334	2,255	3,589

UNITED STATES	**Total Oil Equivalent**		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2020	432	244	676
Production	(800)	-	(800)
Technical revisions	(93)	(156)	(250)
Extensions and improved recovery	-	-	-
Acquisitions[(2)]	8,165	14,229	22,394
Dispositions	-	-	-
Economic factors	-	1	1
Infill drilling	-	-	-
Discoveries	-	-	-
December 31, 2021	7,703	14,317	22,020

TOTAL	**Light and Medium Oil**			**Tight Oil**			**Heavy Oil**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2020	5,052	4,566	9,619	1,100	425	1,525	2,358	822	3,180
Production	(923)	-	(923)	(549)	-	(549)	(493)	-	(493)
Technical revisions	543	(416)	126	(132)	(140)	(272)	409	(128)	281
Extensions and improved recovery	69	173	242	174	124	299	265	232	497
Acquisitions[(2)]	-	-	-	4,466	8,418	12,884	24	31	55
Dispositions	-	-	-	-	-	-	(3)	(2)	(5)
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2021	**4,740**	**4,325**	**9,064**	5,061	8,826	13,887	**2,560**	**955**	**3,516**

TOTAL	**Conventional Natural Gas**			**Coal Bed Methane**			**Shale Gas**		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2020	51,898	18,023	69,921	1,402	321	1,722	2,843	1,365	4,208
Production	(8,809)	-	(8,809)	(187)	-	(187)	(1,846)	-	(1,846)
Technical revisions	1,601	(341)	1,260	192	(54)	137	186	(286)	(99)
Extensions and improved recovery	1,490	1,473	2,962	-	-	-	-	-	-
Acquisitions[2]	-	-	-	-	-	-	13,469	21,350	34,819
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	149	80	230	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2021	**46,328**	**19,236**	**65,564**	**1,407**	**266**	**1,673**	14,651	22,429	37,081

TOTAL	**Natural Gas Liquids**			**Total Oil Equivalent**		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2020	1,742	683	2,425	19,609	9,781	29,390
Production	(475)	-	(475)	(4,246)	-	(4,246)
Technical revisions	146	(53)	94	1,296	(849)	446
Extensions and improved recovery	123	84	207	878	860	1,738
Acquisitions[2]	1,454	2,253	3,707	8,189	14,260	22,449
Dispositions	-	-	-	(3)	(2)	(5)
Economic factors	-	1	1	25	14	39
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2021	2,990	2,968	5,959	25,748	24,063	49,812

(1) Columns may not add due to rounding.
(2) In 2021, Freehold completed a number of acquisitions in the United States and some smaller acquisitions in Canada. For more information about these acquisitions see "*General Development of the Business*".

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards in the COGE Handbook. At December 31, 2021, the aggregate proved net undeveloped reserves assigned in the Trimble Report and Ryder Scott Report represented 11% of the aggregate proved net reserves assigned in such reports. At December 31, 2021, the aggregate probable net undeveloped reserves assigned in the Trimble Report and Ryder Scott Report represented 34% of the aggregate probable net reserves assigned in such reports. The following provides an explanation of how both Trimble and Ryder Scott attributed proved undeveloped reserves and probable undeveloped reserves in their respective reports and the expectations as to the development of such undeveloped reserves.

In respect of Freehold’s Canadian assets, proved net undeveloped reserves represented 13% of the total proved net reserves assigned in the Trimble Report. The proved undeveloped reserves in the Trimble Report relate to locations that are within actively developed resource plays and adjacent to existing production. In the Trimble Report, 57% of the proved undeveloped reserves are forecast to be drilled in the next two years with the remainder forecast to be drilled in the next five years. All expected drilling beyond the two year time frame is associated with resource plays and such proved undeveloped reserves have been validated based on geology and proximity to production; however, the development of such reserves has been scheduled beyond the first two years to correlate with the historical development drilling timeframes in individual areas. For example, in the Dodsland Viking resource play which represents approximately 35% of proved undeveloped reserves in the Trimble Report, future development is forecasted at an average of 78 locations per year over five years to match recent historical drilling results.

In respect of Freehold’s United States assets, proved net undeveloped reserves assigned represented 7% of the total proved net reserves assigned in the Ryder Scott Report. The proved undeveloped reserves in the Ryder Scott Report relate to drilled uncompleted wells or wells for which permits for drilling have been received. All of the proved undeveloped reserves in the Ryder Scott Report are expected to be developed in 2022.

Probable net undeveloped reserves assigned in the Trimble Report represented 26% of the total proved plus probable net reserves assigned to Freehold's Canadian assets. Similar to the proved undeveloped reserves in the Trimble Report, the probable undeveloped reserves in the Trimble Report relate to locations that are within actively developed resource plays and in close proximity to existing production (although in most cases farther away from existing production than the locations associated with proved undeveloped reserves). The majority of these reserves are in unconventional resource plays where reserves are estimated from analog type curve analysis. In the Trimble Report, 18% of the probable undeveloped reserves are forecast to be drilled in the next two years. The balance of the probable undeveloped reserves in the Trimble Report are forecast to be drilled within ten years and have been validated based on geology and proximity to production but are deferred to correlate with the historical development drilling timeframes in individual areas. For example, in the Dodsland Viking resource play which represents approximately 51% of probable undeveloped reserves booked in the Trimble Report, future development is forecasted at an average of 78 locations per year for 5 years to match recent historical drilling results, then an average of 67 locations per year from 2027 to 2031.

Probable net undeveloped reserves assigned in the Ryder Scott Report represented 57% of the total proved plus probable net reserves assigned to Freehold's United States assets. Similarly to the probable undeveloped reserves booked in the Trimble Report, the probable undeveloped reserves in the Ryder Scott Report relate to locations that are within actively developed resource plays and in close proximity to existing production. The majority of these reserves are in unconventional resource plays where reserves are estimated from analog type curve analysis. In the Ryder Scott Report, all of the probable undeveloped reserves are forecast to be drilled between 2023 and 2031, with 16% forecast to be drilled in 2023 . The balance of the probable undeveloped reserves in the Ryder Scott Report, which are forecast to be drilled between 2024 and 2031, have been validated based on geology and proximity to production but are deferred to correlate with the historical development drilling timeframes in individual areas.

In most cases the development of undeveloped reserves is not within the control of Freehold as it only holds a royalty interest in such reserves and therefore does not have control or influence on the development of such reserves. The development of undeveloped reserves will be dependent on a number of factors including commodity pricing and the availability of capital for our royalty payors to develop such reserves.

The following tables set forth the proved undeveloped reserves and the probable undeveloped net reserves by product type, attributed to Freehold's assets for the years ended December 31, 2021, 2020, and 2019, based on forecast prices and costs:

INITIAL PROVED UNDEVELOPED NET RESERVES
FIRST ATTRIBUTED BY YEAR
FORECAST PRICES AND COSTS

Year	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbls)
2019	794	-	109	323	-	15
2020	160	-	94	89	-	6
2021	-	441	156	145	1,042	140
Total Booked for Current Year	1,085	539	413	1,724	2,006	199

INITIAL PROBABLE UNDEVELOPED NET RESERVES
FIRST ATTRIBUTED BY YEAR
FORECAST PRICES AND COSTS

Year	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbls)
2019	2,181	-	61	1,176	-	49
2020	580	-	53	297	-	18
2021	-	7,246	208	113	18,106	1,877
Total Booked for Current Year	3,310	7,331	352	4,000	18,604	2,062

Significant Factors or Uncertainties

The reserve and recovery information contained in the Trimble Report and Ryder Scott Report are only estimates and the actual production and ultimate reserves may be greater or less than the estimates prepared by Trimble and Ryder Scott.

The value of the Common Shares will depend upon, among other things, the reserves attributable to our properties. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for our properties will vary from estimates and those variations could be material. The reserve and cash flow information contained in this Statement represents estimates only. Reserves and estimated future net cash flow from our properties have been evaluated by Trimble and Ryder Scott, independent qualified reserves evaluators. Trimble and Ryder Scott consider a number of factors and makes assumptions when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices;
- assumptions about future production levels, development costs and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- future drilling on our Royalty Lands by third parties;
- timing and amount of capital expenditures;
- marketability of production;
- future prices of oil and natural gas;
- operating costs and royalties; and
- other government levies that may be imposed over the producing life of reserves.

These factors and assumptions were based on prices at the date the evaluation was prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of these factors are subject to change and are beyond our control. For example, the evaluation is based in part on the assumed success of drilling and resources recovery activities intended to be undertaken in future years. Actual reserves and estimated cash flows will be less than those contained in the evaluation to the extent that such activities do not achieve the level of success assumed in the evaluation. Furthermore, cash flows may differ from those contained in the evaluation depending upon whether capital expenditures and operating costs differ from those estimated in the evaluation.

Description of Properties

Freehold had oil and natural gas interests in producing and non-producing lands located in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba and Ontario in Canada and the states of Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas and Wyoming in the United States encompassing approximately 6.3 million gross acres at December 31, 2021.

Producing lands include Crown, freehold, unitized and non-unitized oil and natural gas and potash production. The properties are operated by experienced operators. Our top ten active drillers through year-end 2021 were in alphabetic order: Bonterra Energy Corp., Crescent Point Energy Corp., Crownquest Operating LLC, Marathon Oil Company, Pioneer Natural Resources USA, Inc., Surge Energy Inc., Tamarack Acquisition Corp. (which is a subsidiary of Tamarack Valley Energy Ltd.), Teine Energy Ltd., Tourmaline Oil Corp. and Whitecap Resources Inc.

Our Royalty Lands consist of a large number of properties with generally small volumes per property. Many of our leases and royalty agreements allow us to take our share of oil and natural gas in-kind, which allows Freehold to take ownership of a percentage of the oil and natural gas produced rather than receiving a financial royalty payment. As part of our risk mitigation program, we carefully monitor our royalty receivables and may choose to take our royalty in-kind if there are benefits in doing so. As of December 31, 2021, we take in-kind and market approximately 3% of our total royalty production using 30-day contracts.

Approximately 99% of our gross land holdings are royalty interests, from which we derive the majority of our income.

In the following discussion, all references to reserves are net, utilizing forecast prices and costs, before tax. All references to royalty production are net, and all references to working interest production are gross. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Royalty Interests

The unique characteristics of royalties provide royalty holders with special commercial benefits not available to the working interest owner because the royalty holder enjoys the upside potential of the property with reduced risk. A royalty interest differs significantly from a working interest in that a holder of a royalty interest is generally not responsible for, and has no obligation to contribute additional funds for any purpose, including operating or capital costs, or environmental or reclamation liabilities; whereas a holder of a working interest is liable for its share of capital, operating and environmental costs, usually in proportion to its ownership percentage, and it receives its pro rata share of revenue.

Our royalty reserves are derived from: (i) leased mineral title lands that we own and upon which we are paid lessor royalties from the lessee; (ii) royalty assumption lands which are mineral title properties owned by third parties in respect of which we are reserved royalties and which, by their terms, are expressed to be interests in land; and (iii) GORR lands leased by third parties upon which such third parties pay Freehold contractual royalties or net profits interests, which may or may not be interests in land. Mineral title and royalty assumption lands do not expire, while GORRs generally expire at the end of the lease's productive life. Mineral title lands and royalty assumption lands derived from mineral titles are held in perpetuity.

Mineral Title Lands

On mineral title lands, royalty revenue is derived from the royalties payable to Freehold (lessor) in the form of lessor royalties through the lease documents issued to the companies (lessees) that have producing wells located thereon. In 2021, this category of land provided approximately 45% of our royalty revenue.

In Canada, we have ownership interests in mineral titles ranging from 10% to 100% and recover the applicable royalty, ranging from 10% to 22.5%, of all oil and natural gas products produced or sold from the leased lands. For example, if our interest in a mineral title property is 50% and the royalty rate applicable to the lease is 20% then we would be entitled to receive the proceeds from the sale of 10% (50% multiplied by 20%) of the oil or natural gas produced for the period. In 2021, this category of land accounted for approximately 17% of our total royalty acreage in Canada.

Our mineral title lands encompass approximately 1,018,000 acres, of which 44% are leased and 56% are unleased. The mineral title lands also include approximately 665,500 undeveloped acres, representing potential for future development.

In the United States we have ownership interests in mineral titles and recover the applicable royalty, ranging from 12.5% to 25%, of all oil and gas produced from the leased lands. In 2021, this category of land accounted for approximately 81% of our total royalty acreage in the United States.

We also hold mineral title interests in potash, as described below under the heading "*Description of Royalty Lands – Potash*".

Royalty Assumption Lands

In Canada, we hold royalty interests in approximately 90,000 gross acres of royalty assumption lands, of which approximately 18,500 acres are undeveloped. These mineral title properties, referred to as royalty assumption lands, are owned by a number of third party oil and gas companies in respect of which royalties (varying from 4.7% to 6.5%) have been reserved to Freehold. As the royalty interests with respect to the royalty assumption lands are a title royalty representing, by their terms, an interest in land, these royalties are held in perpetuity. In 2021, this category of land accounted for approximately 1% of our total royalty acreage and provided approximately 1% of our royalty revenue.

We do not own any royalty assumption lands in the United States.

Gross Overriding Royalty Lands

GORRs are contractual in nature and therefore are not held in perpetuity but rather expire upon the termination of the lease(s) or agreement(s) which generally occurs when production has ceased from the subject lands. These lands consist of properties leased by a number of third party oil and gas companies in respect of which contractual royalties or net profits interests have been reserved to Freehold. In 2021, this category of land provided approximately 48% of our royalty revenue.

In Canada, we hold GORRs in approximately 5.1 million acres, of which approximately 1.5 million acres are undeveloped. In 2021, this category of land accounted for approximately 82% of our total royalty acreage in Canada.

In the USA, we hold GORRs across approximately 150,000 drilling unit acres, of which the majority are developed. These lands consist of properties leased by a number of third party oil and gas companies in respect of which contractual royalties have been reserved to Freehold. In 2021, this category of land accounted for approximately 19% of our total royalty acreage in the United States.

The granting of a GORR usually arises as a result of: (i) providing capital in exchange for granting the royalty; or (ii) converting a participating interest in a joint venture relationship into a royalty. GORRs are based on the proceeds from the sale of gross production and are generally free of any operating, capital and environmental costs.

Production Volume Royalty

Production volume royalties are arrangements under which the producer of oil and gas production sells a percentage of its volumes in exchange for a cash payment and, in certain cases, a contribution to work commitments conducted within a specific timeframe.

In 2021, this category of royalty interests provided approximately 5% of our royalty revenue.

We do not have production volume royalties in the United States.

Description of Royalty Lands

Our royalty interests represent a geologically and geographically diverse portfolio of properties.

The following table summarizes, by area, our average royalty interest, net reserves and reserves value as at December 31, 2021, wells drilled, oil and natural gas production, and royalty interest for 2021 for our Royalty Lands:

Year ended December 31, 2021		Alberta West	Saskatchewan East	Eagle Ford (U.S.)	Permian (U.S.)	North Dakota & Other (U.S.)	Total
Average royalty interest [(1)]	(%)	2.3	2.2	1.4	0.3	0.5	1.0
Wells drilled	(gross)	240	200	66	123	26	655
Royalty interest revenue[(2)]	($000s)	83,719	73,636	25,997	9,341	13,627	206,320
Average net daily production	(boe/d)	6,627	2,965	1,019	384	763	11,758
Oil and NGL	(bbls/d)	2,571	2,695	794	299	375	6,734
Natural gas	(Mcf/d)	24,335	1,620	1,350	510	2,328	30,143
Net proved reserves	(Mboe)	11,962	5,964	5,095	1,439	1,169	25,629
Oil and NGL	(Mbbls)	4,320	5,403	4,013	1,107	499	15,342
Natural gas	(MMcf)	45,851	3,368	6,490	1,995	4,021	61,725
Net proved plus probable reserves	(Mboe)	17,058	10,572	13,532	6,252	2,236	49,650
Oil and NGL	(Mbbls	6,392	9,661	10,834	4,867	661	32,415
Natural gas	(MMcf)	63,996	5,470	16,190	8,313	9,451	103,420
Future Net Revenue[(1)(2)]							
Discounted at 10% per year	($000s)	338,242	411,595	426,269	172,957	37,452	1,386,515
	(% of total)	24.4	29.7	30.7	12.5	2.7	100

(1) Based on proved plus probable reserves and forecast prices as assigned in the Trimble Report and the Ryder Scott Report.
(2) Excludes revenue from potash, interest and other.

The following table summarizes, by region, the gross royalty acreage with respect to our Royalty Lands, as at December 31, 2021:

Area	Developed Gross Acres	Undeveloped Gross Acres[(1)]	Total Gross Acres
Alberta West	3,238,196	1,510,035	4,748,231
Saskatchewan East	719,426	681,279	1,400,705
Eagle Ford (US)	100,103	366	100,469
Permian (US)	9,235	1,240	10,475
North Dakota & Other (US)	7,136	47	7,183
Potash	11,669	7,512	19,181
Total	4,085,765	2,200,479	6,286,244

(1) Undeveloped Royalty Lands are lands without producing or potentially producing wells.

Alberta West

In 2021, 55% of our gross royalty drilling in Canada occurred in the Alberta West area, which includes all of the Royalty Lands in B.C. and Alberta. These wells primarily targeted established liquids-rich gas and oil plays of the Cardium, Viking, and Mannville, as well as continued development drilling in the Clearwater play. In this area, 100% of the wells are horizontal drills and over 95% of the wells targeted oil. Cardium drilling resulted in 54 gross wells, or 24% of gross wells drilled in the area. Mannville drilling resulted in 53 gross wells, or 24% of gross wells drilled in Alberta West. The Clearwater play saw 57 gross wells drilled in 2021, or 25% of Alberta West drilling.

Saskatchewan East

In 2021, 45% of Freehold's gross royalty drilling in Canada occurred in the Saskatchewan East area, which includes all of the Royalty Lands in Saskatchewan and Manitoba (with some minor acreage in Ontario). In this area, 100% of the wells are horizontal drills targeting oil plays.

In 2021, 54% of the gross royalty wells drilled in the Saskatchewan East region were in the Viking oil resource play. Strong development of the Viking continues to represent core production and growth areas for Freehold.

Other significant plays of value in Saskatchewan East are the Mississippian Carbonates and Bakken plays in southeast Saskatchewan and southwest Manitoba, and the Shaunavon and Cantaur plays in southwest Saskatchewan. Together, these plays accounted for 39% of the gross royalty drilling in Saskatchewan East in 2021. Freehold continues to see the benefit of well-capitalized and active operators pursuing high netback opportunities in this area.

Eagle Ford (U.S. – Texas)

In 2021, Freehold acquired mineral title and GORR interests across approximately 203,000 gross drilling unit acres, and a royalty interest in approximately 2,300 producing wells in the Eagle Ford oil basin in Texas. Freehold's Eagle Ford assets have significant multi-year drilling inventory with almost 1,400 gross future drilling locations (which includes 43 drilling locations booked with attributed proved reserves and 817 drilling locations booked with attributed probable reserves in the Ryder Scott Report) identified for development with over 80% supported by well-capitalized investment grade producers.

Permian (U.S. – Texas and New Mexico)

In 2021, Freehold acquired mineral title and GORR interests across approximately 328,000 gross drilling unit acres and a royalty interest in approximately 1,700 producing wells in the Midland and Delaware plays of the Permian basin in Texas and New Mexico. Freehold's Permian assets also have significant multi-year drilling inventory with over 4,000 gross future development locations (which includes 119 drilling locations booked with attributed proved reserves and 1,866 drilling locations booked with attributed probable reserves in the Ryder Scott Report) identified for development from a diverse group of public and private producers.

North Dakota and Other (U.S.)

In 2021, Freehold acquired mineral title and GORR interests across approximately 255,000 gross drilling unit acres, increasing its total acreage to approximately 274,000 gross drilling unit acres, and a royalty interest in approximately 2,800 producing wells in North Dakota and five other states (Colorado, Louisiana, Oklahoma, Pennsylvania and Wyoming). The primary plays of value are Bakken and Three Forks in North Dakota, Haynesville in Louisiana and Texas and Marcellus in Pennsylvania, with development occurring exclusively through horizontal drilling with well capitalized operators.

Potash

Our potash acreage inventory is approximately 19,100 gross acres in 2021. This consists of leases we have issued on our mineral title to the various operators of eight potash mines. Our leases are included in larger potash units which cover the total mine areas.

The potash mines from which we receive royalties are operated by the Mosaic Company and Nutrien Ltd. In 2021, we received approximately $1.5 million in royalty revenue from the production of approximately eleven tonnes per day of potash. Our interests in potash reserves are an important non-fossil fuel revenue source, however they are not deemed material and as such an independent evaluation of our potash reserves has not been obtained.

Undeveloped Royalty Lands

The undeveloped Royalty Lands are lands without producing, or potentially producing, wells totalling approximately 2.2 million gross acres. Potential exists on these lands for drilling non-unitized zones within producing units, drilling or completing additional zones, infill drilling by reducing well spacing, optimizing drilling locations within spacing units and horizontal drilling. If undeveloped lands are leased and a well is drilled on land adjacent to the Royalty Lands where we own the mineral title and that well is producing from a formation in which we have an interest but that is not producing on the Royalty Lands, generally we have the right to require the lessee of the mineral title to either: (a) drill a well on an undrilled spacing unit on the Royalty Lands; (b) pay a compensatory royalty; or (c) surrender the respective formation.

Drilling Activity

Freehold receives Royalty Income from successful wells drilled on our lands. Drilling activity on the Royalty Lands is anticipated to continue to provide new sources of oil and natural gas Royalty Income in future years, with new wells, and production partially offsetting declines. Freehold is not responsible for any drilling or development activity or expenditures with respect to the Royalty Lands.

The following table summarizes the drilling activity conducted by lessees on the Royalty Lands for the two most recently completed fiscal years.

Years Ended December 31[1]	2021	2020
Royalty Interest Properties (gross wells)		
Oil wells	608	316
Natural gas wells	35	7
Service/other wells	12	49
Dry and abandoned wells	-	-
Total	655	372
Success rate	100%	100%

(1) Includes all drilling on properties acquired during the year from the effective date.

In addition to our royalty interests, we own an immaterial amount of working interest properties in Canada. Our working interest assets in Canada represents less than 1% of our total production in 2021.

Other Oil and Gas Information

Oil and Natural Gas Wells

The following tables set forth, by province and state, the number and status of wells in which we have an interest as at December 31, 2021:

Royalty Lands	Natural Gas Wells	Oil Wells
Canada		
Alberta	15,744	11,833
Saskatchewan	999	11,949
British Columbia	159	28
Manitoba	-	696
Ontario	232	-
Canada Total	17,134	24,506
United States		
Colorado	102	117
Louisiana	42	-
New Mexico	1	11
North Dakota	-	355
Oklahoma	15	70
Pennsylvania	22	9
Texas	375	3,742
Wyoming	1	35
United States Total	558	4,339
Total	17,692	28,845

	Natural Gas Wells			
	Producing		Non-Producing(3)	
Working Interest Properties	Gross	Net	Gross	Net
Alberta	20	10.6	-	-
Saskatchewan	-	-	-	-
British Columbia	-	-	-	-
Manitoba	-	-	-	-
Ontario	-	-	-	-
Total(1)(2)	20	10.6	-	-

(1) Columns may not add due to rounding.

(2) Freehold does not hold any working interests in any oil wells or any wells outside of Canada.

(3) Non-producing wells listed in the table above include all working interest wells that are not currently producing but which are considered capable of producing further volumes of oil or natural gas. In addition to the wells listed in the table, Freehold has a working interest in 211 gross (58.3 net) oil wells, 73 gross (47.8 net) natural gas wells and 8 gross (3.9 net) other wells in Canada that are inactive and are not considered capable of producing any further volumes of oil or natural gas. Some of these wells have been abandoned but not reclaimed and other wells are awaiting to be abandoned.

Properties with No Attributable Reserves

The following table sets forth, by province and state, our undeveloped land holdings as at December 31, 2021:

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Canada			
Alberta	1,477,832	5,938	4,217
Saskatchewan	578,548	596	1,556
British Columbia	32,202	1,359	83
Manitoba	28,343	-	-
Ontario	81,899	-	-
Canada Total	2,198,825	7,894	5,856
United States			
Colorado	-	-	-
Louisiana	-	-	-
New Mexico	-	-	-
North Dakota	-	-	-
Oklahoma	25	-	-
Pennsylvania	9	-	-
Texas	1,619	-	-
Wyoming	-	-	-
United States Total	1,653	-	-
Total	**2,200,478**	**7,894**	**5,856**

There are no material work commitments on our undeveloped land holdings.

The area of unproved properties on which we expect our rights may expire within the next year, are approximately 100,000 gross acres.

Undeveloped lands are calculated by adding the surface area acreage covered by the leases or agreements or portions of the leases or agreements without producing or potentially producing wells. In certain limited circumstances where we have rights in different formations under the same surface area pursuant to different leases or agreements, we have included the acreage with respect to all such leases or agreements. There are no significant factors or uncertainties associated with the undeveloped land.

Tax Horizon

The corporate income tax rate applicable to 2021 was approximately 24% (2020 – 25%) and the rate for 2022 and future years is approximately 24%. Taxable income as a corporation is based on total income and expenses (which will vary depending on commodity prices, production volumes, and costs), reduced by claims for both accumulated tax pools and tax pools associated with current year expenditures. Freehold had no current taxes payable in 2021. In the current commodity price environment, we expect current income tax payable in Canada and the USA in 2022. As at December 31, 2021, Freehold's tax pools were

$972 million (additional information is provided in Freehold's management's discussion and analysis for the year ended December 31, 2021 which is available on SEDAR at www.sedar.com).

Freehold's corporate income tax filings for 2015, 2018, and 2019 were reassessed by the CRA in 2020 (the "**Reassessments**"). Pursuant to the Reassessments, deductions of $92.6 million of non-capital losses (NCLs) by Freehold were denied, resulting in reassessed taxes, interest, and penalties totaling $29.3 million in addition to a denial of $129.9 million of carried forward non-capital losses. Freehold has filed its objection of the Reassessments which required deposits totaling $14.7 million that have been provided to the CRA. Freehold has received legal advice that it should be entitled to deduct the non-capital losses and as such, management remains of the opinion that all tax filings to date were filed correctly and that it expects to be successful in its objection of these Reassessments and therefore the payment of these deposits held by the CRA should be refunded, plus interest, and the denied non-capital losses should be reinstated.

Disallowed NCL's are anticipated to be deducted against taxable income upon filing Freehold's Canadian 2021 income tax return. Prior to then, should the CRA's appeal's officer not overturn the Reassessments, these 2021 NCL deductions are anticipated to be disallowed by the CRA resulting in a reassessment against the Corporation's 2021 income tax. On receipt of this anticipated 2021 reassessment, the Corporation will be required to post an additional deposit of $10 million within 90 days bringing the total posted deposits to $25 million.

The outcome of Freehold's objection to the Reassessments, could impact Freehold's timing for when it may have current taxes payable. For additional information, see "*Legal Proceedings and Regulatory Actions*".

Capital Expenditures

Future capital expenditures are anticipated to maintain or improve production. Freehold may finance capital expenditures from additional issuances of Common Shares, borrowings, farmouts or with working capital.

The following table summarizes capital expenditures in Canada to acquire royalty lands:

Canada	($000s)
Property acquisition costs(1)	
Proved properties	5,816
Undeveloped/unproved properties	-
Development costs	-
Total (2)	5,816

(1) As classified at the time of the acquisition.
(2) We did not incur any exploration costs in 2021.

The following table summarizes capital expenditures in the United States to acquire royalty lands:

United States	($000s)
Property acquisition costs[1]	
Proved properties	368,050
Undeveloped/unproved properties	-
Development costs	-
Total [2]	368,050

(1) As classified at the time of the acquisition.
(2) We did not incur any exploration costs in 2021.

Production Estimates

The following tables set out the volume of gross and net production estimated for the year ended December 31, 2022 in the Trimble Report and the Ryder Scott Report, based on the forecast price case reflected in the estimate of future net revenue disclosed in the tables contained under "*Reserves Data*". No field accounts for more than 20% of the production estimate.

CANADA

	Light and Medium Oil		**Tight Oil**		**Heavy Oil**	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)
Proved						
Developed producing	-	1,874	-	310	-	1,091
Developed non-producing	-	-	-	-	-	8
Undeveloped	-	143	-	26	-	104
Total proved	-	2,016	-	336	-	1,203
Probable	-	156	-	10	-	55
Total proved plus probable[1]	-	2,172	-	346	-	1,258

	Conventional Natural Gas		**Coal Bed Methane**		**Shale Gas**	
Reserves Category	Gross (Mcf/d)	Net (Mcf/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (Mcf/d)	Net (Mcf/d)
Proved						
Developed producing	321	20,374	-	447	-	700
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	341	-	-	-	-
Total proved	321	20,715	-	447	-	700
Probable	5	1,230	-	7	-	11
Total proved plus probable[1]	326	21,945	-	453	-	711

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (boe/d)	Net (boe/d)
Proved				
Developed producing	7	750	61	7,612
Developed non-producing	-	-	-	8
Undeveloped	-	19	-	348
Total proved	7	769	61	7,968
Probable	-	45	1	474
Total proved plus probable(1)	7	814	62	8,442

UNITED STATES

	Tight Oil		Shale Gas		Natural Gas Liquids	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (bbls/d)	Net (bbls/d)
Proved						
Developed producing	-	1,648	-	4,538	-	483
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	212	-	603	-	58
Total proved	-	1,860	-	5,141	-	541
Probable	-	174	-	404	-	46
Total proved plus probable(1)	-	2,034	-	5,545	-	587

	Total Oil Equivalent	
Reserves Category	Gross (boe/d)	Net (boe/d)
Proved		
Developed producing	-	2,887
Developed non-producing	-	-
Undeveloped	-	371
Total proved	-	3,258
Probable	-	287
Total proved plus probable(1)	-	3,545

TOTAL

	Light and Medium Oil		Tight Oil		Heavy Oil	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)
Proved						
Developed producing	-	1,874	-	1,958	-	1,091
Developed non-producing	-	-	-	-	-	8
Undeveloped	-	143	-	238	-	104
Total proved	-	2,016	-	2,196	-	1,203
Probable	-	156	-	184	-	55
Total proved plus probable(1)	-	2,172	-	2,380	-	1,258

	Conventional Natural Gas		Coal Bed Methane		Shale Gas	
Reserves Category	Gross (Mcf/d)	Net (Mcf/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (Mcf/d)	Net (Mcf/d)
Proved						
Developed producing	321	20,374	-	447	-	5,238
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	341	-	-	-	603
Total proved	321	20,715	-	447	-	5,841
Probable	5	1,230	-	7	-	415
Total proved plus probable(1)	326	21,945	-	453	-	6,256

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (boe/d)	Net (boe/d)
Proved				
Developed producing	7	1,233	61	10,499
Developed non-producing	-	-	-	8
Undeveloped	-	77	-	719
Total proved	7	1,310	61	11,226
Probable	-	91	1	761
Total proved plus probable(1)	7	1,401	62	11,987

(1) Columns may not add due to rounding.

Production History

The following tables summarize our production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

CANADA

	2021 Quarter Ended				2020 Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production[1]								
Light and Medium Crude Oil[2] (bbls/d)	3,213	3,146	3,329	3,210	3,046	3,303	3,254	3,732
Heavy Crude Oil (bbls/d)	1,254	1,236	1,199	1,045	1,173	791	920	1,300
Conventional Natural Gas[3] (Mcf/d)	28,028	25,737	24,823	27,054	26,295	24,510	25,503	29,086
NGL (bbls/d)	790	846	928	894	822	857	786	896
Combined (boe/d)	9,930	9,517	9,593	9,659	9,424	9,035	9,211	10,776
Average price realized								
Light and Medium Crude Oil[2] ($/bbl)	87.06	78.40	70.78	60.06	49.00	42.83	28.23	45.31
Heavy Crude Oil ($/bbl)	70.38	68.83	65.39	52.56	31.02	49.37	18.61	27.46
Conventional Natural Gas[3] ($/Mcf)	4.14	3.13	2.58	2.55	2.07	1.75	1.44	1.42
NGL ($/bbl)	55.28	47.82	39.41	40.90	26.87	21.25	15.27	27.06
Combined ($/boe)	57.44	47.57	44.22	37.08	27.82	26.74	17.14	25.08
Royalty expense[4]								
Light and Medium Crude Oil[2] ($/bbl)	-	-	-	-	-	-	0.06	0.05
Heavy Crude Oil ($/bbl)	-	-	-	-	0.02	(0.22)	(0.02)	0.19
Conventional Natural Gas[3] ($/Mcf)	-	-	0.01	0.01	-	-	0.03	(0.02)
NGL ($/bbl)	0.53	0.16	0.33	(0.11)	0.11	0.15	0.07	0.16
Combined ($/boe)	0.01	0.04	0.03	0.01	0.01	-	0.10	0.01
Operating expenses ($/boe)[5]								
Light and Medium Crude Oil[2] ($/bbl)	-	-	-	-	0.10	(0.01)	0.42	0.40
Heavy Crude Oil ($/bbl)	-	-	-	-	0.36	0.89	2.42	3.80
Conventional Natural Gas[3] ($/Mcf)	0.07	0.01	0.10	0.06	0.08	0.06	0.07	0.14
NGL ($/bbl)	0.12	0.46	0.03	0.12	0.30	0.56	0.49	0.44
Combined ($/boe)	0.23	0.02	0.29	0.18	0.33	0.30	0.61	1.01
Netback received[6][7]								
Light and Medium Crude Oil[2] ($/bbl)	87.06	78.40	70.78	60.06	48.90	42.84	27.75	44.86
Heavy Crude Oil ($/bbl)	70.38	68.83	65.39	52.56	30.64	48.70	16.21	23.47
Conventional Natural Gas[3] ($/Mcf)	4.07	3.12	2.47	2.48	1.99	1.69	1.34	1.30
NGL ($/bbl)	54.63	47.20	39.05	40.89	26.46	20.54	14.71	26.46
Combined ($/boe)	57.20	47.51	43.90	36.89	27.48	26.44	16.43	24.06

(1) Represents net production from our Royalty Lands in Canada and our minor working interest production in Canada.
(2) Includes an immaterial amount of production from tight oil reserves.
(3) Includes an immaterial amount of production from coal bed methane and shale gas reserves.
(4) Royalty expense includes all Crown charges and royalty payments to third parties.
(5) Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Overhead recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.
(6) Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.
(7) Excludes income from potash, interest and other.

UNITED STATES[1]

	2021 Quarter Ended				2020 Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production[2]								
Tight Oil (bbls/d)	2,188	892	773	601	192	81	59	203
Shale Gas (Mcf/d)	6,672	3,466	3,553	3,078	360	147	74	274
NGL (bbls/d)	774	279	179	171	5	2	3	1
Combined (boe/d)	4,075	1,748	1,544	1,285	257	108	74	250
Average price realized								
Tight Oil ($/bbl)	96.50	86.20	79.48	65.95	47.62	51.37	19.21	58.65
Shale Gas ($/Mcf)	4.98	4.68	3.64	3.17	3.41	2.50	(5.68)	3.97
NGL ($/bbl)	42.04	31.84	37.71	20.15	14.14	11.78	5.31	25.28
Combined ($/boe)	67.97	58.34	52.53	39.01	40.69	42.34	9.86	52.18
Royalty expense[3]								
Tight Oil ($/bbl)	3.38	3.23	2.70	2.27	12.37	2.25	4.01	12.53
Shale Gas ($/Mcf)	0.56	0.54	0.45	0.38	0.05	0.05	0.07	0.07
NGL ($/bbl)	3.38	3.23	2.70	2.27	-	-	5.31	-
Combined ($/boe)	3.38	3.23	2.70	2.27	9.33	1.77	3.27	10.28
Operating expenses ($/boe)[4]								
Tight Oil ($/bbl)	-	-	-	-	-	-	-	-
Shale Gas ($/Mcf)	-	-	-	-	-	-	-	-
NGL ($/bbl)	-	-	-	-	-	-	-	-
Combined ($/boe)	-	-	-	-	-	-	-	-
Netback received[5]								
Tight Oil ($/bbl)	93.12	82.97	76.78	63.68	35.25	49.12	15.20	46.12
Shale Gas ($/Mcf)	4.42	4.14	3.19	2.79	3.36	2.45	(5.75)	3.90
NGL ($/bbl)	38.66	28.61	35.01	17.88	14.14	11.78	5.31	25.28
Combined ($/boe)	64.59	55.11	49.63	36.74	31.36	40.57	9.86	41.90

(1) Denominated in Canadian dollars.
(2) Represents net production from our Royalty Lands in the United States.
(3) Royalty expense includes all royalty payments to federal and state governments and third parties.
(4) Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Overhead recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.
(5) Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.

The following table summarizes our average daily production from our Royalty Lands in important regions or fields for the year ended December 31, 2021:

	Light and Medium Oil[1] (bbls/d)	Heavy Oil (bbls/d)	Conventional Natural Gas[2] (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
Canada Royalty Lands[3]					
Alberta West	912	838	24,303	775	6,576
Saskatchewan East	2,313	346	1,641	81	3,013
Canada Total	3,225	1,184	25,944	856	9,589

(1) Includes an immaterial amount of production from tight oil reserves.
(2) Includes an immaterial amount of production from coal bed methane and shale gas reserves.
(3) Production from the Royalty Lands is presented on a net basis.

	Tight Oil (bbls/d)	Shale Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
United States Royalty Lands[1]				
Eagle Ford	599	1,349	195	1,019
Permian	231	503	60	375
North Dakota and Other	287	2,348	97	775
United States Total	1,117	4,200	352	2,169

(1) Production from the Royalty Lands is presented on a net basis.

Environmental Obligations

As a royalty owner, Freehold does not directly operate any of our royalty assets. Royalty owners are not generally responsible for operating or capital costs, or environmental or reclamation liabilities. The projects on which we receive royalty revenue are owned and operated by independent oil and gas companies of which many are publicly listed (commonly referred to as our "Third Party Operators" or "Lessees"). Our royalty payors are represented by some of the largest and most recognized Third Party Operators in the Canadian and U.S. oil and gas industry. These companies operate within the Canadian and U.S. regulatory frameworks – which are two of the strongest in the world.

Freehold also owns working interests in oil and natural gas properties. We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of our minor working interest properties upon abandonment. In 2021, our working interest assets represented less than 1% of our total production. Environment, health and safety falls under the responsibility of Rife as Manager of Freehold's assets. Rife has a comprehensive program that includes policies and procedures designed to protect the environment and the health and safety of its employees.

Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs

For the purposes of estimating Reserves Data, abandonment, decommissioning and reclamation costs for all wells (both active and inactive wells) have been taken into account whether or not such wells have been attributed reserves. In addition, abandonment, decommissioning and reclamation of pipelines and facilities were also taken into account for the purposes of estimating Reserves Data. The undiscounted amount of capital costs associated with abandonment and reclamation reflected in the estimates of future net revenue associated with our proved reserves and proved plus probable reserves is approximately $5.4 million for both cases.

Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment and reclamation cost history.

Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties can be found in Freehold's consolidated financial statements for the year ended December 31, 2021 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

Borrowings

Freehold has extendible revolving credit facilities with a total commitment of $300 million consisting of a $285 million syndicated facility and a $15 million operating facility. The syndicated facility can be increased to $360 million pursuant to an accordion feature, subject to incremental lender commitments.

The current maturity date of the credit facilities is September 28, 2024. Freehold may annually request an extension of the then current maturity date, subject to approval by the lenders. Following the granting of any extension, the term to maturity of the credit facilities may not exceed three years.

Borrowings under the credit facilities bear interest at the bank's prime lending rate, bankers' acceptance rates or adjusted term SOFR rates, plus applicable margins. The applicable margin is dependent on the ratio of Freehold's debt to EBITDA on royalty interest properties (calculated as earnings on royalty interest properties before non-cash charges including, but not limited to, interest, taxes, depletion and depreciation and amortization).

We are required to comply with various covenants under the credit facilities including two financial covenants: (1) the ratio of our debt to EBITDA on royalty interest properties shall not at any time exceed 3.5 to 1.0; and (2) the ratio of our debt to capitalization (the aggregate of debt and shareholders' equity) shall not at any time exceed 55%. Pursuant to the terms of our credit facilities, we are restricted from paying dividends if we would be in default under the facilities.

The credit facilities are secured with first charge demand debentures over all of Freehold's Canadian assets and a security agreement and fixed charge mortgage over certain of Freehold's U.S. assets.

Industry Conditions

Companies operating in the oil and gas industry in Canada are subject to extensive regulation and control of operations (including with respect to 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 petroleum 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 Western Canadian oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted.

The Corporation's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of the Corporation's and its royalty payors upstream oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions.

Outlined below are some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the provinces of Alberta, Saskatchewan, British Columbia, and Manitoba, where as at December 31, 2021, the Corporation's Canadian assets were primarily located. While these matters do not affect the Corporation'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 matters carefully.

In addition, the Corporation also holds interests in crude oil and natural gas properties, along with related assets, in the United States. The Corporation's assets and operations in the United States are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Corporation's and its royalty payor's upstream crude oil and natural gas business include all manner of activities associated with the exploration for, and production of, crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or state regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The Corporation will continue to assess and evaluate the conditions and regulations that impact the crude oil and natural gas industry in the United States and the impact such conditions and regulations have on the Corporation's ongoing business.

Pricing and Marketing

Crude Oil

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

Natural Gas

In Canada, the price of natural gas sold intra-provincially or to the United States is determined by negotiation between buyers and sellers. In the United States, the price of sales inter-state or internationally is determined by negotiation between buyers and sellers based upon factors normally considered in the industry such as distance from well to pipeline, pressure, and quality. Natural gas exported from Canada is subject to regulation by the CER and the Government of Canada and in the United States is regulated principally by the Federal Energy Regulatory Commission (the "**FERC**") and the United States Department of Energy (the "**DOE**"). The FERC, which has the authority under the *Natural Gas Act* of 1938 (the "**NGA**") to regulate prices, terms, and conditions for the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to FERC regulation, except interstate pipelines, to resell natural gas at market prices. In addition, under the provisions of the *Energy Policy Act* of 2005, the NGA was amended to prohibit market manipulation in connection with the purchase or sale of natural gas and the FERC established regulations to increase natural gas pricing transparency by requiring certain market participants to report their gas sales transactions annually to the FERC. Facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Although FERC has set forth a general test to determine whether facilities are exempt from FERC jurisdiction as "gathering" facilities, FERC's determinations as to the classification of facilities are performed on a case-by-case basis and FERC has the authority to reclassify facilities previously thought to be non-jurisdictional. The FERC regulates interstate natural gas transportation rates and service conditions under the NGA and the *Natural Gas Policy Act* of 1978 (the "**NGPA**"), which affects the marketing of natural gas, as well as revenues we may receive for sales of our natural gas. Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies.

Natural Gas Liquids

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

Exports

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "**CERA**"). Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Corporation does not directly enter into contracts to export its production outside of Canada.

In the United States, the DOE regulates the exportation and importation of natural gas, including liquefied natural gas. U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a free trade agreement with the United States that provides for national treatment of trade in natural gas; however, the DOE's regulation of imports and exports from and to countries without such free trade agreements is more comprehensive. The FERC also regulates the construction and operation of import and export facilities. In 2015, the United States government repealed the 40-year old ban on exports of crude oil produced in the United States. Accordingly, most exports of crude oil produced in the United States may be made without an export license. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

Transportation Constraints and Market Access

One constraint to the export of oil, natural gas and NGLs 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 are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due, in part, to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets over the last several years.

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.

Pipelines in Canada

Under the Canadian Constitution, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, 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 in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines also require approvals from several levels of government in the United States.

Pipelines in the United States

In the United States, transportation of crude oil is subject to rate and access regulation. The FERC regulates interstate crude oil pipeline transportation rates under the Interstate Commerce Act of 1887 (the "**ICA**"). In general, such pipeline rates must be cost-based. The FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service. Such rates and terms and conditions may not be discriminatory or preferential. At the beginning of 1995, regulations adopted by the FERC generally grandfathered all previously approved interstate transportation rates and established an indexing system for such rates permitting annual adjustments based on the rate of inflation, subject to certain limitations. Every five years, the FERC examines the annual change compared to the actual cost changes. In December 2015, under the five-year re-determination, the FERC adjusted the index level used to determine annual changes to oil pipeline rate ceilings and determined that the Producer Price Index for Finished Goods ("**PPI-FG**") plus 1.23% should be the index level for the five-year period beginning July 1, 2016. In December 2020, the FERC adjusted the index level to be the PPI-FG plus 0.78% for the July 1, 2021 to June 30, 2026 time period. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Intrastate crude oil pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state.

Specific Pipeline Updates

The Enbridge Line 3 Replacement from Hardisty, Alberta to Superior, Wisconsin, came into service in October 2021. The Line 3 Replacement, originally expected to be in-service in late 2019, faced significant permitting difficulties in the United States resulting in the two-year delay. The pipeline provides an incremental 370,000 bbls/day of expert capacity from Western Canada into the United States.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019 and it is expected to be in-service in December 2022; however there continues to be uncertainty about whether the December expected in-service date will be met.

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

Marine Tankers

The *Oil Tanker Moratorium Act*, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Natural Gas and LNG

Natural gas prices in Alberta and British Columbia have been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which is generally lower than the prices received in other North American markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation received federal approval to expand its NOVA Gas Transmission Ltd. pipeline system (the "**NGTL System**") and the expanded NGTL System is expected to be fully operational by April 2022.

Specific Pipeline and Proposed LNG Export Terminal Updates

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

In May 2020, TC Energy Corporation 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 has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of December 2021, construction of the CGL Pipeline is approximately 60% complete.

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

International Trade Agreements

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

Land Tenure

Mineral rights in Canada

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (collectively, "**leases**") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

All 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 disposition. 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.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned 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 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 manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations through *An Act to Amend the Indian Oil and Gas Act* and the accompanying regulations. The Corporation does not have operations on Indigenous reserve lands.

Mineral Rights in the United States

Mineral interests in the United States may be owned privately or by the state or federal government. Rights to explore for and produce privately owned 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 oil and natural gas reserves.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands in Canada or lands owned by the state or federal government in the United States, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province and some states have developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

Royalties and Incentives

General

Each province (and in the case of the U.S., each state) has legislation and regulations in place to govern royalties due to government and establish the royalty rates that producers must pay in respect of the production of resources. The royalty regime in a given province or state is in addition to applicable federal and provincial or state taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. In Canada and the United States, royalties payable on production from lands where the government does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain taxes and other charges on production or revenues may be payable.

Producers and working interest owners of oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

Occasionally, the provincial governments in Western Canada and some state governments in the United States create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

In addition, from time-to-time, including during the COVID-19 pandemic, the Canadian federal government creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry as well as other industries in Canada.

Alberta

Crown royalties

In Alberta, 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.

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, following which time they will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta), came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

Royalties on production from wells subject to 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 Alberta Energy Regulator (the "**AER**"), and incorporates information specific to each well such as vertical depth and lateral length.

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

Under the Old Framework, royalty rates for conventional oil production can be as high as 40% and royalty rates for natural gas production can be as high as 36%. Similar to the Modernized Framework, these rates vary based on the nature of the resource and market prices. The natural gas royalty formula also provides for a reduction based on the measured depth of the well, as well as the acid gas content of the produced gas.

Oil sands production in Alberta is also subject to a royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues and, depending on market prices, the applicable rates are capped at 9%. After payout, the royalty payable is the greater of the gross revenue royalty (described above) and a net revenue royalty based on rates that range from 25% - 40%.

In addition to royalties, producers of oil and natural gas from Crown lands in Alberta are also required to pay annual rentals to the Government of Alberta.

Freehold royalties and taxes

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

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

British Columbia

Crown royalties

On October 7, 2021, the Government of British Columbia launched a comprehensive review of its oil and gas royalty system. Based on the outcomes of this review and input received from the public, a policy announcement will be made in February 2022, to be followed by the implementation of the resulting changes to the royalty regime in spring 2022. Results of the public engagement portion of the review released in February 2022 indicated that the majority of British Columbians are in favour of a "revamped royalty system that puts the interest of British Columbians first and eliminates outdated, inefficient fossil fuel subsidies". Until the changes to the regime are implemented, the current system, established under the *1992 Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation*, will continue to apply.

Under the current system, Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales.

The Crown royalty rate for oil can be as high as 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells, including low-productivity wells, to reflect higher per-unit costs of exploration and extraction. The Crown royalty rate for natural gas and NGLs in British Columbia varies depending on the characteristics of the specific substance and can be as high as 27%, depending on factors such as whether the gas is classified as conservation gas or non-conservation gas, the applicable reference price and select price.

Freehold royalties and taxes

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

For 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. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

Saskatchewan

Crown royalties

Crown royalties payable on the production of oil and natural gas in Saskatchewan are paid on a well-by-well basis. Producers of oil and natural gas receive royalty invoices from the Government on a monthly basis.

The Crown royalty payable on oil production is paid on a well-by-well basis and depends on a number of variables, including the type and vintage of oil, the quantity of oil produced in a given month, the average wellhead price and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 5% - 20% and the marginal royalty rate ranges from 25% - 45%. Base royalty rates represent the minimum royalty rate payable on production of petroleum substances, regardless of the level of production. Marginal royalty rates charge increasing royalty rates as the level of production increases. Marginal royalty rates, such as those used in Saskatchewan's royalty regime, are designed to allow producers of petroleum products to more quickly recover initial investments at the beginning of a project's life cycle. The Crown royalty payable on natural gas production 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 and classification of the natural gas, the finished drilling date of the well and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 0% - 20% and the marginal royalty rate ranges from 30% - 45%.

Freehold royalties and taxes

Royalty rates for the production of privately owned 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. Additionally, a mineral rights 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.

Resource Surcharge

In addition to royalties, certain entities operating in Saskatchewan must pay a tax, known as a "**Resource Surcharge**", on the value of resources sales. The Resource Surcharge rate is 3% of the sales value of all oil and natural gas produced from wells drilled in Saskatchewan before October 1, 2002, and 1.7% for any wells drilled thereafter.

Manitoba

Crown royalties

The Crown royalty payable on oil production in Manitoba depends on the classification of the oil, which depends on variables such as the age and characteristics of the well, including whether the well is a vertical or horizontal well. Based on these factors, the royalty rate can be as high as approximately 43% of monthly production from a well or allocated to a spacing unit or unit tract, as applicable. The Crown royalty payable on natural gas production is a flat 12.5% of monthly revenue. Manitoba's crown royalty regime is currently under review, with any resulting changes to the regime anticipated to come into effect in 2023.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale between 0% and approximately 40% and is based on monthly production volume and varies with the classification of the 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.

United States

Royalties payable for oil and gas production vary depending on whether the oil and gas estate is owned by the federal government, the state government or a private landholder. Generally, the current federal royalty rate for onshore oil and gas is 12.5%. Production may also be subject to oil and gas severance taxes at the state level, although such severance taxes may include exemptions available for low-producing wells. Royalties payable under private oil and gas leases in North Dakota are determined by negotiations between the mineral owner and the lessee.

Regulatory Authorities and Environmental Regulation

General

The oil and gas industry in Canada and the United States is currently subject to environmental regulation under a variety of federal, provincial, state, 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 oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such 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 GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry.

Canada

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.

The CERA and the *Impact Assessment Act* (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. 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 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 Impact Assessment Agency (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. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75km of new rights of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial greenhouse gas ("**GHG**") emissions caps and certain refining, processing and storage facilities.

The federal government of Canada 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 Canadian federal government has stated should provide more certainty as to the length of the full review process. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA and the hearing is expected to take place in the first half of 2021.

Alberta

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

The Government of Alberta's land-use policy 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, earthquakes 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 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 oil and natural gas producers working in certain areas where the likelihood of an earthquake 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**") The Corporation does have royalty lands in all three of these regions. 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 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 of earthquakes 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 *Oil and Gas Activities Act* (the "**OGAA**") regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**BC OGC**") has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BC OGC 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 OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. 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 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 an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC OGC before resuming production. The permitting process requires 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 OGC issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). The BC OGC introduced enhancements to the Special Project Order in April 2021, expanding the boundaries of the order. The Corporation owns a very minor land position in this 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 OGC, and notifying the BC OGC 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 OGC 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 earthquake and developing an approved protocol for subsequent earthquakes, to initiating such protocols, to suspending operations until permitted to resume by the BC OGC. Under the enhanced Special Project Order, a magnitude 3.0 or above seismic event will result in the immediate suspension of fracturing activities from the suspected well(s) for a minimum of five calendar days. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

An updated *Environmental Assessment Act* came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises 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" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the British Columbia Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project.

Saskatchewan

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

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 oil and natural gas resources. 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.

United States

Oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Oil and natural gas operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

The following is a summary of the more significant existing environmental, health and safety laws and regulations in the United States to which our business operations or the business operations of our royalty payors in the United States are subject and for which compliance may have a material adverse impact on the development on our royalty lands and our results of operation or financial position.

The *Comprehensive Environmental Response, Compensation, and Liability Act* ("**CERCLA**") and comparable state statutes impose strict, joint and several, and retroactive liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the government or private parties to file claims requiring cleanup actions, demands for reimbursement for cleanup costs, or natural resource damages, or for neighbouring landowners and other third parties to file tort claims for bodily injury and property damage allegedly caused by hazardous substances released into the environment. CERCLA currently excludes petroleum from its definition of "hazardous substance", but related substances such as BTEX (benzene, toluene, ethylbenzene and xylene) chemicals are listed.

The federal *Solid Waste Disposal Act,* as amended by the *Resource Conservation and Recovery Act*, (collectively, "**RCRA**") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance, as well as requirements for corrective actions. Under the RCRA oil and gas exploration and production waste ("**E&P waste**") exemption, E&P waste is regulated as a "solid waste" rather than a "hazardous waste." Despite several environmental groups suing the US Environmental Protection Agency (the "**EPA**") in 2016 for failing to update its rules for management of E&P waste under RCRA, EPA determined that regulatory revisions were not necessary, which satisfied its obligation under the Consent Decree that resolved the suit. Despite this outcome there remains a risk that changes in the current RCRA E&P waste exemption and comparable state laws could result in an increase in the costs to manage and dispose of wastes. Additionally, certain states may regulate E&P wastes more stringently than the federal government. Also, ordinary industrial wastes that are not uniquely associated with oil and gas operations, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, may be regulated as hazardous waste.

Other statutes relating to the storage and handling of pollutants include the *Oil Pollution Act of 1990* (the "**OPA**"), which requires certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The OPA contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. State laws mandate oil cleanup programs with respect to contaminated soil. A failure to comply with the OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

The *Endangered Species Act* (the "**ESA**") seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, or destroy or modify the critical habitat of such species. Under the ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize such species or their habitat. The ESA has been used to prevent or delay drilling activities and provides for criminal penalties for willful violations of its provisions. Recent changes to the ESA, if they survive legal challenge, would change the scope of the rule's application. In August 2019, the Trump administration issued three final rules regarding implementation of the ESA. Under the new rules, the administration changed the considerations for listing, delisting or reclassifying species. The new rules limit the framework for the term "foreseeable future," a standard used to determine whether a species is threatened, to reference a period as long as the conditions posing a danger are probable. The new rules also indicate that, when dedicating critical habitat, occupied spaces are considered first to lessen the regulatory burdens on unoccupied spaces. Unoccupied spaces must be proven essential to conservation and must contain physical or biological features essential to that species' conservation. Additionally, the final rules removed the phrase "without reference to possible economic or other impacts of such determination" of a species' status, which could open determinations for listing species to economic considerations. A second rule revised the rule related to threatened species to remove the default extension of most of the prohibitions for activities involving endangered species to threatened species, making it a case-by-case determination. These new rules apply only towards future listing of species, but they would significantly limit the scope of the ESA and likely result in less regulatory burden on certain unoccupied spaces. However, the Biden administration has introduced regulatory proposals to rescind changes the Trump administration made to the Endangered Species Act regulations. The rules also are being challenged by environmentalists in federal court. Rescinding the Trump revisions to the Endangered Species Act regulations may cause operators in the United States to incur increased operating expenses and potential delays. Other statutes that provide protection to animal and plant species and that may apply to oil and gas operations include, without limitation, the *Fish and Wildlife Coordination Act*, the *Fishery Conservation and Management Act*, the *Migratory Bird Treaty Act*, and the *Bald and Golden Eagle Protection Act*.

The *National Environmental Policy Act* ("**NEPA**") requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal and certain Indian lands would result in a "significant impact" on the environment. For purposes of NEPA, "major federal action" can be something as basic as issuance of a required permit. For oil and gas operations on federal and certain Indigenous lands or requiring federal permits, NEPA review can increase the time for obtaining approval and impose additional regulatory burdens on the natural gas and oil industry, thereby increasing our costs of doing business and our profitability. On July 16, 2020, the White House Council on Environmental Quality ("**CEQ**") published a Final Rule revising NEPA's implementing regulations (the "**2020 Rule**"). The changes to NEPA introduced a "non-major" category which would exempt certain types of governments, allowing them to move forward without an environmental assessment. The changes also eliminate reference to "cumulative" effects and focus more on causation. This would limit the scope of the assessment and narrow the environmental effects associated with the proposed action to those expected as a direct outcome, rather than assessing indirect effects and their cumulative impact. The 2020 Rule would make the NEPA process more efficient and less time consuming by streamlining the entire process and proposing page and time limits. Additionally, the Final Rule introduced additional responsibilities for commenters. For example, comments would be allowed during the scoping period, and if a commenter fails to raise certain issues at the onset of the project those issues may be deemed waived. This may have the effect of less or quicker judicial review, if the issues are waived. The Final Rule would likely result in a quicker turnaround time for obtaining leases and permits. Twenty-three states and several environmental groups filed two separate lawsuits in California federal court challenging the Final Rule, both of which are ongoing. In addition, in October 2021, the CEQ published a notice of proposed rulemaking (the "**2021 Proposed Rule**") to reverse several of the Trump administration's revisions to the NEPA implementing regulations. The 2021 Proposed Rule seeks to revise three aspects of the 2020 Rule back to the prior regulations with minor modifications: (1) the "purpose and need" of a proposed action; (2) the definition of "effects," restoring the prior definitions of direct, indirect, and cumulative effects; and (3) agency flexibility to develop

NEPA implementation procedures that go beyond the CEQ regulatory requirements. CEQ has announced that it intends to propose additional revisions to the 2020 Rule to ensure efficient and effective environmental reviews, provide regulatory certainty, promote better decision-making, and address climate change and environmental justice objectives.

The *Clean Water Act* (the "**CWA**") and comparable state statutes impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States ("**WOTUS**"). The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. The CWA regulates stormwater run-off from oil and natural gas facilities and requires a stormwater discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample stormwater run-off from its operations. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in waters of the United States unless authorized by an appropriately issued permit.

On April 21, 2020, the EPA and U.S. Army Corps of Engineers released a final rule to define WOTUS (the "**2020 WOTUS Rule**") that identified four categories as jurisdictional WOTUS: (1) the territorial seas waters that are currently used, or were used in the past, or may be susceptible to use, in interstate or foreign commerce, including waters that are subject to the ebb and flow of the tide ("**Traditional Navigable Waters**" or "**TNW**") and any TNW that have been, are, or could be used in interstate or foreign commerce; (2) Tributaries of TNW, which are naturally occurring surface water channels that contribute perennial or intermittent flow into a TNW "in a typical year," either directly or indirectly; (3) Ditches, which are artificial channels used to convey water that are either TNWs, constructed in a tributary, or constructed in an adjacent wetland; (4) Lakes and ponds that contribute perennial or intermittent surface flow to a TNW, tributary of a TNW, or a wetland adjacent to a TNW, or are flooded by another jurisdictional WOTUS in a typical year; (5) Impoundments of other jurisdictional WOTUS; and (6) Adjacent Wetlands, which must actually abut a jurisdictional WOTUS or have a direct hydrological surface connection to a jurisdictional WOTUS in a typical year, TNW, tributary, or lake, pond, or impoundment of a TNW.

However, in August 2021, the U.S. District Court for the District of Arizona's vacated and remanded the 2020 WOTUS Rule. In response, the federal agencies have halted implementation of the 2020 WOTUS Rule nationwide and are interpreting "waters of the United States" consistent with the pre-2015 regulatory regime until further notice.

In January 2022, the United States Supreme Court agreed to hear the Sackett v. EPA case from the United States District Court for Ninth Circuit on the question of "whether the Ninth Circuit set forth the proper test for determining whether wetlands are 'waters of the United States' under the Clean Water Act, 33 U.S.C. 1362(7)." While the Court's ruling could have a significant impact on the scope of the Clean Water Act, there is no way to predict how the Court will rule in this case.

On January 19, 2017, the EPA issued the final 2017 construction general permit ("**CGP**") for stormwater discharges from construction activities involving more than one acre, which provides coverage for a five-year period and which took effect on February 16, 2017. The 2017 CGP implements Effluent Limitations Guidelines and New Source Performance Standards for the Construction and Development Industry. The rule includes stringent restrictions on erosion and sediment control, pollution prevention and stabilization.

The *Safe Drinking Water Act* (the "**SDWA**") and the Underground Injection Control ("**UIC**") program promulgated thereunder, regulate the drilling and operation of subsurface injection wells. The EPA directly administers the UIC program in some states and in others the responsibility for the program has been delegated to the state. The program requires that a permit be obtained before drilling a disposal well. Violation of these regulations and/or contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third-party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Many of the operators on the properties on which we hold our royalty interests employ hydraulic fracturing techniques to stimulate oil and natural gas production from unconventional geological formations, which entails the injection of pressurized fracturing fluids into a well bore. The federal *Energy Policy Act* of 2005 amended the SDWA to exclude hydraulic fracturing from the definition of "underground injection" under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, previously have been introduced in Congress, without success. However, with the changes in the U.S. presidential administrations and the control of Congress, such legislation may have a better chance of passing in the future. In addition, the EPA at the request of Congress conducted a national study examining the potential impacts of hydraulic fracturing on drinking water resources. The final report, *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States*, was issued in December 2016. The report raised some concerns regarding potential vulnerabilities in the process that could impact drinking water. However, the EPA noted that data gaps and uncertainties limited the agency's ability to draw conclusions about the impact of hydraulic fracturing activities on drinking water sources.

Many states currently independently regulate hydraulic fracturing operations in the state. If new federal rules or new state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly to perform fracturing and increase costs of compliance and doing business. It is also possible that drilling and injection operations could adversely affect the environment, which could result in a requirement to perform investigations or clean-ups or in the incurrence of other unexpected material costs or liabilities.

Over the past year, the Permian Basin has experienced an increase in seismic activity. According to seismologists, the most probable cause is the injection of saltwater into underground formations for disposal. This saltwater is produced in the oil and gas extraction process, separated from the oil and gas, and often disposed of underground. In response to such seismic activity, the Railroad Commission of Texas, which is responsible for regulating the exploration, production, and transportation of oil and natural gas in Texas, has implemented certain measures and may enact more with respect to saltwater disposal in the Permian Basin. In addition, in response to similar seismic activity in Oklahoma from 2010 and 2015, the regulatory authorities in Oklahoma established additional regulations and restrictions on produced water injection.

If oil and gas operators in the Permian Basin or other areas where Freehold has interests are unable to find alternative methods of disposal to formation injection, such operators may need to curtail hydrocarbon production pending implementation of a commercially reasonable solution, which could impact the operations of the Corporation's royalty payors.

The *Clean Air Act*, as amended, restricts the emission of air pollutants from many sources, including oil and gas operations. The *Clean Air Act* and regulations implemented thereunder regulate oil and natural gas production, processing, transmission and storage operations under the New Source Performance Standards ("**NSPS**") and National Emission Standards for Hazardous Air Pollutants programs. *Clean Air Act* regulations include NSPS for completions of hydraulically fractured wells. In 2016, the EPA issued rules to curb methane emissions and reduce the release of volatile organic compounds and toxic air pollutants from new and modified oil and gas sources ("**2016 Rule**"). The final rules covered emissions from additional equipment and activities in the oil production chain, including hydraulically fractured oil wells which were not previously regulated. Additionally, the rules required owners/operators to find and repair leaks to reduce fugitive emissions, which included increasing the frequency of monitoring equipment.

In September 2020, the EPA finalized the 2020 Rule that amended the 2016 Rule. In the 2020 Rule, EPA removed all sources in the transmission and storage segment of the oil and natural gas industry from regulation. The 2020 Rule also rescinded the methane requirements in the 2016 Rule and reduced monitoring frequencies. The 2020 Rule was challenged in the U.S. Court of Appeals for the D.C. Circuit, but in October 2020 the Court declined to issue a permanent stay of the 2020 Rule while it considered the merits of the challenge. The 2020 Rule, therefore, currently is in effect. However, in November 2021, the EPA announced that it is seeking information to inform a supplemental proposal to promulgate more stringent regulations on methane emissions in the oil and gas industry. The EPA intends to issue the supplemental proposal in 2022, and to issue a final rule before the end of 2022, which would require: 1) updated and broadened methane and VOC emission reduction requirements for new, modified, and reconstructed oil and gas sources, including standards that limit emissions from additional types of sources (such as intermittent vent pneumatic controllers, associated gas, and well liquids unloading); and 2) requirements that states develop plans to limit methane emissions from hundreds of thousands of existing sources nationwide, along with presumptive standards for existing sources to assist in the planning process. Key features of the proposed rule include:

- a comprehensive monitoring program for new and existing well sites and compressor stations;
- a compliance option that allows owners and operators the flexibility to use advanced technology that can find major leaks more rapidly and at lower cost;
- a zero-emissions standard for new and existing pneumatic controllers;
- standards to eliminate venting of associated gas, and require capture and sale of gas where a sales line is available, at new and existing oil wells;
- proposed performance standards and presumptive standards for other new and existing sources, including storage tanks, pneumatic pumps, and compressors; and
- a requirement that states meaningfully engage with overburdened and underserved communities, among other stakeholders, in developing state plans.

If this proposed rule is implemented, it would cause operators in the United States to incur increased operating expenses.

Operators in the United States are subject to a number of federal and state laws and regulations, including the federal *Occupational Safety and Health Act* ("**OSHA**") and comparable state laws, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal *Superfund Amendment and Reauthorization Act* and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Transportation and safety of natural gas is also subject to regulation by the U.S. Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration, under the *Natural Gas Pipeline Safety Act* of 1968, as amended, which imposes safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities, the *Pipeline Inspection, Protection, Enforcement and Safety Act of* 2006, the *Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011*, and the *Protecting our Infrastructure of Pipelines and Enhancing Safety Act* of 2020.

Operators in the United States are subject to federal and state laws and regulations relating to preservation and protection of historical and cultural resources. Such laws include the *National Historic Preservation Act*, the *Native American Graves Protection and Repatriation Act*, *Archaeological Resources Protection Act*, and the *Paleontological Resources Preservation Act*, and their state counterparts and similar statutes, which require certain assessments and mitigation activities if historical or cultural resources are impacted by our activities and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements.

Liability Management

Alberta

The AER administers the Liability Management Framework (the "**AB LM Framework**") and the Liability Management Rating Program (the "**AB LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. This change was effected under key new AER directives in 2021. Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the AB LM Framework and the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and the AB OWL Program fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LF Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), provides the backdrop for Alberta's approach to liability management. As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a licence transfer when any such licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed the *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes came into force in June 2020.

One important step in the shift to the AB LM Framework has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and granting of new well, facility and pipeline licences in Alberta are subject to AER approval. Previously under the AB LMR Program, as a condition of transferring existing AER licences, approvals and permits, all transfers required transferees to demonstrate that they had a liability management rating of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

Alongside changes to Directive 067, the AER also introduced *Directive 088: Licensee Life-Cycle Management* ("**Directive 088**") in December 2021 under the AB LM Framework. Directive 088 replaces, to an extent, the AB LLR Program with the AB LCA. Whereas the AB LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee's deemed asset value relative to the deemed liability value of its oil and gas wells and facilities, the AB LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. Such factors are wide reaching and include: (i) a licensee's financial health; (ii) its established total magnitude of liabilities, (iii) the remaining lifespan of its mineral resources; (iv) the management of its operations; (v) the rate of closure activities for its liabilities; and (vi) and its compliance with administrative and regulatory requirements. These various factors then feed into a broader holistic assessment of a licensee under the AB LM Framework. In turn, that holistic assessment provides the basis for assessing risk posed by licence transfers, as well as any security deposit that the AER may require from a licensee in the event that the regulator deems a licensee at risk of not being able to meet its liability obligations. However, the liability management rating under the AB LLR Program is still in effect for other liability management programs such as the AB OWL Program and the AB LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target.

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

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. In 2018, for example, the AER announced a voluntary area-based closure ("**ABC**") program. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets.

British Columbia

Similar to Alberta, the BC OGC oversees a Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the BC OGC determines the required security deposits for permit holders under the OGAA. The liability management rating is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed their deemed assets (i.e., an LMR below 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

Also similar to Alberta, the BC OGC has indicated that it will move away from the BC LMR Program and move towards a more holistic assessment under the new Permittee Capability Assessment program (the "**BC PCA**"). The BC PCA will include an evaluation of more than only a permittee's ratio of liabilities to assets. However, details regarding the BC PCA remain forthcoming. The BC OGC has indicated that the BC PCA will be implemented by April 2022.

In the spring of 2019, a liability-based levy paid to the Orphan Site Reclamation Fund ("**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 OGAA permits the BC OGC to impose more than one levy in a given calendar year.

The *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of 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 OGC, 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 Government of British Columbia passed amendments to the *Oil and Gas Activities Act* under the *Miscellaneous Statutes Amendment Act (No.2)* in October 2021. These amendments allow the BC OGC to grant exemptions for strict compliance with the requirements of the Dormancy Regulation. In turn, this may mean that a permit holder can, with approval, depart from the regulated timelines set under the Dormancy Regulation. The relevant amendments which provide the BC OGC with the power to grant these exemptions came into force on October 28, 2021.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"), which was updated in May 2020. The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan

Fund takes on the obligation of carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program also outlines requirements for security deposits and licence transfers. If a licence holder wishes to transfer a licence, then the transferee will be required to provide a security deposit if their licensee liability rating ("**LLR**") is not greater than 1.0. Other factors aside from the licensee's LLR may be considered when assessing the amount of the required security deposit.

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 licenced 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 licensee 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 oil and gas industry in response to COVID-19, in May 2020 the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. These funds were being administered by regulatory authorities in each province and disbursed through various provincial programs. The majority of these funds have now been allocated and disbursed.

Climate Change Regulation

Climate change regulation at each of the international, federal, provincial and state levels has the potential to significantly affect the future of the oil and gas industry. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow.

Canada

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. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

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, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

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. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of carbon dioxide equivalent ("**CO2e**") emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. This ensures that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reaches a maximum price of $50/tonne of CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Starting April 1, 2022, the minimum price permissible under the GGPPA is $50/tonne of CO2e. In addition, on March 5, 2021, the federal government introduced for comment the Greenhouse Gas Offset Credit System Regulations (Canada) (the "**Federal Offset Credit Regulations**"). The proposed Federal Offset Credit Regulations are intended to establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS. The final Federal Offset Credit Regulations are currently targeted for publication in mid-2022.

While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment release on March 25, 2021.

On April 26, 2018, the Canadian 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 oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that 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.

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

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced the $750 million Emissions Reduction Fund ("**ERF**"), intended to help the oil and gas sectors to reduce the production of methane and other GHG emissions. Funds disbursed through the ERF will primarily take the form of repayable contributions to onshore and offshore oil and gas firms. Of the $750 million in funding, $675 million was allocated to the Onshore Deployment Program, while $75 million was dedicated to the Offshore Deployment Program and the Offshore RD&D (research, development and demonstration) Program. Natural Resources Canada expects that all funding for onshore projects will be allocated by March 2022, while funding for offshore projects will be allocated by March 2023.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act* (the "**CNEAA**") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions-reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the Act came into force.

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. The federal government has indicated that urgent steps are necessary to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

Alberta

In November 2015, the Government of Alberta introduced a Climate Leadership Plan. In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emit roughly 70 megatonnes of GHG emissions per year, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On April 1, 2022, the carbon tax payable in Alberta will increase from $40 to $50 per tonne of CO2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved *Alberta's Technology Innovation and Emissions Reduction* ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial 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 in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which 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. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports. 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.

On September 1, 2020, the Government of Alberta announced $750 million in spending from the TIER fund to support projects that help industries reduce their carbon emissions. Such projects include CCUS, energy efficiency, and increased methane management initiatives. An additional $176 million in spending from the TIER fund was announced for similar GHG reduction projects on November 1, 2021.

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

British Columbia

In August 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. British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge is currently set at $45/tonne of CO2e. The charge will increase to $50/tonne of CO2e on April 1, 2022 and will continue to increase in line with the GGPPA minimum charge. Federal carbon pricing mechanisms are not currently in force in British Columbia, as the province's programs currently meet or exceed the federal benchmark stringency requirements.

In January 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.

In December 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 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 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. Complementing its CleanBC plan, on March 26, 2021, the Government of British Columbia announced a number of sector-specific emissions reduction targets, established with reference to 2007 emissions levels, that it aims to achieve by 2030, including reduction targets of 27% - 32% for the transportation sector, 38% - 43% for industry and 33% - 38% for oil and gas.

The Government of British Columbia established the CleanBC Industry Fund in 2019 to support clean industry development in the province. The fund uses a portion of carbon tax revenue paid by large emitters to invest in projects aimed at reducing greenhouse gas emissions. In March 2021, the Government of British Columbia temporarily increased the provincial share of funding to up to 90% of project costs with a cap of $25 million per project. As of November 2021, the CleanBC Industry Fund had invested $43 million in 32 projects across British Columbia.

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "**CleanBC Roadmap**"), aimed at helping British Columbia achieve its 2030 emission reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90% of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries, and for increased support for clean hydrogen and negative emissions technology.

Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

In January 2020, the BC OGC implemented 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. 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.

Saskatchewan

In May 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The government subsequently released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* ("**Prairie Resilience**"), outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program.

On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40% - 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO2e by 2030.

The MRGGA and the Saskatchewan O&G Emissions Regulations meet the federal benchmark stringency requirements for certain industrial sectors, but the federal backstop continues to apply to emissions sources not covered in Saskatchewan's emissions legislation. The federal fuel charge continues to apply in Saskatchewan.

In April 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the Province's progress on goals set out under Prairie Resilience. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030. According to its 2020 and 2021 reports, the province generates nearly 26% of its electricity from renewable energy sources, an increase of 1.6% since 2019.

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 in Saskatchewan. In furtherance of these goals and agreements, in March 2021, the Government of Saskatchewan announced it would provide $500,000 to support innovative research and technology for measuring and monitoring gas volumes and emissions, which will be overseen by the Saskatchewan Research Council.

In January 2021, the Government of Saskatchewan announced support for three projects expected to reduce methane emissions, including a new flare-gas-to-power project, an expansion of gas processing facilities, and a new gas fractionation plant. The Saskatchewan Petroleum Innovation Incentive ("**SPII**") and Oil and Gas Processing Investment Incentive ("**OGPII**") give this support. The SPII and OGPII provide a percentage of transferable royalty credits after private funding has been obtained and the facilities have been built.

In September 2021, Saskatchewan's Energy and Resource Minister announced that one of the government's key priorities would be increasing investment in CCUS through enhanced oil recovery CCUS projects.

Manitoba

In 2018, the Government of Manitoba unveiled the *Climate and Green Plan Implementation Act*. The 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. In March 2020, the Government of Manitoba introduced the *Climate and Green Plan Implementation Act, 2020*, which, among other things, introduced a $25/tonne of CO2e charge.

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.

In July 2020, Manitoba unveiled the Conservation and Climate Fund ("CCF"), which provides grants for green projects and initiatives. In October 2021, Manitoba announced $1 million in grants through the CCF to various organizations and projects, including methane clean tech development and electrification of vehicles and infrastructure.

United States

In the United States, on December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA developed and implemented regulations that restrict GHG emissions under existing provisions of the *Federal Clean Air Act* (the "**CAA**"), including one rule that limits GHG emissions from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("**PSD**") and Title V permitting programs. This rule "tailored" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. However, based on a decision of the U.S. Supreme Court, only facilities already required to obtain PSD permits for other criteria pollutants must also reduce GHG emissions that exceed certain thresholds consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis.

In June 2014, the Supreme Court upheld most of the EPA's GHG permitting requirements, allowing the agency to regulate the emission of GHG from stationary sources already subject to the PSD and Title V requirements. Certain oil and gas equipment and installations may currently be subject to PSD and Title V requirements and, hence, under the Supreme Court's ruling, may also be subject to the installation of controls to capture GHG. For any equipment or installation so subject, operators may have to incur increased compliance costs to capture related GHG emissions. In October 2016, the EPA proposed revisions to the rule applicable to GHGs for PSD and Title V permitting requirements. The proposed rule has not been finalized.

In addition, both houses of Congress have actively considered legislation to reduce GHG emissions and many states have already taken legal measures to reduce GHG emissions, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA issued regulations that limit GHG emissions associated with oil and gas operations, which will require operators to incur costs to inventory and reduce GHG emissions associated with operations and which could adversely affect demand for oil and natural gas.

Although the U.S. had withdrawn from the Paris Agreement, the Biden administration has issued executive orders recommitting the U.S. to the Paris Agreement and calling for the federal government to begin formulating the U.S.'s nationally determined emissions reduction goal under the agreement. With the U.S. recommitting to the Paris Agreement, additional executive orders may be issued or federal legislation or regulatory initiatives may be adopted to achieve the Paris Agreement's goals.

On January 27, 2021, the Biden administration also issued an executive order that commits to substantial action on climate change, calling for, among other things, suspending the issuance of new leases for oil and gas development on federal lands, pending completion of a review of leasing and permitting practices and expanding on the Acting Secretary of the U.S. Department of the Interior's January 20, 2020, order, effective immediately, that suspended new oil and gas leases and drilling permits on federal lands and waters for a period of 60 days. The executive order also called for the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and an increased emphasis on climate-related risks across government agencies and economic sectors. In June 2021, a federal judge in Louisiana blocked the administration's suspension of oil and gas leasing on federal lands and waters. In August 2021, the administration appealed that ruling, which is still pending. The Biden administration could also impose more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against fossil fuel producer companies in state or federal court, alleging that such companies created public nuisances by producing fuels that contributed to global warming effects.

The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations and financial results. In addition to the federal legislative and regulatory changes, in several U.S. states, the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to oil and gas facilities.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights 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 gas industry. In addition, Canada is a signatory to the *United Nations Declaration of the Rights of Indigenous Peoples* ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* (the "**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act 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 Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

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 Judy Desjarlais as Chief in January 2022, replacing Marvin Yahey Sr. in the role. The long-term impacts and risks of the Blueberry Decision and the election of a new BRFN Chief on the Canadian oil and gas industry remain uncertain.

Risk Factors

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation'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 Corporation's business and the oil and natural gas business generally.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation and its partners and royalty payors ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, 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, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation and its partners and royalty payors.

Oil and natural gas prices may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and conflicts in the Middle East. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation, its partners and royalty payor's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation and its partners and royalty payors might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Volatile 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 oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

See "*Industry Conditions – Transportation Constraints and Marketing*".

Russian Ukrainian Conflict

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Many countries throughout the world have provided aid to the Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the Russian invasion. The North Atlantic Treaty Organization ("**NATO**") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy.

In addition, certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. As part of the sanctions package, the German government paused the certificate process for the 1,200 km Nord Stream 2 natural gas pipeline that was built to carry natural gas from Russia to Germany. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply of energy and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflict and the sanction imposed on Russia remain uncertain.

Reliance on Third Parties

The Corporation relies on other companies drilling and producing from lands in which the Corporation has a royalty interest. The Corporation has very limited ability to exercise influence over the decision of companies to drill and produce from such lands in which the Corporation has a royalty interest. The Corporation's return on lands in which it has a royalty interest depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the capital expenditure budgets and financial resources of the operators who have a working interest in such lands, the ability to efficiently produce the resources from such lands and commodity prices.

In addition, companies that may have a working interest in the lands in which the Corporation has a royalty interest, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. Any reduction in the drilling and production from lands in which the Corporation has a royalty interest will negatively affect the Corporation's cash flows and financial results.

Any financial difficulty of companies which have assets in which the Corporation has a royalty interest may affect the Corporation'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 or insolvency. In addition, to the extent any companies who have assets in which the Corporation has a royalty interest go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency it is possible that the Corporation's royalty interest may not be (or may not be recognized as) an interest in land and as such the Corporation's royalty interest may not survive such bankruptcy or insolvency proceedings.

Freehold and Canpar Shared Mineral Title Ownership

Freehold and Canpar share mineral title ownership rights in a substantial land base in western Canada. Generally, Canpar owns mineral rights that were below the deepest producing formation at the time that Freehold was created in 1996, and Freehold holds the balance of the mineral rights. Freehold is not the legal registered owner of such mineral rights as Canpar holds these rights in trust for Freehold and receives the royalty payments in respect of such mineral rights on behalf of Freehold. Canpar currently holds mineral rights in trust for Freehold that represent approximately 10% of Freehold's total royalty revenue in 2019. As both Freehold and Canpar are both currently managed by Rife, collection of the royal payments that Canpar receives in trust for Freehold is managed by Rife. If the Management Agreement was terminated or Canpar was sold to a third party, although Canpar or the third party would still be obligated to hold such royalty payments in trust for Freehold, collection of such royalty payments may be delayed or be more challenging.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual or other obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry, generally, and of the Corporation's joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation 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 Corporation being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Take-in-Kind

All agreements that the Corporation has entered into that create a new royalty stipulate that the royalty interest so acquired by the Corporation is an interest in land and as such is separate and distinct from the interest of the royalty payor. In addition, all of these new royalty agreements provide the Corporation with the right, but not the obligation, to take its share of production in kind rather than have the royalty payor sell the Corporation's royalty production on behalf of the Corporation as agent for the Corporation. These provisions serve to mitigate the counter party risk attributable to any financial difficulty of the royalty payors under these agreements. The previously discussed provisions may not exist in certain of the royalty agreements previously entered into by other royalty recipients who subsequently sold their respective interest as a royalty recipient to the Corporation.

Exploration, Development and Production Risks

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

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

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced 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 revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour 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 Corporation.

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 material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation 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. See "*Risk Factors – Insurance*". In either event, the Corporation could incur significant costs.

Operational Dependence

Other companies operate most of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has a working interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management* ".

Title to and Right to Produce from Assets

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

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

Market Price of Common Shares

The trading price of securities of 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 Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. Also, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Political Uncertainty

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

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

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 oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Transportation Constraints and Market Access*".

COVID-19 and Its Effect on the Global Economy

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, liquids and natural gas. Since 2020, oil prices have largely recovered from their historic lows, but price support from future demand remains uncertain as countries experience varying degrees of virus outbreak and newly emerging virus variants following efforts to re-open local economies and international borders. Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on the Corporation's operational results and financial condition. Low prices for oil, liquids and natural gas will reduce the Corporation's funds from operations, and impact the Corporation's level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness, and temporary closures of the facilities of the Corporation or the royalty payors of the Corporation.

The extent to which the Corporation's operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond its control such as the duration and scope of the pandemic, additional actions taken by business and government in response to the pandemic, and the speed and effectiveness of responses to combat the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified herein, the extent of which is not yet known.

Project Risks

The ability of the Corporation and its royalty payors to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement and severe weather events, including fire, drought and flooding;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour;
- political uncertainty;
- environmental and indigenous activism that potentially results in delays or cancellations of projects; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all.

Gathering and Processing Facilities, Pipeline Systems, Trucking and Rail

The Corporation and its partners and royalty payors delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by truck and rail. The amount of oil and natural gas that the Corporation and its partners and royalty payors can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems, trucking and railway lines. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have 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 Corporation's ability to process its production and deliver the same to market. 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.

Reserves Estimates

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 document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

In accordance with applicable securities laws, the Corporation's independent 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 oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

Industry Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. In particular, the Corporation competes with other companies for the acquisition of royalty interests in oil and gas properties. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation and who may have lower costs of, and better access to, capital. The Corporation'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. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels 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 oil and natural gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flow by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Regulatory

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's and its partner's and royalty payor's costs, either of which may have a material adverse effect on the

Corporation's business, financial condition, results of operations and prospects. 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 oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

In order to conduct oil and natural gas operations, the Corporation and its partners' and royalty payors' will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation and its partners' and royalty payors' will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation'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*".

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of the Corporation's or its partners' or royalty payors' projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's or its partners' or royalty payors' operations, less economic. See "*Industry Conditions – Royalties and Incentives*".

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil, liquids and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing has resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. 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 Corporation's and its partners' and royalty payors' costs of compliance and doing business, as well as delay the development of oil, liquids and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions or bans on hydraulic fracturing in the areas where the Corporation has royalty interests could result in the Corporation being unable to economically recover its oil and gas reserves and reserves, which would result in a significant decrease in the value of the Corporation's assets.

Water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on the Corporation's royalty payors' ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact the operations of such royalty payors. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Corporation's royalty payors are unable to obtain water to use in their operations from local sources, they may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on the economics of such drilling resulting in delays or suspensions of drilling which ultimately would have a detrimental effect on the financial condition, results of operations, and cash flows of the Corporation.

In addition, the Corporation's royalty payors must dispose of the fluids produced from oil, liquids and natural gas production operations, including produced water, which it does directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. Over the past year, the Permian Basin has experienced an increase in seismic activity. According to seismologists, the most probable cause is the injection of saltwater into underground formations for disposal. This saltwater is produced in the oil and gas extraction process, separated from the oil and gas, and often disposed of underground. In response to such seismic activity, the Railroad Commission of Texas, which is responsible for regulating the exploration, production, and transportation of oil and natural gas in Texas, has implemented certain measures and may enact more with respect to saltwater disposal in the Permian Basin. In addition, in response to similar seismic activity in Oklahoma from 2010 and 2015, the regulatory authorities in Oklahoma established additional regulations and restrictions on produced water injection.

If oil and gas operators in the Permian Basin or other areas where Freehold has interests are unable to find alternative methods of disposal to formation injection, such operators may need to curtail hydrocarbon production pending implementation of a commercially reasonable solution, which could impact the operations of the Corporation's royalty payors.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Corporation's royalty payors or by commercial disposal well vendors that the Corporation's royalty payors may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Corporation's royalty payors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Corporation or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Corporation's business, financial condition, and results of operations.

Environmental

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

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

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.

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 Corporation'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 Corporation's profitability and a reduction in the value of its assets.

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 Corporation, for alleged personal injury, property damage, or other potential liabilities. While the Corporation 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 Corporation, 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 Corporation's management to dedicate significant time and resources to these climate change-related concerns, may adversely affect the Corporation's operations, the demand for and price of the Corporation's securities and may negatively impact the Corporation's cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance 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 Corporation 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 – Climate Change Regulation*"

Physical risks

Based on the Corporation'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 Corporation's royalty payors to access their properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions.

Inflation and Cost Management

The operating costs of the Corporation's royalty payors could escalate due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The inability of the Corporation's royalty payors to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows of the Corporation.

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

Variations in Foreign Exchange Rates and Interest Rates

World 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 oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the Common Shares of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition and development of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future acquisitions of royalty interests. The conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Corporation, to access additional financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash 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 Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to miss certain acquisition opportunities. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs.

As a result of global economic and political volatility, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause the Corporation to miss certain acquisition opportunities. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to acquire additional properties may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure or acquisition plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is determined by the Corporation and its lenders. The Corporation is required to comply with non-financial and financial covenants under its credit facility and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

If the Corporation's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms, or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under its credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

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

Hedging

Although the Corporation has never entered into hedges related to the expected future cash flow of royalty production, from time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation 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, the Corporation's hedging arrangements may expose it 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;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time, the Corporation 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 Corporation will not benefit from the fluctuating exchange rate.

The Corporation requires a Skilled Workforce

The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals by the Manager. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure by the Manager to implement the Corporation's business plans. The Manager competes with other companies in the oil and natural gas industry, as well as other industries, for this skilled workforce. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. If the Manager is unable to: (i) retain current employees; and/or (ii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Manager and correspondingly the Corporation could experience increased costs to retain and recruit these professionals.

If the Management Agreement is terminated, the Manager would cease to manage the operations of the Corporation and the Corporation would be required to ensure that it has sufficient staff to continue to carry on its business. There is no certainty that the Corporation would be able to hire or retain the necessary and appropriate staff to continue to manage the operations of the Corporation upon any termination of the Management Agreement. Any failure of the Corporation to recruit and retain the necessary and appropriate staff upon any termination of the Management Agreement, may negatively impact the Corporation.

Diluent Supply

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 may increase the Corporation's and its partners' and royalty payors' overall operating cost and result in decreased net revenues, negatively impacting the overall profitability of the Corporation's heavy oil and bitumen assets.

Insurance

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

The Corporation's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the Corporation to decide to reduce or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the Corporation's overall risk exposure could be increased and the Corporation could incur significant costs.

Geopolitical Risks

Political changes in North America and political instability in the Middle East, Europe and elsewhere may cause disruptions in the supply of oil that affects the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada, including the current conflict in the Ukraine and changes in political regimes or parties in power, may have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

Non-Governmental Organizations

The oil and natural gas exploration, development and operating activities conducted by the Corporation and its partners and royalty payors may, at times, be subject to public opposition. Such public opposition could expose the Corporation and its partners and royalty payors to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to 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, state or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Corporation and its partners and royalty payors will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation and its partners and royalty payors to incur significant and unanticipated capital and operating expenditures.

Reputational Risk Associated with the Corporation's Operations

The Corporation's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment toward, or in respect of, the Corporation'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 Corporation operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Corporation's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Similarly, our reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by our, or our partners' and royalty payors' operations. In addition, if we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultants to operate our business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact our reputation. See "*Risk Factors – Climate Change*".

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 our reputation. Damage to our reputation could result in negative investor sentiment towards Freehold, which may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our securities.

Changing Investor Sentiment

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

Indigenous Land and Rights Claims

Opposition by Indigenous groups of the operations, development or exploratory activities of oil and gas companies in any of the jurisdictions in which the Corporation has interests may negatively impact it in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact the Corporation's royalty payors' progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. Although there are no Indigenous and treaty rights claims on lands where the Corporation operates, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on its operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Corporation's royalty payors' ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, a recent British Columbia Supreme Court decision determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. Going forward, this 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. The long-term impacts of and associated risks of the decision on the Canadian oil and natural gas industry and the Corporation remain uncertain.

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See "*Industry Conditions – Indigenous Rights*".

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation, which may be dilutive to Shareholders.

Management of Growth

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

Expiration of Licenses and Leases

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

Dividends

The amount of future cash dividends paid by the Corporation, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, funds from operations, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements and debt levels, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Corporation, the dividend policy of the Corporation from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

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 Corporation and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Corporation 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 Corporation to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that the Corporation is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Litigation

In the normal course of the Corporation'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 personal injuries (including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes). The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation 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 affect on the Corporation's financial condition.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation 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.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable federal, provincial and state tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

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

During the year ended December 31, 2020, Freehold was reassessed by the CRA and denied the deduction of certain non-capital losses claimed and carried forward in tax returns filed for the years ended December 31, 2015, 2018 and 2019. Freehold is currently defending its tax filing position and expects it will be successful defending its position; however, if Freehold is not successful in defending its position Freehold may have additional tax liability owing to the CRA. For additional information, see "*Legal Proceedings and Regulatory Actions*".

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities, provincial and state transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production (or royalty production) if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of muskeg. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict access to properties in which the Corporation has an interest and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation.

Information Technology Systems and Cyber-Security

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

Further, the Corporation 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 Corporation'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 our business activities or our 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 Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information, or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Manager'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 Manager'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.

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 Corporation's systems and obtain confidential information.

The Corporation maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. The Corporation also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Corporation's efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage its information technology infrastructure. The Corporation 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 our performance and earnings, as well as on our reputation, and any damages sustained may not be adequately covered by the Corporation'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 Corporation's business, financial condition and results of operations.

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies 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 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 with the Corporation to 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. See "*Conflicts of Interest*".

Reliance on Key Personnel

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

All of the Corporation's key personnel are employees of the Manager. If the Management Agreement is terminated, the Manager would cease to manage the operations of the Corporation and the Corporation would be required to ensure that it has sufficient staff to continue to carry on its business. There is no certainty that the Corporation would be able to hire or retain the necessary and appropriate staff to continue to manage the operations of the Corporation upon any termination of the Management Agreement. Any failure of the Corporation to recruit and retain the necessary and appropriate staff upon any termination of the Management Agreement, may negatively impact the Corporation.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on acquiring and managing oil and natural gas royalties in both Canada and the United States and developing and producing its working interest oil and gas assets in Canada. In the future, the Corporation may acquire or move into new industry related activities or new geographical areas, including potentially new areas in the United States and may acquire different energy related assets; as a result, the Corporation may face unexpected risks or, alternatively, its exposure to one or more existing risk factors may be significantly increased, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

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

Additional information on the risks, assumption and uncertainties are found under the heading "*Advisories – Cautionary Statement Regarding Forward-Looking Information and Statements*" of this Annual Information Form.

Description of Capital Structure

The authorized capital of Freehold consists of an unlimited number of Common Shares and 10,000,000 Preferred Shares. As of the date hereof, there are 150,612,334 Common Shares and no Preferred Shares 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

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Freehold. Subject to the prior satisfaction of all preferential rights attached to other classes of shares of Freehold, the holders of Common Shares are entitled to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of Freehold upon its dissolution or winding-up.

Preferred Shares

The Preferred Shares are issuable in one or more series and the Board of Directors may fix their issue, the number of shares of each series and the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares. The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets or the return of capital in the event of the liquidation, dissolution or winding-up of Freehold, rank on a parity with the Preferred Shares of every other series and are entitled to a preference over the Common Shares and any other shares of Freehold ranking junior to the Preferred Shares.

Other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Shares, the voting rights attached to the Preferred Shares shall be limited to one vote per Preferred Share at any meeting where the Preferred Shares, if any, and Common Shares vote together as a single class.

Market for Securities

Common Shares

The Common Shares are listed and trade on the TSX under the symbol "FRU". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the Common Shares on the TSX for the periods indicated:

TORONTO STOCK EXCHANGE
COMMON SHARES TRADING RANGE

	(Cdn$ per Common Share)			
	High	Low	Close	Volume Traded
2021				
January	6.30	5.18	5.48	9,036,383
February	7.37	5.51	6.90	11,196,874
March	8.10	6.87	7.25	11,468,506
April	8.08	7.15	8.05	7,654,250
May	9.61	8.03	9.03	10,041,623
June	9.91	9.04	9.77	7,352,062
July	10.56	8.02	8.73	10,957,423
August	9.80	8.125	9.46	10,917,086
September	10.50	9.18	10.40	15,186,374
October	12.33	10.33	11.83	15,315,924
November	13.17	10.49	10.88	19,390,847
December	11.81	10.03	11.65	20,969,526
2022				
January	13.15	11.30	13.15	16,790,132
February	14.17	12.97	14.15	12,707,794
March 1	14.70	14.17	14.34	1,548,163

Prior Sales

Other than Deferred Share Units, Freehold did not issue any securities of a class that are not listed or quoted on the market place during the year ended December 31, 2021.

We issued the following Deferred Share Units (including notional Deferred Share Units resulting from dividends) redeemable to acquire an equal number of Common Shares (less tax withholding) pursuant to the Deferred Share Unit Plan during the year ended December 31, 2021:

Date	Numbered Deferred Share Units	Deemed Price per Deferred Share Unit
January 1, 2021	93,088	$5.21
January 15, 2021	1,035(1)	$6.29
February 15, 2021	1,348(1)	$6.23
March 15, 2021	1,111(1)	$7.58
March 30, 2021	2,786(2)	$7.29
April 15, 2021	1,635(1)	$7.80
May 17, 2021	1,406(1)	$9.10
June 15, 2021	1,818(1)	$9.42
June 30, 2021	2,056(2)	$9.71
July 15, 2021	1,864(1)	$9.27
August 15, 2021	1,926(1)	$9.01
September 15, 2021	2,251(1)	$9.68
September 29, 2021	1,965(2)	$10.02
October 15, 2021	1,893(1)	$11.62
November 15, 2021	1,756 (1)	$12.68
December 15, 2021	2,413(1)	$11.03
December 30, 2021	1,702(2)	$11.57

(1) Issued as notional Deferred Share Units resulting from the payment of dividends of the Common Shares.
(2) Issued in lieu of quarterly directors' fees based on directors' elections.

Escrowed Securities

To our knowledge, none of our securities are held in escrow.

Dividends

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2021, our legal stated capital was $360 million.

Monthly dividends of Freehold are currently declared for Shareholders of record as of the last day of each month and are paid on or about the 15th day of the following month. The dividends are "eligible dividends" for income tax purposes and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of Common Shares. The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, income taxes and the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board of Directors reviews the dividend policy quarterly and at its discretion, any excess income available for dividends may be directed toward repayment of long-term debt and improvements in working capital.

Record of Cash Dividends

Since January 1, 2022, Freehold has declared a cash dividend of $0.06 per Common Share for Shareholders of record on January 31, 2022, which was paid on February 15, 2022, has declared a cash dividend of $0.06 per Common Share for Shareholders of record on February 28, 2022, which is payable on March 15, 2022, and has declared a cash dividend of $0.08 per Common Share for Shareholders of record on March 31, 2022, which is payable on April 18, 2022.

The tables below set forth the amount of cash dividends paid on the Common Shares during the three most recently completed financial years:

Record Date	Payment Date	Cdn$ per Share
2019		
January 31, 2019	February 15, 2019	0.0525
February 28, 2019	March 15, 2019	0.0525
March 31, 2019	April 15, 2019	0.0525
April 30, 2019	May 15, 2019	0.0525
May 31, 2019	June 15, 2019	0.0525
June 30, 2019	July 15, 2019	0.0525
July 31, 2019	August 15, 2019	0.0525
August 30, 2019	September 16, 2019	0.0525
September 30, 2019	October 15, 2019	0.0525
October 31, 2019	November 15, 2019	0.0525
November 30, 2019	December 16, 2019	0.0525
December 31, 2019	January 15, 2020	0.0525
		0.6300

Record Date	Payment Date	Cdn$ per Share
2020		
January 31, 2020	February 18, 2020	0.0525
February 29, 2020	March 16, 2020	0.0525
March 31, 2020	April 15, 2020	0.0525
April 30, 2020	May 15, 2020	0.0150
May 31, 2020	June 15, 2020	0.0150
June 30, 2020	July 15, 2020	0.0150
July 31, 2020	August 17, 2020	0.0150
August 31, 2020	September 15, 2020	0.0150
September 30, 2020	October 15, 2020	0.0150
October 31, 2020	November 16, 2020	0.0150

November 30, 2020	December 15, 2020	0.0150
December 31, 2020	January 15, 2021	0.0150
		0.2925

Record Date	Payment Date	Cdn$ per Share
2021		
January 31, 2021	February 15, 2021	0.0200
February 28, 2021	March 15, 2021	0.0200
March 31, 2021	April 15, 2021	0.0200
April 30, 2021	May 15, 2021	0.0300
May 31, 2021	June 15, 2021	0.0300
June 30, 2021	July 15, 2021	0.0400
July 31, 2021	August 15, 2021	0.0400
August 30, 2021	September 16, 2021	0.0400
September 30, 2021	October 15, 2021	0.0500
October 31, 2021	November 15, 2021	0.0500
November 30, 2021	December 16, 2021	0.0500
December 31, 2021	January 15, 2022	0.0600
		0.4500

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, Freehold believes it should 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. Freehold, in order to allow Shareholders the ability to make a Qualified Electing Fund election, 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 Freehold.

Direct Deposit Plan

A direct deposit plan has been established for Freehold to provide holders who have Canadian bank accounts with a method of receiving cash dividends as a direct deposit into their bank account.

U.S. Currency Payment Plan

The U.S. currency payment plan allows our holders of Common Shares who maintain U.S. currency accounts to obtain payments in U.S. currency.

Directors and Officers

General

Subject to the ultimate authority of the Board of Directors, Freehold, FHT and the Partnership are managed by the Manager.

Governance Agreement

The Governance Agreement provides that if the Manager and its affiliates, including the CN Pension Trust Funds, hold 10% or more of the issued and outstanding Common Shares, the Manager will have the right to nominate for election two individuals as directors of Freehold. If the Manager and its affiliates hold less than 10% of the issued and outstanding Common Shares, the Manager will have the right to nominate for election one individual as a director of Freehold. If the individuals nominated by the Manager fail to get elected or if the Manager ceases to hold any Common Shares (in which case the Manager will not have the right to nominate any individuals as directors of Freehold) but continues to act as manager of Freehold pursuant to the Management Agreement, the Governance Agreement will provide the Manager with the right to have an observer present at all meetings of directors of Freehold. The CN Pension Trust Funds holds, directly or indirectly, approximately 18.08% of the outstanding Common Shares and as a result, has the right to nominate two individuals as directors of Freehold.

Decision Making

Although the Manager provides certain advisory and management services to Freehold pursuant to the Management Agreement, the Board of Directors supervises the management of the business and affairs of Freehold. In particular, all decisions relating to: (a) issuances of additional securities of Freehold; (b) the acquisition and disposition of properties of Freehold, and its subsidiaries and partnerships for a purchase price or proceeds in excess of $10 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities and hedging; and (e) the payment of dividends to Shareholders of Freehold, are made by the Board of Directors. Any amendment to the Management Agreement requires the approval of the Board of Directors. The Board of Directors hold regularly scheduled meetings to review the business and affairs of Freehold and make any necessary decisions relating thereto.

Board of Directors of Freehold

As at March 2, 2022, the Board of Directors was comprised of nine individuals. The name, province of residence, position held and principal occupation of each director of Freehold are as follows:

Name and Province of Residence	Position with Freehold	Principal Occupation	Director Since
Gary R. Bugeaud(1)(2) Alberta, Canada	Director	Corporate Director	May 14, 2015
Peter T. Harrison(4) Quebec, Canada	Director	Manager, Resource and Royalties CN Investment Division	July 29, 1996(5)
Maureen E. Howe(1) British Columbia, Canada	Director	Corporate Director	February 1, 2022
J. Douglas Kay(2)(3) Alberta, Canada	Director	Corporate Director	May 11, 2016
Arthur N. Korpach(1)(2) Alberta, Canada	Director	Corporate Director	May 9, 2012
Susan M. MacKenzie(2)(3) Alberta, Canada	Director	Corporate Director	May 14, 2014
Marvin Romanow Alberta, Canada	Chair of the Board	Corporate Director	May 14, 2015
David M. Spyker(4) Alberta, Canada	President and Chief Executive Officer and Director	President & Chief Executive Officer of Rife	January 20, 2021
Aidan M. Walsh(1)(3) Alberta, Canada	Director	Corporate Director	May 15, 2013

(1) Member of Audit Committee.
(2) Member of Governance, Nominating and Compensation Committee.
(3) Member of Reserves Committee
(4) Directors nominated for election at the last annual meeting of Shareholders held on May 11, 2021 by the Manager pursuant to the Governance Agreement.
(5) Reflects the date of election or appointment as a member of the board of directors of Freehold Resources Ltd. prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

Officers of Freehold

The following table sets forth the name, province of residence, position held and principal occupation of each of the officers of Freehold:

Name and Province of Residence	Position with Freehold	Principal Occupation	Officer Since
David M. Spyker Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Rife	November 28, 2016
David W. Hendry Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Rife	December 1, 2019
Lisa N. Farstad Alberta, Canada	Vice President, Corporate Services	Vice President, Corporate Services of Rife	March 1, 2020
Ian C. Hantke Alberta, Canada	Vice President, Diversified Royalties	Vice President, Diversified Royalties of Rife	January 1, 2022
Robert A. King Alberta, Canada	Vice President, Business Development	Vice President, Business Development of Rife	January 6, 2020
Robert E. Lamond Alberta, Canada	Vice President, Asset Development	Vice President, Asset Development of Rife	September 5, 2017
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary of Rife	February 27, 2008[1]

(1) Reflects the date of appointment as an officer of Freehold Resources Ltd. prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

Except as described in the detailed biographies of each of the directors and officers set forth below, each of the directors and officers of Freehold has been engaged in his or her principal occupation or in other capacities with the same firm or organization for the past five years.

As at March 2, 2022, the directors and senior officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 521,276 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 27,227,464 Common Shares (approximately 18.08%) as at March 4, 2022. From 1996 to March 4, 2022, the Manager has received 3,810,450 Common Shares in payment of the Management Fee.

The following is a brief description of the backgrounds of the directors and officers of Freehold.

Gary R. Bugeaud

Mr. Bugeaud is a Corporate Director and was the Managing Partner of Burnet, Duckworth & Palmer LLP until his retirement in December 2013. He has over 23 years of legal experience focused on securities, corporate finance, mergers and acquisitions, and corporate governance matters. Mr. Bugeaud has a Bachelor of Commerce (Finance) degree and a Bachelor of Laws degree from the University of Saskatchewan. Mr. Bugeaud holds the ICD.D designation from the Institute of Corporate Directors.

Peter T. Harrison

Mr. Harrison is Manager, Resource and Royalties of the CN Investment Division (Montreal), which manages one of the largest corporate pension funds in Canada. Mr. Harrison has spent over 40 years analyzing business models and investing in public companies. Having managed multi-billion dollar equity portfolios and voted proxies for many years, he brings a deep understanding of investor concerns to the Board. He has been a director of several public and private companies. He has a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario, and is a Chartered Financial Analyst. He is a member of the Institute of Corporate Directors.

Maureen E. Howe

Ms. Howe is a Corporate Director with substantial finance and capital market experience as well as relevant public company experience. Formerly a Managing Director, Equity Research, Energy Infrastructure at RBC Capital Markets, she specialized in the area of energy infrastructure, which included power generation, transmission and distribution, oil and gas transmission and distribution, gas processing and alternative energy. Prior to joining RBC Capital Markets, Ms. Howe held various positions in the area of capital markets, including investment banking, underwriting, project analysis, portfolio management, investment relations, and corporate finance. Ms. Howe is a director of Methanex Corporation and Pembina Pipeline Corporation, and is Chair of the University of British Columbia Sauder School of Business Phillips, Hager & North Centre for Financial Research. Ms. Howe holds a Bachelor of Commerce (Honours) from the University of Manitoba and a Ph.D. in Finance from the University of British Columbia. She is a member of the Institute of Corporate Directors.

J. Douglas Kay

Mr. Kay is a Corporate Director and an experienced oil and gas industry executive with strong land, finance, negotiating and leadership skills. He has over 40 years of diverse responsibilities with Canadian based oil and gas exploration and production companies. Mr. Kay holds a Bachelor of Economics degree from the University of Calgary, is a graduate of the Management Development Program of the University of Western Ontario, and holds the designation of P. Land through the Canadian Association of Petroleum Landmen (CAPL). Mr. Kay holds the ICD.D designation from the Institute of Corporate Directors. He currently serves on the board of Westbrick Energy Ltd. as Chairman and is a former director and Chair of the Explorers and Producers Association of Canada (EPAC).

Arthur N. Korpach

Mr. Korpach is a Corporate Director. He has four years of public company audit and 27 years of investment banking experience, with a focus on the energy sector. His experience includes providing advice on strategy, business plans, capital structure, credit strategy, financing, and mergers and acquisitions. He has advised clients on over 300 transactions. Mr. Korpach is a Fellow Chartered Accountant and a Chartered Business Valuator. Mr. Korpach is a past chair of the Accounting Standards Board of the Institute of Chartered

Professional Accountants. He has a Bachelor of Commerce degree from the University of Saskatchewan and an MBA from Harvard Business School. Mr. Korpach holds the ICD.D designation from the Institute of Corporate Directors.

Susan M. MacKenzie

Ms. MacKenzie is a Corporate Director, independent consultant and former oil and gas industry executive with over 25 years of energy sector experience in operations and service support areas. She has a proven track record in the areas of governance, strategy development, organizational alignment, operational execution and project management, and she has demonstrated success in corporation-wide policy development and implementation. Ms. MacKenzie holds a Bachelor of Engineering (Mechanical) degree from McGill University and an MBA from the University of Calgary. She is a Life member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Ms. MacKenzie holds the ICD.D designation from the Institute of Corporate Directors. She is a director of Enerplus Corporation, MEG Energy Corporation, and Precision Drilling Corporation.

Marvin F. Romanow

Mr. Romanow is a Corporate Director, Executive in Residence at the University of Saskatchewan, and former oil and gas industry executive with over 30 years of experience. He has a proven track record in the areas of operating, financial and strategic leadership. His executive roles provided direct engagement with shareholders and directors at two major public corporations over the past 20 years. Mr. Romanow is a graduate of Harvard's Program for Management Development and in October 2007 he completed INSEAD's Advance Management Programme. He has an MBA and a Bachelor of Engineering, with Great Distinction, from the University of Saskatchewan. Mr. Romanow holds the ICD.D designation from the Institute of Corporate Directors. He currently serves on the board of the Arnie Charbonneau Cancer Institute.

Aidan M. Walsh

Mr. Walsh is a Corporate Director. Prior to April 30, 2020 he was Chief Executive Officer of Baccalieu Energy Inc. (Calgary), a private junior oil and gas company that he co-founded in 2008. Mr. Walsh has over 43 years of oil and gas experience in production, marketing, transportation, acquisitions, finance, facility engineering, and construction. He is a proven negotiator and a strategic thinker with strong leadership and analytical skills. He has experience interacting with industry partners as well as regulators and federal and provincial government representatives on issues affecting the Canadian oil and gas industry. Mr. Walsh has a Bachelor of Engineering degree in Mechanical Engineering from Memorial University of Newfoundland and a Masters of Business Administration degree from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Walsh holds the ICD.D designation from the Institute of Corporate Directors. He is a former director and Chair of the Explorers and Producers Association of Canada (EPAC).

David M. Spyker

Mr. Spyker was appointed President and Chief Executive Officer in January 2021. From September 2020 to January 2021 Mr. Spyker served as Freehold's Interim President and Chief Executive Officer. Mr. Spyker joined Rife in November 2016 as Vice President, Production and was appointed Chief Operating Officer in

March 2019. Prior to joining Rife, he held various roles at Anderson Exploration Ltd., Anderson Energy Ltd., and Anderson Energy Inc. Mr. Spyker has over 30 years of industry experience. He holds a Bachelor of Science degree in Mechanical Engineering from the University of Alberta and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). He is a member of the Institute of Corporate Directors.

David W. Hendry

Mr. Hendry is our Vice President, Finance and Chief Financial Officer. He joined Rife in December 2019. Prior to joining Rife, Mr. Hendry served as Chief Financial Officer of Obsidian Energy Ltd. from January 2017 to November 2019 and served as Vice President, Finance of Obsidian Energy Ltd. from May 2015 to December 2016. Mr. Hendry served as Vice President, Finance of Talisman Energy Inc. from August 2009 to April 2015. Mr. Hendry is a Chartered Professional Accountant with over 30 years of finance experience. Mr. Hendry has a Bachelor of Commerce degree from the University of Calgary.

Lisa N. Farstad

Ms. Farstad was appointed Vice President, Corporate Services in March 2020. She joined Rife in September of 2015 as Manager, Human Resources and Information Services. Prior to joining Rife, Ms. Farstad spent 14 years with Bonavista Energy Corporation in various human resources roles including Manager, Human Resources. Ms. Farstad has a Bachelor of Arts degree from the University of Calgary and a HR Management Certificate from the University of Calgary.

Ian C. Hantke

Mr. Hantke was appointed Vice President, Diversified Royalties on January 1, 2022. He joined Rife in February 2014, and held various roles within the Business Development Group, most recently Director, Acquisitions. Prior to joining Rife, Mr. Hantke spent two years working at Devon Energy as a Project Manager and seven years working at O'Rourke Engineering as a Facilities Engineer. Mr. Hantke has a Bachelor of Aerospace Engineering degree from Carleton University and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Robert A. King

Mr. King is our Vice President, Business Development. He joined Rife in January 2020, and was, prior thereto, Managing Director at RBC Capital Markets. Mr. King has over 20 years' experience in investment banking where he has spent the entirety of his career progressing through roles of increasing accountability and responsibility. He possesses significant merger, acquisition and divestiture and capital markets experience with a focus on upstream oil and gas. Mr. King has a Bachelor of Commerce degree from the University of Calgary.

Robert E. Lamond

Mr. Lamond is our Vice President, Asset Development. He joined Rife in September 2017. He previously held various geoscience and managerial roles at Murphy Oil Corporation, Shell Canada Ltd., and Imperial Oil Ltd. Most recently he held the role of General Manager, Geoscience at Murphy Oil. Mr. Lamond holds a

Bachelor of Science degree in Geology from Queen's University and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Karen C. Taylor

Ms. Taylor is our Corporate Secretary. Ms. Taylor joined Rife in February 1997 and was appointed Corporate Secretary in February 2008. Ms. Taylor is a member of the Governance Professionals of Canada (GPC).

Corporate Cease Trade Orders or Bankruptcies

Except as described below, during the past ten years, none of the current directors and executive officers of Freehold 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; (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. None of the directors or executive officers of Freehold is as at the date of the annual information form, or has been within 10 years before the date of the information circular, 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. Harrison was a director of Spyglass Resources Ltd. ("**Spyglass**") and resigned on November 26, 2015. Spyglass was placed into receivership on November 26, 2015. The common shares of Spyglass were suspended from trading on the TSX on December 31, 2015. The Alberta Securities Commission and certain other securities regulatory authorities in Canada issued cease trade orders against Spyglass in May 2016.

Mr. Harrison was a director of Delphi Energy Corp. ("**Delphi**") and resigned on September 23, 2019. On April 14, 2020, Delphi commenced proceedings under the *Companies' Creditors Arrangement Act*.

Personal Bankruptcies

None of the directors or executive officers of Freehold has nor any Shareholder holding sufficient number of securities of Freehold to affect materially the control of Freehold, within the past 10 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 Freehold nor any Shareholder holding sufficient number of securities of Freehold to affect materially the control of Freehold, 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

The full text of the audit committee mandate is included in Appendix C of this AIF.

Composition of Audit Committee

Freehold's audit committee consists of Mr. Arthur Korpach (Chair), Mr. Gary Bugeaud, Ms. Maureen Howe, and Mr. Aidan Walsh. 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 Officers*".

Pre-Approval Policies and Procedures

The audit committee pre-approves all non-audit services to be provided to Freehold by the external auditors. Prior to the commencement of Freehold's fiscal year, the audit committee pre-approves expenditures with a dollar limit for services related to consultations as to the accounting or disclosure treatment of transactions, and for expenditures with a dollar limit for services related to taxation matters. The audit committee must pre-approve any costs that exceed these limits.

External Auditor Service Fees

The following table sets out the fees for KPMG LLP, our external auditor, in the two most recently completed financial years.

	Year Ended December 31	
	2021	2020
Audit fees(1)	415,695	303,880
Audit-related fees(2)	-	-
Tax fees(3)	35,719	51,181
All other fees	-	-
Total	451,414	355,061

(1) Freehold's annual financial statements, reviews of interim consolidated financial statements for the first, second, and third quarters of the respective year, or services that are normally provided in connection with statutory and regulatory filings or engagements including the filings of prospectuses by the Corporation in respect of public financings completed by the Corporation. Fees do not include administrative or Canadian Public Accountability Board surcharges.

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

(3) Tax fees consist of fees for tax compliance, tax preparation and advisory services. During 2021 and 2020, $12,500 and $12,500, respectively, of such fees were related to tax compliance and tax preparation and the remainder was for advisory services.

The Manager

Business of the Manager

The Manager provides comprehensive oil and gas company management and operational services to Freehold, FHT, and the Partnership. The Manager is a wholly-owned subsidiary of Rife. Pursuant to an agreement between Rife and the Manager dated November 25, 1996, Rife provides the Manager, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to Freehold, FHT and the Partnership.

Employees

Freehold has no employees but rather is managed by the Manager pursuant to the Management Agreement. On December 31, 2021, Rife had 85 full and part-time employees in the Calgary office and 9 full-time employees in their field operations, the majority of whom are on contract to the Manager. These personnel also render services to Rife and Canpar.

Management Agreement

Pursuant to the Management Agreement, Freehold, FHT and the Partnership engaged the Manager to:

- administer all matters relating to the securities of Freehold, including the Common Shares, and the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold, FHT and the Partnership, including: (i) determining the total amount owing to Freehold and its subsidiaries and partnerships from third parties and conducting joint venture audits as required; (ii) determining the total amounts owing to Shareholders and arranging for dividends to Shareholders, subject to the supervision of Freehold; (iii) providing Shareholders with periodic reports on the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold and its subsidiaries and partnerships; and (iv) providing Shareholders with financial reports and tax information relating to the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold and its subsidiaries and partnerships;

- provide management services for the economic and efficient exploitation of oil and natural gas properties;

- operate oil and natural gas properties that Freehold and its subsidiaries and partnerships are entitled to operate and monitor the activities of third party operators;

- recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for Freehold and its subsidiaries and partnerships;

- negotiate on behalf of Freehold and its subsidiaries and partnerships all exploitation and development agreements, operating agreements, working agreements, farmin and farmout agreements, leases and other documents relating to the exploitation of the oil and natural gas properties as may be advisable;

- recommend and negotiate banking arrangements for Freehold; and

- provide office space, office furnishings and equipment and personnel necessary for the proper administration of the assets of Freehold and its subsidiaries and partnerships.

In exercising its power and discharging its duties under the Management Agreement, the Manager will be required to exercise that degree of care, diligence and skill that a reasonably prudent advisor and manager in respect of oil and gas properties in western Canada would exercise in comparable circumstances.

The Management Agreement will continue in force until terminated by either the Manager or Freehold in accordance with the terms of the Management Agreement. Either the Manager or Freehold can terminate the Management Agreement at any time by providing six months written notice prior to the date of such termination. In addition, if a "Change of Control" (as defined in the Management Agreement) of Freehold occurs, Freehold will have the right to terminate the Management Agreement by providing written notice to the Manager within 90 days of such Change of Control together with making a payment to the Manager of $2,000,000.

Freehold may also terminate the Management Agreement at any time without the payment of compensation to the Manager if the Manager institutes bankruptcy proceedings, seeks relief under bankruptcy law, consents to the appointment of a receiver, voluntarily suspends transaction of its usual business, is declared bankrupt or insolvent, if a receiver is appointed in respect of the Manager, or if the Manager fails to carry out its material obligations under the Management Agreement and does not commence to cure such failure within 30 days of notice being given.

Proceeds relating to subscription offerings, Royalty Income and other revenues generated from or associated with any interest of Freehold may not be commingled with the funds of any other entity that is managed by the Manager.

The Manager will be paid the Management Fee for providing all of the management services. The Manager will be indemnified by Freehold in respect of certain damages that it may suffer in discharging its obligations under the Management Agreement provided that such damages do not arise from the fraud, wilful default, gross negligence or bad faith of the Manager.

The Board of Directors will review on an ongoing basis both the nature and extent of the services required of the Manager and the costs of providing the same. All amendments to the Management Agreement must be approved by a majority of the members of the Board of Directors.

Compensation

The Manager will be compensated as follows for providing services to Freehold, FHT and the Partnership.

Management Fee

Under the terms of the Management Agreement, the Manager is issued Common Shares quarterly as payment of the Management Fee. In 2019, 2020 and 2021 an aggregate of 220,000, 165,000 and 110,000 Common Shares, respectively, were issued to the Manager as payment of the Management Fee. As at December 31, 2021, the quarterly Management Fee was 27,500 Common Shares.

Under the terms of the Management Agreement, the Common Shares issuable as payment of the Management Fee will be gradually reduced over the next several years, as follows:

- in 2022 the Common Shares issuable on payment of the Management Fee will be capped at 13,750 Common Shares paid quarterly; and

- in 2023 and beyond the Common Shares issuable on payment of the Management Fee will be capped at 5,500 Common Shares paid quarterly.

In addition, the Management Agreement provides a mechanism for reducing the number of Common Shares issuable as payment of the Management Fee if the market price of the Common Shares at such time exceeds $19.00 per Common Share. Pursuant to the Management Agreement, the Management Fee, at the option of Freehold, may be paid by (i) the issuance of Common Shares, or (ii) cash equal to the value of such Common Shares as determined by the market price of such Common Shares at such time.

General and Administrative Costs

The Manager is reimbursed for general and administrative costs incurred by Rife on behalf of Freehold, FHT and the Partnership (in 2021 – 53%). General and administrative costs are generally charged to Freehold, FHT and the Partnership by the Manager based on time spent and direct costs incurred in fulfilling the obligations of the Manager to Freehold, FHT and the Partnership pursuant to the Management Agreement. Commencing in 2017, the allocation of costs based on time spent is adjusted quarterly based on the actual percentage for the allocation of time spent by Rife's staff in the prior quarter (previously, the adjustment was only made once annually).

Effective July 1, 2019, Rife entered into a new office lease. Concurrently with Rife entering into the new office lease, Freehold and Rife entered into an office lease sharing agreement pursuant to which Freehold is responsible for its proportional share of the new office lease based on the allocation of general and administrative costs between Freehold and Manager in accordance with the Management Agreement provided that the minimum percentage of the office lease that Freehold will be responsible for is 40% and the maximum percentage of the office lease that Freehold will be responsible is 60%.

Long-Term Incentive Plan

Since 2017, Freehold's proportionate share of long-term incentive compensation consisted of grants of performance awards and restricted awards under Freehold's incentive award plan. In 2021, a total of 195,915 (2020 – 308,167) restricted awards and 233,540 (2020 – 363,480) performance awards were granted to employees of Rife under the Freehold incentive award plan reflecting Freehold's 54% (2020 – 48%) of long-term incentive compensation granted to Rife employees in 2021. Restricted awards and performance awards accumulate the full value of Freehold's monthly dividend and upon vesting, the payout amount is adjusted to reflect these dividends and, in the case of performance awards, a performance multiplier based on certain applicable Freehold performance factors.

Manager's Annual Bonus Plan

We pay our proportionate share (2021 – 53%) of annual cash bonuses paid under the Rife short-term incentive plan for employees of the Manager.

Directors' Deferred Share Unit Plan

The Deferred Share Unit Plan consists of fully vested Deferred Share Units, granted annually to our non-management directors. Dividends to Shareholders we declare prior to redemption are assumed to be reinvested in notional share units on the date of dividend.

Directors and Officers of the Manager

The name, province of residence, position held and principal occupation of each director and officer of the Manager are set out below:

Name and Province of Residence	Position with the Manager	Principal Occupation	Director or Officer of the Manager Since
David M. Spyker Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Rife	November 28, 2016
David W. Hendry Alberta, Canada	Vice President, Finance and Chief Financial Officer and Director	Vice President, Finance and Chief Financial Officer of Rife	December 1, 2019
Lisa N. Farstad Alberta, Canada	Vice President, Corporate Services	Vice President, Corporate Services of Rife	March 1, 2020
Ian Hantke Alberta, Canada	Vice President, Diversified Royalties	Vice President, Diversified Royalties of Rife	January 1, 2022
Robert A. King Alberta, Canada	Vice President, Business Development	Vice President, Business Development of Rife	January 6, 2020
Robert E. Lamond Alberta, Canada	Vice President, Asset Development	Vice President, Asset Development of Rife	September 5, 2017
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary of Rife	February 1, 2008

As at March 2, 2022, the directors and senior officers of the Manager as a group beneficially owned, directly or indirectly, or exercised control or direction over 193,481 Common Shares. Rife owns 100% of the outstanding shares in the capital of the Manager. All of the shares of Rife are owned by the CN Pension Trust Funds.

Conflicts of Interest

There may be situations in which the interests of the Manager will conflict with those of the Shareholders. As part of the ordinary course of business of the Manager, the Manager may continue to acquire oil and natural gas properties on its own behalf and on behalf of persons other than Freehold. The Manager may manage and administer such properties, as well as enter into other types of energy-related management, advisory and investment activities. Thus, neither the Manager nor its management will carry on their full-time activities on behalf of Freehold and, when acting on its own behalf or on behalf of others, may at times act in contradiction to or in competition with the interests of the Shareholders. In addition, there are times when Freehold may participate or enter into transactions with Canpar and Rife.

In resolving such conflicts, decisions will be made by the Manager on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties all consistent with the duties of the Manager to each such group of persons. The Management Agreement contains provisions that require the Manager to make disclosure to the Board of Directors of the fact and substance of any particular conflict of interest and to use all reasonable efforts to resolve such conflicts of interest in a manner that will treat Freehold and the other interested party fairly taking into account all of the circumstances of Freehold and such interested party and to act honestly and in good faith in resolving such matters.

Although the Manager provides advisory and management services to Freehold, the Board of Directors supervises the management of the business and affairs of Freehold. The Board of Directors makes all decisions relating to: (i) the issuance of additional Common Shares; (ii) the acquisition and disposition of properties for a purchase price or proceeds in excess of $10 million; (iii) the approval of capital expenditure budgets; (iv) the establishment of credit facilities; and (v) the determination of the amount of dividends to Shareholders.

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations that are in competition to the interests of Freehold. No assurances can be given that opportunities identified by such board members will be provided to Freehold.

The Board of Directors has implemented a related party transaction policy that sets out a specific process for consideration and Board approval of potential acquisitions, dispositions, joint ventures, farm-in arrangements and transactions of a similar nature that are outside the ordinary course of business ("**Related Party Transactions**") and involve Freehold and Rife and/or Canpar. The policy provides for negotiation of the terms of any Related Party Transaction by representatives of Freehold who do not have a material interest in such transaction. In addition, the policy requires that any such Related Party Transaction must be approved by members of the Board of Directors who do not have a material interest in such transaction.

To clarify the access to acquisition opportunities that are sourced by the Manager or Rife, effective March 1, 2021, Rife, Freehold, the Manager and Canpar entered into the Acquisitions Opportunities Agreement to complement the existing provisions in the Management Agreement. Under the terms of the Acquisitions Opportunities Agreement, Rife ensures that Freehold receives priority to consider acquisition opportunities for royalty interests in oil and gas properties and in alternative minerals (non-oil and gas) properties except in the case of alternative minerals opportunities that are related to an existing property of Rife or Canpar. The Acquisitions Opportunities Agreement also sets out a framework that allows each of Freehold and Rife (or Canpar) an opportunity to elect to participate in acquisition opportunities for royalty interests in alternative minerals (non-oil and gas) with the percentage of each entities' participation dependent on whether the property relates an existing property of Rife, Canpar or Freehold.

Legal Proceedings and Regulatory Actions

Other than as described below, to the knowledge of management of Freehold as at the date hereof, there are no legal proceedings that Freehold is a party to, or that any of Freehold's property is the subject of, that is material to Freehold, 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 Freehold if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of Freehold'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.

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

Freehold's corporate income tax filings for 2015, 2018, and 2019 were reassessed by the CRA in 2020. Pursuant to the Reassessments, deductions of $92.6 million of non-capital losses by Freehold were denied, resulting in reassessed taxes, interest, and penalties totaling $29.3 million in addition to a denial of $129.9 million of carried forward non-capital losses.

Freehold has filed its objection of the Reassessments which required deposits totaling $14.7 million that have been provided to the CRA. Freehold has received legal advice that it should be entitled to deduct the non-capital losses and as such, management remains of the opinion that all tax filings to date were filed correctly and that it expects to be successful in its objection of these Reassessments and therefore the payment of these deposits held by the CRA should be refunded, plus interest, and the denied non-capital losses should be reinstated.

Interest of Management and Others in Material Transactions

Other than as disclosed below or herein, there were no material interests, direct or indirect, of any directors or executive officers of the Manager, directors or executive officers of Freehold, 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 Freehold.

As described under "*General Development of Business – Year Ended December 31, 2020*", as part of the December 2020 Financing, CN Pension Trust Funds through Rife purchased 2,791,667 2020 Subscription Receipts at a price of $4.80 per 2020 Subscription Receipt for gross proceeds of approximately $13.4 million on a non-brokered private placement basis. CN Pension Trust Funds also participated in the September 2021 Offering by purchasing 939,200 2021 Subscription Receipts at a price of $9.05 per 2021 Subscription Receipt for gross proceeds of approximately $8.5 million. See "*General Development of Business – Year Ended December 31, 2021*".

The Manager and Rife are wholly-owned subsidiaries of the CN Pension Trust Funds, which held, directly or indirectly, 27,227,464 Common Shares as at March 2, 2022, representing approximately 18.08% of the outstanding Common Shares. The Manager receives certain compensation and reimbursement for a portion of general and administrative expenses for providing management services to Freehold, FHT and the Partnership as described under "The Manager". All transactions during 2021 were in the normal course of operations and were measured at the exchange amount, which is the amount of consideration established and agreed to by Freehold and the Manager.

Transfer Agent and Registrar

Computershare Trust Company of Canada 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 only material contracts we have entered into within the most recently completed financial year, or before the most recently completed financial year but which are still in effect, are the following:

- the Governance Agreement dated December 31, 2010, as described under the heading "*Directors and Officers – Governance Agreement*";
- the Management Agreement dated November 9, 2015, as described under the heading "*The Manager – Management Agreement*"; and
- the agreement governing our credit facilities between Freehold, FHT and the Partnership and their lenders dated May 9, 2018, amended May 7, 2019 and September 24, 2021 and as described under "*Borrowings*".

Interest 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, we have made under NI 51-102 during, or relating to, our 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, our independent auditors and Trimble and Ryder Scott, our independent engineering evaluators.

Interest of Experts

KPMG LLP are our auditors and have confirmed they are independent with respect to Freehold within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

As at the date hereof, the designated professionals (as defined in NI 51-102) of Trimble and Ryder Scott, as a group, beneficially owned, directly or indirectly, less than 1% of our outstanding securities including the securities of our associate or affiliate entities.

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 the Manager or Freehold or any of our associate or affiliate entities.

Additional Financial and Other Information

Additional information about Freehold may be found on SEDAR at www.sedar.com. Information about remuneration and indebtedness of directors and officers of Freehold and the Manager, principal holders of the Common Shares and securities authorized for issuance under our security-based compensation arrangements, will be contained in our Management Information Circular to be dated on or about March 23, 2022, which relates to our Annual Meeting of Shareholders to be held on May 10, 2022. Additional financial information is provided in Freehold's consolidated financial statements for the year ended December 31, 2021 and the accompanying management's discussion and analysis.

For copies of our consolidated financial statements and accompanying management's discussion and analysis and the Management Information Circular and additional copies of the AIF (in certain circumstances reasonable fees may apply) please contact:

Corporate Secretary
Freehold Royalties Ltd.
Suite 1000, 517 – 10th Avenue SW
Calgary, Alberta T2P 0A8
Telephone: 403-221-0802
Toll Free: 1-888-257-1873
Fax: 403-221-0888

Appendices

Appendix A

Form 51-101F2
Report on Reserves Data by Independent Qualified Reserves Evaluators

To the Board of Directors of Freehold Royalties Ltd. (the "**Corporation**") and Rife Resources Management Ltd., as manager of the Corporation:

1. We have evaluated the Corporation's reserves data as at December 31, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Corporation'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%, included in the reserves data of the Corporation evaluated for the year ended December 31, 2021, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator	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) Including Inactive Costs and Capital ($000s)			
			Audited	Evaluated	Reviewed	Total
Trimble Engineering Associates Ltd.	December 31, 2021	Canada	$0	$746,041	$0	$746,041
RSC Group, Inc.	December 31, 2021	United States	$0	$636,696	$0	$636,696
TOTALS			$0	$1,382,737	$0	$1,382,737

6. In our opinion, the reserves data respectively 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 judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Trimble Engineering Associates Ltd.

(signed) "*Stephen C. Trimble*"
Stephen C. Trimble, P.Eng.
President & Managing Director

Calgary, Alberta, Canada

March 2, 2022

RSC Group, Inc.

(signed) "*David Haugen*"
David Haugen, P. Eng.
Managing Senior Vice President

Calgary, Alberta, Canada

March 2, 2022

APPENDIX B

Form 51-101F3
Report of Management and Directors on Oil and Gas Disclosure

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

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators is presented in Appendix A of this Annual Information Form.

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

a. reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;

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

c. reviewed the reserves data with management and the independent qualified reserves evaluators.

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

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

b. the filing of Form 51-101F2, which is the report of the independent qualified reserves evaluators 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) "*David M. Spyker*"
David M. Spyker
President, Chief Executive Officer and Director

(signed) "*David W. Hendry*"
David W. Hendry
Vice President, Finance and Chief Financial Officer

(signed) "*Aidan M. Walsh*"
Aidan M. Walsh
Director and Chair, Reserves Committee

(signed) "*J. Douglas Kay*"
J. Douglas Kay
Director and Member, Reserves Committee

DATED as of this 2nd day of March, 2022.

APPENDIX C

Audit Committee Mandate

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Freehold Royalties Ltd. ("**Freehold**") to which the Board has delegated certain responsibilities for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

1. to assist directors in meeting their responsibilities, especially for accountability, in respect of the preparation and disclosure of the financial statements of Freehold and related matters;
2. to provide better communication between directors and the external auditors;
3. to enhance the external auditors' independence;
4. to increase the transparency, credibility and objectivity of financial reporting; and
5. to strengthen the role of the independent directors by facilitating in-depth discussions between directors on the Committee, management and the external auditors.

Membership of Committee

1. The Committee will be comprised of at least three directors, all of whom are independent (as such term is used in National Instrument 52-110 – Audit Committees ("**NI 52-110**")).
2. The Board will have the power to appoint the Committee Chair.
3. All of the members of the Committee will be financially literate. The Board has adopted the definition for financial literacy used in NI 52-110.

Meetings

1. At all meetings of the Committee, every question will be decided by a majority of the votes cast. In case of an equality of votes, the Committee Chair is not entitled to a second or deciding vote.
2. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board.
3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer ("**CFO**") will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Committee Chair.
4. The Committee will forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.
5. The Committee will 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.
6. The Committee will hold an in-camera session, without members of management or management directors, at each meeting. The Committee may invite other directors, members of management, and advisors to attend all or part of any in-camera session, as it deems advisable.

Mandate and Responsibilities

The mandate and responsibilities of the Committee will be as set forth below:

1. Oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting;

2. Satisfy itself on behalf of the Board with respect to Freehold's internal control systems, which include:
   (a) identifying, monitoring and mitigating business risks; and
   (b) ensuring compliance with legal, ethical and regulatory requirements;

3. Review the annual and quarterly financial statements of Freehold prior to their submission to the Board for approval. The process should include but not be limited to:
   (a) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
   (b) reviewing significant accruals, reserves or other estimates such as impairment testing;
   (c) reviewing accounting treatment of unusual or non-recurring transactions;
   (d) ascertaining compliance with covenants under loan agreements;
   (e) reviewing adequacy of reclamation provisions;
   (f) reviewing disclosure requirements for commitments and contingencies;
   (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   (h) reviewing unresolved differences between management and the external auditors; and
   (i) obtaining explanations of significant variances with comparative reporting periods;

4. Review the financial statements, prospectuses, management discussion and analysis, annual information forms, earnings news releases, and all public disclosure containing audited or unaudited financial information before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Freehold's disclosure of all other financial information and will periodically assess the accuracy of those procedures;

5. Recommend to the Board the annual appointment of external auditors, and in so doing:
   (a) annually review the performance and independence of the external auditors;
   (b) review the terms of engagement of the auditor, including the compensation of the auditors;
   (c) confirm that the auditors will report directly to the Committee;
   (d) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
   (e) review and approve any non-audit services to be provided by the auditors' firm and consider the impact on the independence of the auditors;

6. Review with external auditors, and the internal auditor if one is appointed by Freehold, their assessment of the internal controls of Freehold, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their audit plan and, upon completion of the audit, their reports upon the financial statements of Freehold and its subsidiaries;

7. Pre-approve all non-audit services to be provided to Freehold or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time;

8. Review, on an annual basis, the risk management policies and procedures of Freehold, including hedging, litigation and insurance;

9. Review and approve management's hiring policies regarding current and former partners and employees of the present and former external auditor;

10. Establish procedures for:
   (a) the receipt, retention and treatment of complaints received by Freehold regarding accounting, internal accounting controls or auditing matters; and
   (b) the confidential, anonymous submission by employees of Rife Resources Management Ltd. (the "**Manager**") of concerns regarding questionable accounting or auditing matters;

11. To review and report to the Board on the procedures in place for reporting and certification under the *Extractive Sector Transparency Measures Act* (Canada) ("**ESTMA**");

12. The Committee will have the authority to investigate any financial activity of Freehold. All employees of the Manager are to cooperate as requested by the Committee; and

13. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of Freehold without any further approval of the Board.

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