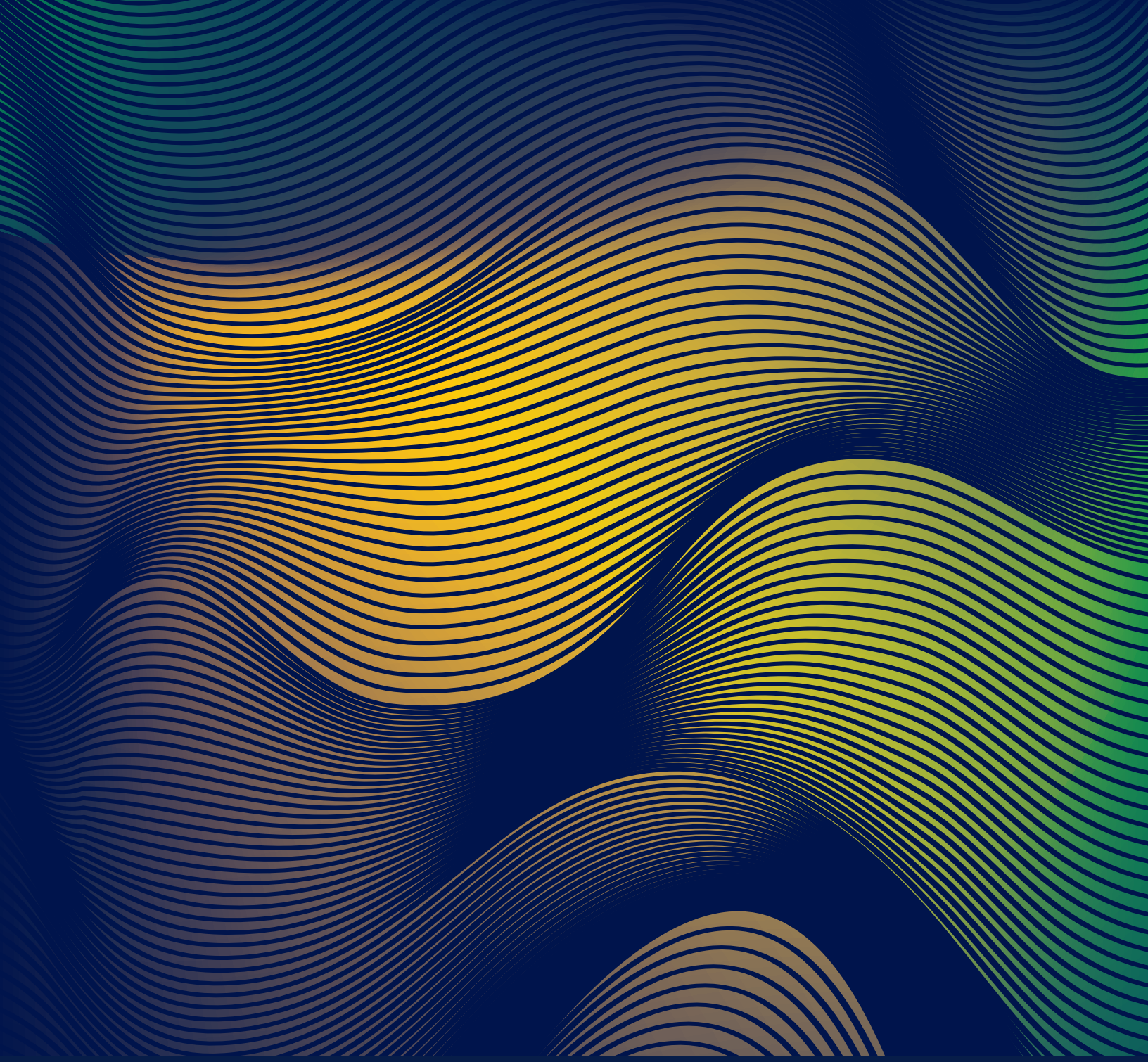


FREEHOLD
ROYALTIES

Annual Information Form (AIF)

TSX FRU | March 11, **2026**

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Advisories

Cautionary Statement Regarding Forward-Looking 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's acquisition strategy, including that it may acquire additional energy-related royalties that are primarily of a low-risk nature and that it targets individual properties or groups of properties with a focus on royalty interests and the anticipated results therefrom;
- the possibility that the Board of Directors may, in the future, vary the key criteria informing Freehold's acquisition strategy;
- Freehold's expectations that drilling activity on Royalty Lands will continue to provide new sources of crude oil and natural gas Royalty Income in future years, with wells and production partially offsetting declines;
- expected potential for drilling activities on undeveloped Royalty Lands;
- the expectation of certain activities to be undertaken by operators in areas in which we have a royalty or working interest;
- expected timing for development of undeveloped reserves;
- expectations that Freehold will continue to see the benefit of well capitalized and active operators pursuing high netback opportunities in Saskatchewan East;
- the expectation that all of the proved undeveloped reserves in the Ryder Scott Report will be developed in the next two years, and that all probable undeveloped reserves in the Ryder Scott Report will be drilled between 2026 and 2035, with 18% forecast to be drilled in 2026 and 2027, and the balance to be drilled between 2028 and 2035;
- the expectation that approximately 33% of probable undeveloped reserves from the GLJ Report will be drilled in the next two years, with the balance of probable undeveloped reserves from the GLJ Report to be drilled within ten years;
- the estimated future value of our crude oil and natural gas reserves;
- expectations that Freehold will not make any Development Cost (as defined herein) expenditures relating to the reserves associated with its working interest properties;
- the expectation that Freehold will have no future Development Costs associated with development of its reserves;
- estimated operating costs;
- estimated abandonment and reclamation costs of working interest properties;
- projections of market prices, costs and exchange and inflation rates;

- expectations with respect to income tax payable in Canada and the United States in 2026;
- expectations that future capital expenditures will maintain or improve production and the sources of financing for capital expenditures;
- Freehold's expectations with respect to defending its tax filing position with the CRA and anticipated results/outcome;
- expectations with respect to the timing of Freehold's Annual Meeting of Shareholders and documents relating thereto;
- the expectation that properties acquired will be operated by competent third parties;
- the anticipated acreage of unproved properties on which Freehold expects its rights to expire within the next year;
- the possibility that Freehold, in the future, may acquire or move into new industry related activities or new geographical areas;
- Freehold's belief that it should be classified as a PFIC (as defined herein) and that it will likely be a PFIC in subsequent years; and
- expectations regarding future climate change, emission reduction and emission cap regulations, liability management regulations and regulations regarding Indigenous consultation and the resulting effects on Freehold and the industry in general.

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 crude oil, natural gas liquids and natural gas;
- the impacts to the Corporation's business relating to (i) tariffs and other trade measures that have been or may be implemented or changed by the U.S. and Canadian governments, and (ii) the upcoming USMCA (as defined herein) review;
- the impacts of the ongoing conflicts in the Middle East region (including the U.S., Israel and Iran conflict), and Russia-Ukraine war and any associated sanctions as well as OPEC+ (as defined herein) curtailments on the global economy and commodity prices;
- geopolitical instability;
- political instability, including potential changes in the federal government in Canada;
- the impacts of inflation and supply chain shortages on the operations of our industry partners and royalty payors, as well as on demand and commodity prices;
- inflationary pressures;
- our ability to continue paying dividends;
- future capital expenditure levels;
- future production levels;
- future exchange rates;
- future tax rates;
- future legislation;
- the cost of developing and expanding our assets;
- our ability and the ability of our industry partners and royalty payors to obtain equipment in a timely manner to carry out development activities;
- our ability to market our product successfully to current and new customers;
- our expectation for the consumption of crude oil, natural gas liquids and natural gas;
- our expectation for industry drilling levels on our royalty lands;
- the impact of competition;
- that our quality counterparts provide a certainty of development into Freehold's royalty portfolio;
- our ability to obtain financing on acceptable terms;

- our ability to add production and reserves through our development and acquisitions activities.
- pipeline capacity constraints;
- our ability to obtain third party consents in a timely manner when reasonably required
- currency fluctuations;
- our and our counsel's interpretation of tax laws, regulations, royalties, or incentive programs relative to the interpretation and enforcement thereof by governmental authorities;
- changes in income tax laws or changes in tax laws, regulations, royalties, or incentive programs relating to the oil and gas industry;
- reliance on royalty payors to drill and produce on our lands and their ability to pay their obligations;
- uncertainties or imprecision associated with estimating crude oil and natural gas reserves;
- stock market volatility and our ability to access sufficient capital from internal and external sources;
- a significant or prolonged downturn in general economic conditions or industry activity;
- incorrect assessments of the value of acquisitions;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling, and processing problems;
- unanticipated litigation;
- environmental risks and liabilities inherent in crude oil and natural gas operations;
- influence of macroeconomic developments;
- business opportunities that become available to, or are pursued by Freehold; reduced access to debt and equity capital;
- title, permit or license disputes related to interests on any of the properties in which Freehold holds a royalty interest;
- excessive cost escalation as well as development, permitting, infrastructure, operating or technical difficulties on any of the properties in which Freehold holds a royalty interest;
- actual hydrocarbon content may differ from the reserves and resources contained in evaluation reports;
- rate and timing of production differences from resource estimates and other evaluation reports; 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 accuracy of assumptions and information used in Freehold's internal assessments of its Royalty Lands and the prospectivity thereof;
- the accuracy of publicly disclosed expectations for the development of underlying properties that are not yet in production;
- the impact of increasing competition;
- the impact of anti-competitive behavior of third parties;
- the general stability of the economic and political environment in which we have an interest in crude 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 Corporation to obtain qualified staff, equipment and services in a timely and cost-efficient manner;
- drilling results;

- royalty rates;
- 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 applicability and impacts to the Corporation's business of (i) tariffs and other trade measures that have been or may be implemented or changed by the U.S. and Canadian governments, and (ii) the upcoming USMCA review;
- 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 crude oil and natural gas reserves through acquisition, development and exploration;
- the performance and characteristics of the crude 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;
- our expectation for the consumption of crude oil and natural gas;
- the timing and amount of capital expenditures;
- future operating costs;
- future crude oil and natural gas prices;
- currency, exchange and interest rates;
- the interpretation and implementation of tax legislation;
- future tax rates;
- the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which we have an interest in crude oil and natural gas properties; and
- the ability of the operator of the properties in which we have an interest to successfully market its crude 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.

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 crude 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 Crude Oil and Natural Gas Reserves and Production Information

All crude oil and natural gas reserve information contained in this AIF has been prepared and presented in accordance with NI 51-101. The actual crude 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 crude oil and natural gas 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.

"**2024 U.S. Royalty Transaction**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year ended December 31, 2024*".

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

"**Assessments**" has the meaning ascribed thereto under the heading "*Legal Proceedings and Regulatory Actions*".

"**Audit Financial Expert**" means a person with experience as: (i) a chartered accountant; (ii) a certified public accountant; (iii) a former or current CFO of a public company or corporate controller with similar experience; (iv) a current or former partner of an audit firm; or (v) having similar demonstrably meaningful audit experience.

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

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

"**CNID**" means CN Investment Division, the manager of the CN Pension Trust Funds.

"**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.

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

"**Deferred and Restricted Share Unit Plan**" means the amended and restated deferred and restricted share unit plan for non-management directors of Freehold whereby fully vested Deferred Share Units and/or Restricted 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**" or "**DSUs**" means our deferred share units issued pursuant to the Deferred and Restricted Share Unit Plan.

"**Development Costs**" has the meaning ascribed thereto under "*Forecast Prices and Costs*".

"**Development Well**" means a well drilled inside the established limits of a crude 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**" has the meaning ascribed thereto under the heading "*Forecast Prices and Costs*".

"**Exploratory Well**" means a well that is not a Development Well, a Service Well or a Stratigraphic Test Well.

"**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 Continuing Employees**" means former employees of Rife whose employment was transferred to Freehold upon termination of the Management Agreement.

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

"**GLJ**" means GLJ Ltd., independent qualified reserves evaluators of Calgary, Alberta.

"**GLJ Report**" means the report dated January 29, 2026 prepared by GLJ, evaluating our Canadian crude oil, natural gas, and natural gas liquids reserves as at December 31, 2025.

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

"**Governance Agreement**" means the governance agreement between the Manager and Freehold dated as of December 31, 2010 and terminated effective December 31, 2025.

"**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.

"**Management Agreement**" means the fourth amended and restated agreement dated November 9, 2015 among the Manager, Rife, Freehold, FHT and the Partnership, which was terminated effective December 31, 2025, pursuant to which the Manager provided management services to Freehold, FHT and the Partnership.

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

"**Manager**" means Rife Management Ltd. (formerly 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.

"**NGL**" means natural gas liquids.

"**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*.

"**Nominee Agreement**" means the nominee agreement between the Freehold and CN Pension Trust Funds dated effective as of January 1, 2026.

"**Notice of Termination**" has the meaning ascribed under the heading "*General Development of the Business – Year ended December 31, 2025*".

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

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

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

"**Restricted Share Units**" or "**RSUs**" means our restricted share units issued pursuant to the Deferred and Restricted Share Unit Plan.

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

"**Rife Royalties**" means Rife Royalties Ltd. (formerly Canpar Holdings Ltd.), a wholly-owned subsidiary of the CN Pension Trust Funds.

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

"**Royalty Lands**" means the 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 11, 2026 prepared by Ryder Scott, evaluating our U.S. crude oil, natural gas and natural gas liquids reserves as at December 31, 2025.

"**SEDAR+**" means the System for Electronic Data Analysis and Retrieval+, as maintained by the Canadian Securities Administrators.

"**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, saltwater disposal, water supply for injection, observation or injection for combustion.

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

"**Stratigraphic Test Well**" means any well or hole, except a seismograph shot hole, drilled for the purpose of gathering information with no intent to produce crude oil or gas from such well.

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

"**Termination Date**" has the meaning ascribed under the heading "*General Development of the Business – Year ended December 31, 2025*".

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

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

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

"**USMCA**" means the United States-Mexico-Canada Agreement or, as referred to in Canada, the Canada-United States-Mexico Agreement.

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 North American energy royalty corporation based in Calgary, Alberta.

On January 1, 2011, Freehold, directly or indirectly, acquired all of the assets and assumed all of the liabilities of Freehold Royalty Trust pursuant to a plan of arrangement. From 1996 to 2010, the business of the Corporation was carried on as an income trust by Freehold Royalty Trust and its subsidiaries.

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

The royalties, working interest properties and other interests in energy-related assets are held by Freehold and its subsidiaries: 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.

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.

1872348 is a corporation formed under the laws of Alberta. 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. 1872348 acts as FHT's trustee.

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.

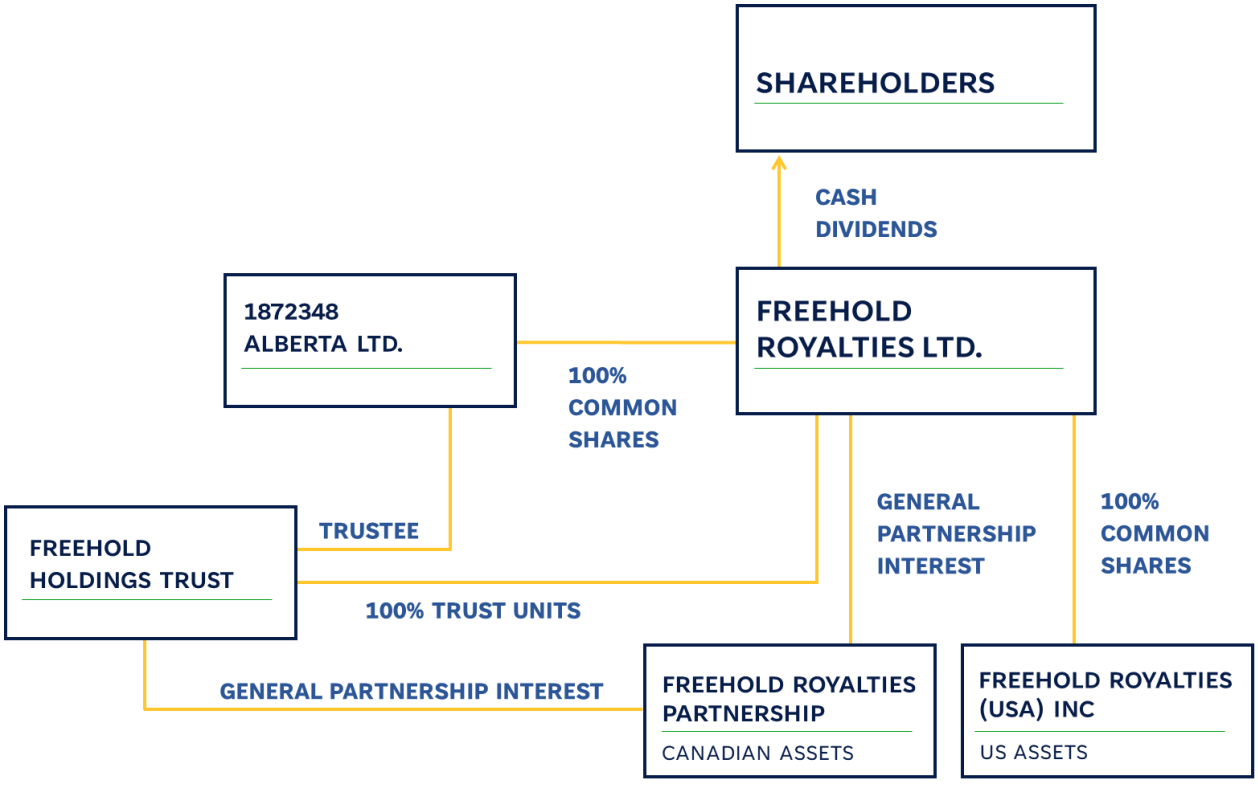
Structure of the Corporation

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

Below is a summary of Freehold's business development since January 1, 2023.

Year Ended December 31, 2023

On December 10, 2023, Freehold entered into definitive agreements with two private sellers to acquire high quality Permian mineral title and royalty assets located in the Midland basin in Texas and the Delaware basin in New Mexico and Texas for approximately US$86 million ($116 million), net of customary closing adjustments. These assets included 123,000 gross drilling acres concentrated in the core of the Permian Basin (approximately 76% in the Midland basin and 24% in the Delaware basin). Freehold closed these acquisitions on January 4 and January 16, 2024.

Year Ended December 31, 2024

On December 13, 2024, Freehold closed a transaction (the "**2024 U.S. Royalty Transaction**") whereby it purchased certain mineral title and royalty interest assets in the Midland basin in Texas for an aggregate purchase price of approximately US$185 million ($261 million), net of customary closing adjustments, from a private seller. On the same date, Freehold completed a bought deal equity offering in which it issued approximately 13.3 million Common Shares at a price of $13.00 per share for gross proceeds of approximately $172.5 million. The net proceeds from the bought deal equity offering were used to partially fund the purchase price for the 2024 U.S. Royalty Transaction, with the remainder of the purchase price for such acquisition funded from Freehold's existing credit facilities.

The 2024 U.S. Royalty Transaction added approximately 244,000 gross drilling acres to Freehold's portfolio and added approximately 1,500 boe/d of crude oil-weighted production in 2025. During the year ended December 31, 2024, Freehold completed approximately $14 million of acquisitions in early development stage mineral title and royalty assets across the Permian Basin and $14 million for gross overriding royalties in Canada.

Year Ended December 31, 2025

On April 30, 2025, it was mutually agreed by Freehold and the Manager to terminate the Management Agreement. Accordingly, Freehold provided notice to the Manager that it was terminating the Management Agreement (the "**Notice of Termination**") effective December 31, 2025 (the "**Termination Date**"). The Board of Directors made this decision with the support of CNID, as the manager of CN Pension Trust Funds who indirectly owned the Manager. Freehold was not required to pay the Manager a termination fee or any future management fees for periods after the Notice of Termination. Following the delivery of the Notice of Termination, although Freehold continued to be managed by the Manager until the Termination Date, the Freehold executive team and employees were fully dedicated to the business of Freehold. Freehold was responsible for reimbursement of certain general and administrative costs until the Termination Date. Freehold and the Manager worked collaboratively, resulting in an orderly and stable transition of systems, software, workflows, files and office space prior to the Termination Date. On December 31, 2025, the Management Agreement was terminated and on January 1, 2026 the employment of all Freehold Continuing Employees was transferred to Freehold.

In accordance with its terms, the Governance Agreement was terminated concurrently with the termination of the Management Agreement on December 31, 2025. As a result, Freehold and CN Pension Trust Funds entered into the Nominee Agreement, which provides CNID the right to nominate for election one individual as a director of Freehold. If the individual nominated by CNID fails to get elected, the Nominee Agreement provides CNID with

the right to appoint one observer at all meetings of directors of Freehold. The Nominee Agreement will terminate when and if CN Pension Trust Funds and any affiliated entities, hold less than 10% of the issued and outstanding Common Shares.

During the year ended December 31, 2025, Freehold completed approximately $32 million of acquisitions in early development stage mineral title and royalty assets across the Permian Basin and $6 million of acquisitions of gross overriding royalties in Canada.

Business of the Corporation

The following provides a description of Freehold's business and assets as at December 31, 2025 (unless otherwise indicated).

Overview

Freehold is a dividend paying, energy royalty corporation based in Calgary, Alberta. Freehold manages one of the largest non-government portfolios of crude 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 6.0 million gross acres in Canada and Freehold has exposure to approximately 1.2 million gross drilling 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 5.0 million acres. Freehold's U.S. acreage is comprised of 80% mineral title lands.

Freehold has royalty interests in more than 21,000 producing wells and almost 500 pooled interests or units spanning five provinces and eight states and receives Royalty Income from approximately 380 industry operators throughout North America. Freehold's revenues also include bonus consideration, lease rental and potash royalties that supplement its revenue portfolio.

Royalties offer the benefit of sharing in production, without exposure to the capital, operating and environmental costs, including reclamation liabilities, associated with production of crude oil, natural gas, and potash. As a royalty interest owner, Freehold does not pay any of the capital costs to drill, complete and equip 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 third parties who conduct activities on the Royalty Lands. Freehold receives Royalty Income from gross production revenue (revenue before any other royalty expenses and operating costs are deducted). Freehold's royalty positions are generally considered "interests in land" which is a benefit in that these royalties generally survive through an insolvency event of the operator.

Acquisition Strategy

Freehold may, directly or indirectly through its subsidiaries and partnerships, acquire additional energy-related royalties that are primarily of a low-risk nature. Acquired properties are operated by 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 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 management of Freehold on presenting acquisitions for approval by the Board of Directors. The Board of Directors may vary these criteria for any particular acquisition based on management'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 North American energy sector. These companies are required to operate in accordance with applicable environmental regulatory frameworks in the jurisdictions in which they operate.

Reserves Data

Our statement of reserves data and other crude oil and natural gas information is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2025.

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, GLJ and Ryder Scott. Both the GLJ Report and the Ryder Scott Report have an effective date of December 31, 2025. The GLJ Report has a preparation date of January 29, 2026 and the Ryder Scott Report has a preparation date of February 11, 2026.

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. Freehold's sulphur reserves are immaterial to the Corporation. As a result, GLJ was not requested to evaluate its sulphur reserves and they have not been presented herein. The GLJ 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 GLJ 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, 2025 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. GLJ 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 CRUDE OIL AND NATURAL GAS RESERVES AS OF DECEMBER 31, 2025 FORECAST PRICES AND COSTS[1,2]

CANADA

	Light and Medium Crude Oil		Tight Oil		Heavy Crude Oil	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)
Proved						
Developed producing	-	4,052	-	649	-	2,200
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,599	-	69	-	262
Total proved	-	5,651	-	718	-	2,462
Probable	-	2,767	-	225	-	1,183
Total proved plus probable	**-**	**8,418**	**-**	**943**	**-**	**3,645**

	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	-	40,313	-	256	-	1,864
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,896	-	-	-	855
Total proved	-	42,209	-	256	-	2,719
Probable	-	8,197	-	32	-	1,083
Total proved plus probable	**-**	**50,406**	**-**	**288**	**-**	**3,802**

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
Proved				
Developed producing	-	1,647	-	15,621
Developed non-producing	-	-	-	-
Undeveloped	-	89	-	2,477
Total proved	-	1,736	-	18,098
Probable	-	443	-	6,169
Total proved plus probable	**-**	**2,179**	**-**	**24,267**

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	-	6,588	-	19,726	-	2,969
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	554	-	1,456	-	278
Total proved	-	7,142	-	21,182	-	3,247
Probable	-	12,144	-	37,966	-	6,155
Total proved plus probable	**-**	**19,286**	**-**	**59,147**	**-**	**9,402**

	Total Oil Equivalent	
Reserves Category	Gross (Mboe)	Net (Mboe)
Proved		
Developed producing	-	12,844
Developed non-producing	-	-
Undeveloped	-	1,075
Total proved	-	13,919
Probable	-	24,626
Total proved plus probable	**-**	**38,545**

TOTAL

	Light and Medium Crude Oil		Tight Oil		Heavy Crude Oil	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)
Proved						
Developed producing	-	4,052	-	7,237	-	2,200
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,599	-	623	-	262
Total proved	-	5,651	-	7,860	+	2,462
Probable	-	2,767	-	12,368	-	1,183
Total proved plus probable	**-**	**8,418**	**-**	**20,228**	**-**	**3,645**

	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	-	40,313	-	256	-	21,590
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	1,896	-	-	-	2,310
Total proved	-	42,209	-	256	-	23,901
Probable	-	8,197	-	32	-	39,049
Total proved plus probable	**-**	**50,406**	**-**	**288**	**-**	**62,949**

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
Proved				
Developed producing	-	4,616	-	28,465
Developed non-producing	-	-	-	-
Undeveloped	-	367	-	3,552
Total proved	-	4,983	-	32,017
Probable	-	6,598	-	30,795
Total proved plus probable	**-**	**11,581**	**-**	**62,812**

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, 2025 FORECAST PRICES AND COSTS[1,2,3]

CANADA	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	863,940	667,171	545,186	462,589	403,174
Developed non-producing	-	-	-	-	-
Undeveloped	198,726	147,292	115,421	93,880	78,456
Total proved	1,062,666	814,463	660,607	556,469	481,630
Probable	507,216	294,969	193,706	137,465	103,030
Total proved plus probable	**1,569,882**	**1,109,432**	**854,313**	**693,934**	**584,660**

CANADA	After Income Taxes[4], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	746,228	571,710	465,044	393,482	342,321
Developed non-producing	-	-	-	-	-
Undeveloped	154,592	113,820	88,922	72,204	60,269
Total proved	900,820	685,530	553,966	465,686	402,590
Probable	393,220	227,505	149,088	105,685	79,149
Total proved plus probable	**1,294,040**	**913,035**	**703,054**	**571,371**	**481,739**

UNITED STATES	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	820,056	503,918	370,470	298,522	253,386
Developed non-producing	-	-	-	-	-
Undeveloped	61,495	44,926	37,072	32,384	29,172
Total proved	881,550	548,845	407,543	330,906	282,558
Probable	1,638,794	880,686	573,812	412,634	314,769
Total proved plus probable	**2,520,344**	**1,429,530**	**981,354**	**743,540**	**597,327**

UNITED STATES	After Income Taxes[4], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	778,974	486,774	361,086	292,363	248,832
Developed non-producing	-	-	-	-	-
Undeveloped	47,749	37,015	31,882	28,719	26,453
Total proved	826,724	523,788	392,968	321,082	275,284
Probable	1,280,311	681,112	438,781	311,753	234,874
Total proved plus probable	**2,107,035**	**1,204,900**	**831,749**	**632,835**	**510,159**

TOTAL	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	1,683,996	1,171,089	915,656	761,111	656,560
Developed non-producing	-	-	-	-	-
Undeveloped	260,221	192,218	152,493	126,264	107,628
Total proved	1,944,216	1,363,308	1,068,150	887,375	764,188
Probable	2,146,010	1,175,655	767,518	550,099	417,799
Total proved plus probable	**4,090,226**	**2,538,962**	**1,835,667**	**1,437,474**	**1,181,987**

TOTAL	After Income Taxes[4], Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	1,525,202	1,058,484	826,130	685,845	591,153
Developed non-producing	-	-	-	-	-
Undeveloped	202,341	150,835	120,804	100,923	86,722
Total proved	1,727,544	1,209,318	946,934	786,768	677,874
Probable	1,673,531	908,617	587,869	417,438	314,023
Total proved plus probable	**3,401,075**	**2,117,935**	**1,534,803**	**1,204,206**	**991,898**

1. Columns may not add due to rounding.
2. Estimates of future net revenue reflect a deduction for estimated operating costs.
3. For the purposes of the GLJ Report on Freehold's Canadian working interest assets, estimates of future net revenue reflect a deduction for estimated 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. As Freehold only holds royalty interests in the United States and no working interests, for the purposes of the Ryder Scott Report on Freehold's United States assets, no deduction has been made for abandonment, decommissioning and reclamation costs as the Corporation has no liability for such costs on its royalty interest properties. No volumes have been attributed to Canadian working interest proved developed non-producing wells but there is associated inactive abandonment and reclamation costs, as such the future net revenue for such proved developed non-producing wells reflects negative revenues.
4. Based on the inclusion of $379,500,000 of tax pools for Canada and $660,900,000 of tax pools for the United States. See "*Other Oil and Gas Information – Tax Horizon*".

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2025 FORECAST PRICES AND COSTS[1]

	Proved Reserves		
($000s)	Canada	United States	Total
Royalty Income	1,072,629	978,442	2,051,071
Revenue from working interest properties	-	-	-
Royalty expense	-	-	-
Production and ad valorem taxes[2]	-	(64,855)	(64,855)
Operating costs[3]	-	(32,036)	(32,036)
Development costs	-	-	-
Abandonment and reclamation costs[4]	(9,964)	-	(9,964)
Future net revenue before income taxes	1,062,666	881,550	1,944,216
Future income taxes	(161,845)	(54,827)	(216,672)
Future net revenue after income taxes	**900,820**	**826,724**	**1,727,544**

	Proved Plus Probable Reserves		
($000s)	Canada	United States	Total
Royalty Income	1,579,845	2,800,912	4,380,757
Revenue from working interest properties	-	-	-
Royalty expense	-	-	-
Production and ad valorem taxes[2]	-	(193,558)	(193,558)
Operating costs[3]	-	(87,010)	(87,010)
Development costs	-	-	-
Abandonment and reclamation costs[4]	(9,964)	-	(9,964)
Future net revenue before income taxes	1,569,882	2,520,344	4,090,226
Future income taxes	(275,841)	(413,309)	(689,150)
Future net revenue after income taxes	**1,294,040**	**2,107,035**	**3,401,076**

1. Columns may not add due to rounding.
2. Represents both severance and ad valorem 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. The applicable ad valorem tax is specific to the law of the County in which operations take place. The ad valorem tax is levied as a percentage of market value of the hydrocarbon product.
3. 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.
4. For the purposes of the GLJ Report on Freehold's Canadian working interest assets, estimates of future net revenue reflect a deduction for estimated 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. As Freehold only holds royalty interests in the United States and no working interests, for the purposes of the Ryder Scott Report on Freehold's United States assets, no deduction has been made for abandonment, decommissioning and reclamation costs as the Corporation has no liability for such costs on its royalty interest properties.

FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2025 FORECAST PRICES AND COSTS[1]

CANADA

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	$/boe	$/Mcfe
		($000s)		
Proved	Light and Medium Crude Oil (including solution gas and by-products)	353,198	48.68	8.11
	Tight Oil (including solution gas and other by-products)	45,858	56.78	9.46
	Heavy Crude Oil (including solution gas and other by-products)	135,483	50.84	8.47
	Conventional Natural Gas (including by-products)	118,434	17.29	2.88
	Coal Bed Methane (including by-products)	527	12.34	2.06
	Shale Gas (including by-products)	7,107	14.87	2.48
	Total Proved	**660,607**	**36.50**	**6.08**
Proved plus probable	Light and Medium Crude Oil (including solution gas and by-products)	471,260	44.16	7.36
	Tight Oil (including solution gas and other by-products)	55,511	52.36	8.73
	Heavy Crude Oil (including solution gas and other by-products)	186,548	47.55	7.92
	Conventional Natural Gas (including by-products)	131,515	16.66	2.78
	Coal Bed Methane (including by-products)	566	11.81	1.97
	Shale Gas (including by-products)	8,913	13.37	2.23
	Total Proved Plus Probable	**854,313**	**35.20**	**5.87**

UNITED STATES

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	$/boe	$/Mcfe
		($000s)		
Proved	Tight Oil (including solution gas and other by-products)	380,855	30.25	5.04
	Shale Gas (including by-products)	26,688	20.10	3.35
	Total Proved	**407,543**	**29.28**	**4.88**
Proved plus probable	Tight Oil (including solution gas and other by-products)	939,845	26.12	4.35
	Shale Gas (including by-products)	41,510	16.14	2.69
	Total Proved Plus Probable	**981,354**	**25.46**	**4.24**

TOTAL

Reserves Category	Well Type	Future Net Revenue Before Income Taxes Discounted at 10% per year	$/boe	$/Mcfe
		($000s)		
Proved	Light and Medium Crude Oil (including solution gas and by-products)	353,198	48.68	8.11
	Tight Oil (including solution gas and other by-products)	426,713	31.85	5.31
	Heavy Crude Oil (including solution gas and other by-products)	135,483	50.84	8.47
	Conventional Natural Gas (including by-products)	118,434	17.29	2.88
	Coal Bed Methane (including by-products)	527	12.34	2.06
	Shale Gas (including by-products)	33,795	18.72	3.12
	Total Proved	**1,068,150**	**33.36**	**5.56**
Proved plus probable	Light and Medium Crude Oil (including solution gas and by-products)	471,260	44.16	7.36
	Tight Oil (including solution gas and other by-products)	995,356	26.88	4.48
	Heavy Crude Oil (including solution gas and other by-products)	186,548	47.55	7.93
	Conventional Natural Gas (including by-products)	131,515	16.66	2.78
	Coal Bed Methane (including by-products)	566	11.81	1.97
	Shale Gas (including by-products)	50,423	15.58	2.60
	Total Proved Plus Probable	**1,835,667**	**29.23**	**4.87**

1. Columns may not add due to rounding.

Definitions and Other Notes

The crude oil, natural gas and natural gas liquids reserves estimates presented in the GLJ 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 crude oil and natural gas and related substances excluding sulphur 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 ("**Proved**" or "**proved**") 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 ("**Probable**" or "**probable**") 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. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates as at December 31, 2025 utilized in the GLJ Report and Ryder Scott Report were based on the average of the forecasts prepared by GLJ Ltd., McDaniel & Associates Ltd. and Sproule ERCE (formerly Sproule Associates Limited) effective as at January 1, 2026, which are as follows:

FORECAST PRICES USED IN ESTIMATES AS OF DECEMBER 31, 2025

	Crude 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	Access Western Blend 22° API $Cdn/bbl	Western Canadian Select 20.9° API $Cdn/bbl	AECO 30 Day Spot $Cdn/MMBtu	Henry Hub $US/MMbtu	Propane $Cdn/bbl	Butane $Cdn/bbl	Pentane $Cdn/bbl
2026	59.92	77.54	60.09	63.82	65.12	3.00	3.74	25.10	36.95	80.01
2027	65.10	83.60	64.94	69.02	70.43	3.30	3.78	27.28	39.79	86.19
2028	70.28	90.18	71.16	75.36	76.90	3.49	3.85	29.67	42.87	92.83
2029	71.93	92.32	72.84	77.14	78.71	3.58	3.93	30.37	43.89	95.05
2030	73.37	94.17	74.30	78.68	80.29	3.65	4.01	30.98	44.77	96.94
2037	74.84	96.06	75.80	80.26	81.90	3.72	4.09	31.60	45.67	98.89
2032	76.34	97.98	77.32	81.86	83.53	3.80	4.17	32.23	46.58	100.87
2033	77.87	99.93	78.87	83.50	85.20	3.88	4.26	32.87	47.51	102.88
2034	79.42	101.93	80.46	85.17	86.91	3.95	4.34	33.53	48.46	104.94
2035	81.01	103.97	82.07	86.87	88.65	4.03	4.43	34.20	49.43	107.04
	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
Year	Propane $US/ bbl	Butane[1] $US/ bbl	Condensate $US/ bbl	%/ Year	$US/ $Cdn
2026	28.99	32.95	52.13	-	0.73
2027	29.30	35.81	56.64	2.0	0.74
2028	31.62	38.65	61.14	2.0	0.74
2029	32.37	39.56	62.58	2.0	0.74
2030	33.02	40.35	63.83	2.0	0.74
2031	33.68	41.16	65.11	2.0	0.74
2032	34.35	41.99	66.42	2.0	0.74
2033	35.04	42.83	67.74	2.0	0.74
2034	35.74	43.68	69.10	2.0	0.74
2035	36.46	44.56	70.48	2.0	0.74
Thereafter, per year:					
	+2.0%	+2.0%	+2.0%	2.0	0.74

1. Butane prices 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, 2025:

FREEHOLD WEIGHTED AVERAGE PRICES YEAR ENDED DECEMBER 31, 2025

	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	76.49[1]	-	1.42[2]	-	45.18	44.17
United States						
Freehold weighted average price	-	90.77	-	2.58	27.00	59.39

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**" are costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude 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.

"**Exploration Costs**" are costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain crude 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.

All of Freehold's reserves as estimated in the GLJ Report and all of Freehold's reserves as estimated in 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 GLJ 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 GLJ and Ryder Scott were accepted by GLJ 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. In addition, Freehold has only presented a gross reserves reconciliation for conventional natural gas and natural gas liquids as those are the only product types in which Freehold holds a working interest.

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

CANADA	Conventional Natural Gas			Natural Gas Liquids			Total Oil Equivalent		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2024[2]	417	65	482	10	-	10	80	10	90
Production	(64)	0	(64)	(2)	-	(2)	(13)	-	(13)
Technical revisions[3]	(353)	(65)	(418)	(8)	-	(8)	(67)	(10)	(77)
Extensions and improved recovery	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2025	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

1. Columns may not add due to rounding.
2. Based on a report dated January 30, 2025 prepared by Trimble, evaluating our Canadian crude oil, natural gas, and natural gas liquids reserves as at December 31, 2024.
3. Freehold's operated working interest wells were shut in during 2025, remaining minor non-operated working interest wells have no reserves assigned.

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[2]	Light and Medium Crude Oil			Tight Oil			Heavy Crude 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, 2024[4]	5,698	2,904	8,602	838	310	1,148	2,836	889	3,725
Production	(842)	-	(842)	(135)	-	(135)	(566)	-	(566)
Technical revisions	855	(72)	783	12	(86)	(74)	137	1	138
Extensions and improved recovery	18	6	24	4	2	6	138	314	452
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	(78)	(71)	(148)	(1)	(0)	(1)	(83)	(21)	(104)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2025	**5,651**	**2,767**	**8,418**	**718**	**225**	**943**	**2,462**	**1,183**	**3,645**

CANADA[2]	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, 2024[4]	50,633	10,188	60,821	948	101	1,049	2,635	825	3,459
Production	(8,022)	-	(8,022)	(51)	-	(51)	(372)	-	(372)
Technical revisions	(1,835)	(2,472)	(4,307)	(640)	(67)	(707)	455	258	714
Extensions and improved recovery	1,575	644	2,219	-	-	-	1	1	2
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	(142)	(163)	(305)	(1)	(2)	(3)	(0)	(0)	(0)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2025	**42,209**	**8,197**	**50,406**	**256**	**32**	**288**	**2,719**	**1,083**	**3,802**

CANADA[2]	Natural Gas Liquids			Total Oil Equivalent		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2024[4]	1,685	420	2,105	20,093	6,375	26,468
Production	(303)	-	(303)	(3,253)	-	(3,253)
Technical revisions	291	6	297	958	(533)	425
Extensions and improved recovery	66	23	89	488	452	940
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	(3)	(6)	(9)	(188)	(125)	(313)
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2025	**1,736**	**443**	**2,179**	**18,098**	**6,169**	**24,267**

UNITED STATES[3]	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, 2024[4]	7,669	12,276	19,946	21,368	37,321	58,690	3,268	5,473	8,741
Production	(1,384)	(31)	(1,415)	(3,281)	(66)	(3,347)	(498)	(11)	(509)
Technical revisions	206	(3,376)	(3,170)	1,776	(8,000)	(6,224)	180	(1,495)	(1,314)
Extensions and improved recovery	78	19	97	115	27	143	19	4	23
Acquisitions	125	47	172	219	168	387	53	35	88
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	(6)	-	(6)	(15)	(4)	(19)	(3)	0	(3)
Infill drilling	453	3,208	3,661	998	8,520	9,518	229	2,147	2,376
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2025	**7,142**	**12,143**	**19,286**	**21,182**	**37,966**	**59,147**	**3,247**	**6,155**	**9,402**

UNITED STATES[3]	Total Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2024[4]	14,499	23,969	38,468
Production	(2,429)	(52)	(2,481)
Technical revisions	681	(6,202)	(5,521)
Extensions and improved recovery	116	28	144
Acquisitions	215	110	325
Dispositions	-	-	-
Economic factors	(11)	(2)	(12)
Infill drilling	848	6,775	7,622
Discoveries	-	-	-
December 31, 2025	**13,919**	**24,626**	**38,545**

TOTAL	Light and Medium Crude Oil			Tight Oil			Heavy Crude 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, 2024[4]	5,698	2,904	8,602	8,507	12,586	21,094	2,836	889	3,725
Production	(842)	-	(842)	(1,519)	(31)	(1,550)	(566)	-	(566)
Technical revisions	855	(72)	783	218	(3,462)	(3,244)	137	1	138
Extensions and improved recovery	18	6	24	82	21	103	138	314	452
Acquisitions	-	-	-	125	47	172	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	(78)	(71)	(148)	(7)	(0)	(7)	(83)	(21)	(104)
Infill drilling	-	-	-	453	3,208	3,661	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2025	**5,651**	**2,767**	**8,418**	**7,860**	**12,368**	**20,229**	**2,462**	**1,183**	**3,645**

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, 2024[4]	50,633	10,188	60,821	948	101	1,049	24,003	38,146	62,149
Production	(8,022)	-	(8,022)	(51)	-	(51)	(3,653)	(66)	(3,719)
Technical revisions	(1,835)	(2,472)	(4,307)	(640)	(67)	(707)	2,231	(7,743)	(5,510)
Extensions and improved recovery	1,575	644	2,219	-	-	-	117	28	145
Acquisitions	-	-	-	-	-	-	219	168	387
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	(142)	(163)	(305)	(1)	(2)	(3)	(15)	(4)	(20)
Infill drilling	-	-	-	-	-	-	998	8,520	9,518
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2025	**42,209**	**8,197**	**50,406**	**256**	**32**	**288**	**23,901**	**39,049**	**62,949**

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, 2024[4]	4,953	5,893	10,846	34,592	30,344	64,936
Production	(801)	(11)	(812)	(5,682)	(52)	(5,734)
Technical revisions	471	(1,489)	(1,017)	1,640	(6,735)	(5,096)
Extensions and improved recovery	84	27	112	604	480	1,084
Acquisitions	53	35	88	215	110	325
Dispositions	-	-	-	-	-	-
Economic factors	(6)	(5)	(12)	(199)	(127)	(326)
Infill drilling	229	2,147	2,376	848	6,775	7,622
Discoveries	-	-	-	-	-	-
December 31, 2025	**4,983**	**6,598**	**11,581**	**32,017**	**30,795**	**62,812**

1. Columns may not add due to rounding.
2. Material reserve changes for the Canadian assets relate to technical revisions, drilling extensions and improved recovery. Technical revisions relate to improved performance and probable reserves shifting to proved reserves as the assets mature. Drilling extensions relate to new wells drilled on Royalty Lands in 2025. Improved recovery relates to supplemental undeveloped locations added to the evaluation.
3. Material reserve changes for the U.S. assets relate to technical revisions, infill drilling and acquisitions. Technical revisions relate to production forecast revisions for proved developed producing wells, proved undeveloped conversions to proved developed producing, and net revenue revisions. Infill drilling relates to conversions into proved developed producing or drilled uncompleted wells from probable undeveloped locations as well as the addition of new probable undeveloped locations.
4. For Canada, based on a report dated January 30, 2025 prepared by Trimble, evaluating our Canadian crude oil, natural gas, and natural gas liquids reserves as at December 31, 2024. For the U.S., based on a report dated February 5, 2025 prepared by Ryder Scott, evaluating our U.S. crude oil, natural gas and natural gas liquids reserves as at December 31, 2024.

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards in the COGE Handbook. At December 31, 2025, the aggregate proved net undeveloped reserves assigned in the GLJ Report and Ryder Scott Report represented 11% of the aggregate proved net reserves assigned in such reports. At December 31, 2025, the aggregate probable net undeveloped reserves assigned in the GLJ Report and Ryder Scott Report represented 45% of the aggregate probable net reserves assigned in such reports. The following provides an explanation of how both GLJ 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 14% of the total proved net reserves assigned in the GLJ Report. The proved undeveloped reserves in the GLJ Report relate to locations that are within actively developed resource plays and adjacent to existing production. In the GLJ Report, approximately half of the proved undeveloped locations are forecast to be drilled in the next two years with the remainder forecast to be drilled in the following three 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.

In respect of Freehold's United States assets, proved net undeveloped reserves assigned represented 8% 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. All of the proved undeveloped reserves in the Ryder Scott Report are expected to be developed in the next two years.

Probable net undeveloped reserves assigned in the GLJ Report represented 24% of the total proved plus probable net reserves assigned to Freehold's Canadian assets. Similar to the proved undeveloped reserves in the GLJ

Report, the probable undeveloped reserves in the GLJ 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 resource plays where reserves are estimated from analog type curve analysis. In the GLJ Report, approximately 33% of the probable undeveloped locations are forecast to be drilled in the next two years. The balance of the probable undeveloped reserves in the GLJ 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.

Probable net undeveloped reserves assigned in the Ryder Scott Report represented 55% of the total proved plus probable net reserves assigned to Freehold's United States assets. Similarly to the probable undeveloped reserves booked in the GLJ 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 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 2026 and 2035, with 18% forecast to be drilled in 2026 and 2027. The balance of the probable undeveloped reserves in the Ryder Scott Report, which are forecast to be drilled between 2028 and 2035, 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, 2023, 2024, and 2025 based on forecast prices and costs:

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

Year[1]	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbls)
2023	142	355	176	359	1,060	170
2024	39	740	-	20	2,004	314
2025	-	344	138	55	834	186
Total Booked for Current Year	**1,599**	**623**	**262**	**1,896**	**2,311**	**367**

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

Year[1]	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbls)
2023	399	3,387	161	491	8,463	1,453
2024	96	2,011	-	61	314	318
2025	-	3,218	314	125	8,556	2,153
Total Booked for Current Year	**1,948**	**10,341**	**707**	**2,300**	**33,863**	**5,508**

1. The undeveloped crude oil, natural gas and natural gas liquids reserves associated with our Canadian properties were attributed in 2023 and 2024 by Trimble.

Significant Factors or Uncertainties

The reserve and recovery information contained in the GLJ 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 GLJ 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 GLJ and Ryder Scott, independent qualified reserves evaluators. GLJ 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 crude 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

The following provides a description of Freehold's business assets as at December 31, 2025 (unless otherwise indicated).

Freehold had crude 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 (approximately 6.0 million gross acres) and the states of Colorado, Louisiana, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas and Wyoming in the United States (approximately 1.2 million gross drilling acres).

Producing lands include Crown, freehold, unitized and non-unitized crude oil and natural gas, potash and other industrial resources production. The properties are operated by experienced operators. Our top ten active drillers through year-end 2025 were, in alphabetic order: APA Corporation, ConocoPhillips, Coterra Energy Inc. Diamondback Energy, Exxon Mobil Corporation, Ovintiv Inc., Oxyrock Operating LLC, Tamarack Valley Energy Ltd. Teine Energy Ltd. 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 crude oil and natural gas in-kind, which allows Freehold to take ownership of a percentage of the crude 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.

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

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 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 capital or operating costs, or environmental or reclamation liabilities; whereas a holder of a working interest is typically liable for its share of capital, operating and environmental costs as well as reclamation liabilities, 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 own 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 2025, this category of land provided approximately 45% of our overall (Canada and U.S.) royalty production.

In Canada, we have ownership interests in mineral titles generally ranging from 10% to 100% and recover the applicable royalty, generally ranging from 10% to 22.5% of all crude 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 revenue from the crude oil and/or natural gas produced for the period. In 2025, this category of land accounted for approximately 13% of our total royalty acreage in Canada.

Our Canadian mineral title lands encompass approximately 1,000,000 acres, of which 54% are leased and 46% are unleased. Our Canadian mineral title lands also include approximately 681,000 undeveloped acres, representing potential for future development.

In the United States, we have ownership interests in mineral titles and recover our applicable portion of the gross royalty, generally ranging from 12.5% to 25%, of all crude oil and gas produced from the leased lands, netted down by our interest in the drilling spacing unit. In 2025, this category of land accounted for approximately 78% of our total royalty acreage in the United States. The majority of our U.S. mineral title lands are developed and leased.

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 91,000 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 2025, this category of land accounted for approximately 1% of our total royalty acreage.

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 2025, this category of land provided approximately 51% of our overall (Canada and U.S.) royalty production.

In Canada, we hold GORRs in approximately 5.0 million acres, of which approximately 1.5 million acres are undeveloped. In 2025, this category of land accounted for approximately 82% of our total royalty acreage in Canada.

In the United States, we hold GORRs across approximately 270,000 gross drilling 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 2025, this category of land accounted for approximately 22% 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 crude oil and natural 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 2025, this category of royalty interests provided approximately 4% of our overall (Canada and U.S.) royalty production.

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, 2025, wells drilled, crude oil and natural gas production, and royalty interest for 2025 for our Royalty Lands:

Year ended December 31, 2025		Alberta West	Saskatchewan East	Permian (U.S.)	Eagle Ford (U.S.)	North Dakota & Other (U.S.)	Total
Average royalty interest [1,2]	(%)	1.8%	1.4%	1.0%	0.3%	0.4%	1.2%
Wells drilled	(gross)	152	139	724	74	21	1,110
Royalty interest revenue[3]	($000s)	6,283	2,628	4,381	2,469	533	16,294
	(boe/d)	75,180	68,495	94,945	57,258	7,834	303,712
Average net daily production							
	(% of total)	39%	16%	27%	15%	3%	100%
Crude Oil and NGL	(bbls/d)	2,682	2,374	3,456	1,966	253	10,731
	(% of total)	25%	22%	33%	18%	2%	100%
Natural gas	(Mcf/d)	21,600	1,536	5,550	3,018	1,678	33,382
	(% of total)	65%	5%	16%	9%	5%	100%
Net proved reserves	(Mboe)	13,870	4,228	4,898	7,887	1,134	32,017
Crude oil and NGL	(Mbbls)	6,636	3,933	3,952	5,910	527	20,956
	(% of total)	31%	18%	19%	28%	3%	100%
Natural gas	(MMcf)	43,409	1,775	5,675	11,865	3,642	66,366
	(% of total)	65%	3%	9%	18%	5%	100%
Net proved plus probable reserves	(Mboe)	19,211	5,056	14,795	21,365	2,386	62,812
Crude oil and NGL	(Mbbls)	10,464	4,721	11,595	16,350	742	43,872
	(% of total)	28%	12%	26%	37%	2%	100%
Natural gas	(MMcf)	52,484	2,012	19,201	30,086	9,860	113,643
	(% of total)	46%	2%	17%	26%	9%	100%
Future Net Revenue Before Income Taxes[1]							
Discounted at 10% per year	($000s)	591,525	262,788	398,337	540,458	42,560	1,835,667
	(% of total)	30%	13%	22%	29%	2%	100%

1. Based on proved plus probable reserves and forecast prices as assigned in the GLJ Report and the Ryder Scott Report.
2. Total average royalty interest calculated as weighted average of well count under each area.
3. 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, 2025**:**

Area	Developed Gross Acres	Undeveloped Gross Acres[1]	Total Gross Acres
Alberta West	3,129,640	1,572,251	4,701,891
Saskatchewan East	676,661	561,517	2,238,179
Eagle Ford (U.S.)	238,537	0	238,537
Permian (U.S.)	810,463	1,159	811,622
North Dakota & Other (U.S.)	220,345	0	220,345
Potash	13,069	7,669	20,739
Total	**5,088,715**	**2,142,596**	**7,231,311**

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

Alberta West

In 2025, 152 wells, representing 52% of our gross royalty drilling in Canada, occurred in the Alberta West area, which includes our Royalty Lands in British Columbia and Alberta. These wells primarily targeted established crude oil and natural gas liquids rich gas plays of the Cardium, Mannville and Spirit River group, as well as continued development and exploratory drilling in the Clearwater play. In this area, 100% of the wells are horizontal drills and approximately 80% of the wells targeted crude oil, while the other 20% of activity was concentrated in the Deep Basin gas area. Mannville crude oil and natural gas targets, including Sparky multi-lateral wells, resulted in 48 gross wells, or 33% of gross wells drilled in Alberta West during the year. Clearwater activity resulted in 25 gross wells drilled during the year, representing 17% of Alberta West drilling. Cardium drilling resulted in 18 gross wells, or 12% of gross wells drilled in the area in 2025.

Saskatchewan East

In 2025, 139 gross wells, or 48% 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, 97% of the wells drilled in 2025 were horizontal drills targeting crude oil plays.

In 2025, drilling was focussed on 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 42 locations or 40% of the gross royalty drilling in Saskatchewan East in 2025. Additionally, 29% of the gross royalty wells drilled in the Saskatchewan East region were in the Viking crude oil resource play. Freehold continues to see the benefit of well capitalized and active operators pursuing high netback opportunities in this area.

Permian (U.S. – Texas and New Mexico)

Freehold's Permian assets represent one of the most active areas within our portfolio. Drilling activity in 2025 resulted in 724 gross wells drilled on our Royalty Lands from a diverse group of public and private producers, many of which are focused exclusively in the Permian.

Eagle Ford (U.S. – Texas)

Freehold's Eagle Ford assets represent a core area within our U.S. portfolio. In 2025, 74 gross wells were drilled on our Royalty Lands in this area, underpinned by well capitalized investment grade producers committed to developing their assets in the area.

North Dakota and Other (U.S.)

In 2025, the primary plays or basins 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. In 2025, Freehold saw 21 wells drilled on its Royalty Lands across these areas.

Potash

Our potash acreage inventory is approximately 20,700 gross acres in 2025. This consists of leases we have issued on our mineral title to the various operators of nine 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 2025, we received approximately $1.7 million in royalty revenue from the production of approximately seven gross 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 2.1 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 crude 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 (as defined herein) on the Royalty Lands for the two most recently completed fiscal years.

Years Ended December 31[1]	**2025**	**2024**
Royalty Interest Properties (gross wells)		
Crude oil wells	1,048	1,095
Natural gas wells	59	22
Service/other wells	3	11
Dry and abandoned wells	0	12
Total	**1,110**	**1,140**
Success rate	**99.4%**	**98.9%**

1. Includes all drilling on properties acquired during the year from the effective date of the acquisitions.

In addition to our royalty interests, we own an immaterial amount of working interest properties in Canada. Our working interest assets represent less than 1.0% of our total production in 2025 and no volumes have been included in our reserves as at December 31, 2025.

Other Oil and Gas Information

Crude Oil and Natural Gas Wells

The following table sets forth, by province and state, the number of producing wells in which we have a royalty interest as at December 31, 2025. These producing well counts include wells associated with our ownership in 483 units, which would account for approximately 15,600 wells.

Royalty Interest Properties	Natural Gas Wells	Crude Oil Wells
Canada		
Alberta	11,863	6,460
Saskatchewan	568	6,921
British Columbia	68	4
Manitoba	1	717
Ontario	225	0
Canada Total	**12,725**	**14,102**

Royalty Interest Properties	Natural Gas Wells	Crude Oil Wells
United States		
Colorado	135	101
Louisiana	48	6
New Mexico	0	50
North Dakota	0	461
Oklahoma	17	65
Pennsylvania	40	2
Texas	892	8,330
Wyoming	28	4
United States Total	1,160	9,019
Total	**13,885**	**23,121**

The following table sets forth, by province, the number and status of wells in which we have a working interest as at December 31, 2025. There are no reserves assigned to any of these working interest properties.

	Natural Gas Wells			
	Producing		Non-Producing[3]	
Working Interest Properties	Gross	Net	Gross	Net
Alberta	4	1	46	11
Saskatchewan	-	-	2	1
British Columbia	1	-	-	-
Manitoba	-	-	-	-
Ontario	-	-	-	-
Total[1,2]	**5**	**1**	**48**	**12**

1. Columns may not add due to rounding.
2. Freehold does not hold any working interests in any crude 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 crude oil or natural gas. In addition to the wells listed in the table, Freehold has a working interest in 146 gross (37 net) crude oil wells, 61 gross (38 net) natural gas wells and 9 gross (4 net) other wells in Canada that are inactive and are not considered capable of producing any further volumes of crude 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, 2025:

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Canada			
Alberta	1,543,016	6,090	2,105
Saskatchewan	539,293	436	236
British Columbia	29,235	1,359	61
Manitoba	28,003	-	-
Ontario	1,890	-	-
Canada Total	2,141,438	7,885	2,402
United States			
Colorado	-	-	-
Louisiana	-	-	-
New Mexico	-	-	-
North Dakota	-	-	-
Oklahoma	-	-	-
Pennsylvania	-	-	-
Texas	1,159	-	-
Wyoming	-	-	-
United States Total	1,159	-	-
Total	**2,142,596**	**7,885**	**2,402**

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 117,000 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

Freehold was cash taxable in Canada and the United States in 2025 and expects to pay taxes in Canada and the United States in 2026.

The 2025 corporate income tax rate for Freehold was approximately 24% (2024 – 23%) and the expected corporate income tax rate for 2026 and future years is approximately 24%.

At December 31, 2025, Freehold's tax pools were $1.1 billion. Additional information is provided in Freehold's management's discussion and analysis for the year ended December 31, 2025 which is available on SEDAR+ at www.sedarplus.ca.

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 in 2025:

Canada	($000s)
Property acquisition costs[1]	
Proved properties	-
Undeveloped/unproved properties	$5,954
Development costs	-
Total	**$5,954**

1. As classified at the time of the acquisition.

The following table summarizes capital expenditures in the United States to acquire Royalty Lands in 2025:

United States	($000s)
Property acquisition costs[1]	
Proved properties	$5,406
Undeveloped/unproved properties	$26,071
Development costs	-
Total	**$31,477**

1. As classified at the time of the acquisition.

Production Estimates

The following tables set out the volume of gross and net production estimated for the year ended December 31, 2025 in the GLJ 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*".

CANADA

	Light and Medium Crude Oil		**Tight Oil**		**Heavy Crude Oil**	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)
Proved						
Developed producing	-	1,853	-	259	-	1,209
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	210	-	8	-	57
Total proved	-	2,063	-	267	-	1,266
Probable	-	100	-	12	-	66
Total proved plus probable[1]	**-**	**2,163**	**-**	**279**	**-**	**1,332**

	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	-	17,251	-	93	-	639
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	181	-	-	-	93
Total proved	-	17,432	-	93	-	732
Probable	-	365	-	1	-	43
Total proved plus probable[1]	**-**	**17,797**	**-**	**94**	**-**	**774**

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (boe/d)	Net (boe/d)
Proved				
Developed producing	-	750	-	7,069
Developed non-producing	-	-	-	-
Undeveloped	-	8	-	328
Total proved	-	758	-	7,397
Probable	-	23	-	269
Total proved plus probable[1]	**-**	**781**	**-**	**7,666**

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	-	2,332	-	6,657	-	996
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	361	-	967	-	154
Total proved	-	2,693	-	7,624	-	1,150
Probable	-	622	-	1,561	-	272
Total proved plus probable[1]	**-**	**3,316**	**-**	**9,185**	**-**	**1,422**

	Total Oil Equivalent	
Reserves Category	Gross (boe/d)	Net (boe/d)
Proved		
Developed producing	-	4,438
Developed non-producing	-	-
Undeveloped	-	677
Total proved	-	5,114
Probable	-	1,154
Total proved plus probable[1]	**-**	**6,269**

TOTAL

	Light and Medium Crude Oil		Tight Oil		Heavy Crude Oil	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)	Gross (bbls/d)	Net (bbls/d)
Proved						
Developed producing	-	1,853	-	2,591	-	1,209
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	210	-	369	-	57
Total proved	-	2,063	-	2,960	-	1,266
Probable	-	100	-	634	-	66
Total proved plus probable[1]	**-**	**2,163**	**-**	**3,595**	**-**	**1,332**

	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	-	17,251	-	93	-	7,296
Developed non-producing	-	-	-	-	-	-
Undeveloped	-	181	-	-	-	1,060
Total proved	-	17,432	-	93	-	8,356
Probable	-	365	-	1	-	1,604
Total proved plus probable[1]	**-**	**17,797**	**-**	**94**	**-**	**9,959**

	Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (bbls/d)	Net (bbls/d)	Gross (boe/d)	Net (boe/d)
Proved				
Developed producing	-	1,746	-	11,507
Developed non-producing	-	-	-	-
Undeveloped	-	162	-	1,005
Total proved	-	1,908	-	12,511
Probable	-	295	-	1,423
Total proved plus probable[1]	**-**	**2,203**	**-**	**13,935**

1. Columns may not add due to rounding.

Production History

The following tables summarize our production, product prices received, royalties paid, production and ad valorem taxes, operating expenses and resulting netback on a boe basis for the periods indicated below:

CANADA

	2025 Quarter Ended				2024 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)	2,452	2,681	2,831	2,738	2,878	2,906	3,056	3,097
Heavy Crude Oil (bbls/d)	1,619	1,481	1,557	1,552	1,516	1,315	1,348	1,300
Conventional Natural Gas[3] (Mcf/d)	22,267	22,453	23,195	24,652	25,042	23,931	25,556	25,735
NGL (bbls/d)	812	776	850	879	869	865	959	907
Combined (boe/d)	**8,594**	**8,680**	**9,104**	**9,278**	9,437	9,075	9,622	9,593
Average price realized								
Light and Medium Crude Oil[2] ($/bbl)	72.40	80.71	78.62	89.52	89.63	93.05	100.04	84.47
Heavy Crude Oil ($/bbl)	62.72	69.43	68.38	78.52	75.48	79.15	86.38	70.10
Conventional Natural Gas[3] ($/Mcf)	1.66	0.56	1.60	1.83	1.00	0.61	0.90	2.12
NGL ($/bbl)	39.35	47.06	42.94	51.18	48.09	48.82	52.52	49.35
Combined ($/boe)	**40.50**	**42.44**	**45.22**	**49.26**	46.53	47.52	51.50	47.13
Royalty expense[4]								
Light and Medium Crude Oil[2] ($/bbl)	-	0.03	0.01	0.07	0.20	0.11	0.12	-
Heavy Crude Oil ($/bbl)	-	0.03	0.01	0.07	0.20	0.11	0.12	-
Conventional Natural Gas[3] ($/Mcf)	-	-	0.01	-	0.01	(0.01)	-	-
NGL ($/bbl)	0.01	0.05	0.03	0.19	0.15	0.13	0.16	0.12
Combined ($/boe)	**-**	**0.02**	**0.04**	**0.04**	0.12	0.05	0.06	0.01
Operating expenses ($/boe)[5]								
Light and Medium Crude Oil[2] ($/bbl)	-	-	-	-	-	-	-	-
Heavy Crude Oil ($/bbl)	-	-	-	-	-	-	-	-
Conventional Natural Gas[3] ($/Mcf)	0.06	0.08	0.09	0.08	0.12	0.12	0.14	0.09
NGL ($/bbl)	-	-	-	-	-	-	-	-
Combined ($/boe)	**0.14**	**0.20**	**0.24**	**0.22**	0.31	0.31	0.38	0.23
Netback received[6,7]								
Light and Medium Crude Oil[2] ($/bbl)	72.40	80.68	78.61	89.44	89.44	92.93	99.92	84.46
Heavy Crude Oil ($/bbl)	62.72	69.40	68.37	78.44	75.29	79.03	86.26	70.09
Conventional Natural Gas[3] ($/Mcf)	1.61	0.49	1.49	1.75	0.87	0.50	0.76	2.04
NGL ($/bbl)	39.35	47.02	42.91	51.00	47.94	48.69	52.36	49.23
Combined ($/boe)	**40.36**	**42.22**	**44.94**	**49.00**	46.10	47.16	51.05	46.88

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 relate to working interest production and are comprised of direct costs incurred for natural gas production.
6. Per boe netbacks are calculated by subtracting per boe royalty expenses and operating costs from realized price.
7. Excludes income from potash and bonus consideration and lease rentals.

UNITED STATES[1]

	2025 Quarter Ended				2024 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)	4,004	3,981	4,108	4,142	3,418	3,174	3,495	2,997
Shale Gas (Mcf/d)	10,913	11,006	10,025	9,025	7,522	7,516	6,968	6,882
NGL (bbls/d)	1,877	1,559	1,701	1,324	1,197	1,107	943	977
Combined (boe/d)	**7,700**	**7,374**	**7,480**	**6,970**	5,869	5,533	5,599	5,121
Average price realized								
Tight Oil ($/bbl)	83.26	88.97	87.03	103.69	97.82	102.32	110.51	102.78
Shale Gas ($/Mcf)	2.21	2.48	2.23	3.57	2.17	1.17	0.52	2.21
NGL ($/bbl)	22.40	22.74	30.96	33.64	28.06	26.44	25.41	31.87
Combined ($/boe)	**51.89**	**56.54**	**57.83**	**72.64**	65.48	65.58	73.90	69.19
Production and ad valorem taxes								
Tight Oil ($/bbl)	3.93	4.22	3.97	5.26	3.48	4.59	4.64	4.76
Shale Gas ($/Mcf)	0.66	0.70	0.66	0.88	0.58	0.77	0.77	0.79
NGL ($/bbl)	3.93	4.22	3.97	5.26	3.48	4.59	4.64	4.76
Combined ($/boe)	**3.93**	**4.22**	**3.97**	**5.26**	3.48	4.59	4.64	4.76
Operating expenses ($/boe)								
Tight Oil ($/bbl)	-	-	-	-	-	-	-	-
Shale Gas ($/Mcf)	-	-	-	-	-	-	-	-
NGL ($/bbl)	-	-	-	-	-	-	-	-
Combined ($/boe)	-	-	-	-	-	-	-	-
Netback received[3]								
Tight Oil ($/bbl)	79.32	84.76	83.06	98.43	94.33	97.73	105.87	98.01
Shale Gas ($/Mcf)	1.56	1.78	1.57	2.69	1.59	0.41	(0.25)	1.41
NGL ($/bbl)	18.47	18.53	27.00	28.37	24.58	21.84	20.77	27.11
Combined ($/boe)	**47.96**	**52.32**	**53.86**	**67.37**	61.99	60.98	69.26	64.43

1. Denominated in Canadian dollars.
2. Represents net production from our Royalty Lands in the United States.
3. Per boe netbacks are calculated by subtracting per boe royalty expenses and operating costs from realized price.

The following table summarizes our average daily production from our Royalty Lands in important regions or fields for the year ended December 31, 2025:

	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	759	1,188	21,602	736	6,283
Saskatchewan East	1,916	364	1,530	93	2,628
Canada Total	**2,675**	**1,552**	**23,132**	**829**	**8,911**

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	1,400	3,018	565	2,469
Permian	2,490	5,551	966	4,381
North Dakota and Other	168	1,680	85	553
United States Total	**4,058**	**10,249**	**1,617**	**7,383**

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 respective environmental regulatory frameworks**.**

Freehold owns minor, legacy related working interests in natural gas properties. We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of these minor working interest properties upon abandonment. In 2025, no reserves have been assigned to these working interest assets.

Additional Information Concerning Abandonment, Decommissioning and Reclamation Costs

For the purposes of estimating Reserves Data in the GLJ Report, abandonment, decommissioning and reclamation costs for Freehold's Canadian working interest properties including wells (both active and inactive wells), pipelines and facilities have been taken into account. Freehold did not attribute any reserves to its Canadian working interest properties. The undiscounted amount of capital costs associated with abandonment and reclamation, reflected in the estimates of future net revenue associated with Freehold's Canadian proved reserves and proved plus probable reserves, is approximately $9.9 million. As Freehold only holds royalty interests in the United States and no working interests, for the purposes of the Ryder Scott Report on Freehold's United States assets, no deduction has been made for abandonment, decommissioning and reclamation costs as the Corporation has no liability for such costs on its royalty interest properties.

Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an individual well, facility and pipeline level based on the underlying characteristics of the related well, facility or pipeline. 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, 2025, which are available on SEDAR+ at www.sedarplus.ca.

Borrowings

Freehold has extendible revolving credit facilities with a total commitment of $500 million consisting of a $480 million syndicated facility and a $20 million operating facility. The syndicated facility can be increased up to $580 million under an accordion feature, subject to lenders' consent.

The current maturity date of the credit facilities is November 13, 2028. 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.

Depending on the type of borrowing, the credit facilities bear interest based on the lender's rates for Canadian prime loans, U.S. base rate loans, SOFR loans, CORRA loans or letters of credit, plus applicable margins. The applicable margin charged is dependent on the ratio of Freehold's long-term debt to earnings before interest, taxes, depreciation and amortization (EBITDA) on royalty interest properties. Under the credit facilities: (1) the

ratio of our long-term debt to EBITDA on royalty interest properties shall not at any time exceed 3.5 to 1.0; and (2) the ratio of our long-term debt to total 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 an $800 million 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 matters related to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing. Legislation has been enacted by, and agreements have been entered into between, various levels of government regarding the pricing and taxation of petroleum and natural gas, all of which should be carefully considered by investors in the Corporation. All current legislation is a matter of public record; however, the Corporation is unable to predict what additional legislation or amendments government may enact in the future.

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 activities associated with the exploration and production of crude oil and natural gas, including, among other matters: (i) permits for drilling wells and constructing related infrastructure; (ii) technical drilling and well requirements; (iii) permitted locations and access to operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restrictions on flaring and venting; (v) minimizing environmental impacts, including reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) abandonment and reclamation of impacted sites. To conduct crude oil and natural gas operations and remain in good standing with applicable regulations, 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 can be costly and breaches may result in fines or other sanctions.

The discussion below outlines some of the principal aspects of legislation, regulations, agreements, orders, directives and other pertinent conditions that impact the oil and gas industry in Western Canada where, as at December 31, 2025, the Corporation's Canadian assets are primarily located. While these matters do not affect the Corporation's operations in any manner that is materially different from the way they affect other similarly sized industry participants with comparable assets and operations, investors should consider such matters carefully.

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 regulation, 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

The price of crude oil, natural gas, and NGLs is negotiated between buyers and sellers. Various factors may influence prices, including both global and local supply and demand, product quality, distance to market, availability of transportation, value of refined products, prices of competing products, price of competing stock, contract terms, weather conditions, supply/demand balance, and other contractual provisions.

Transportation Constraints and Market Access

Despite having capacity to move crude oil, natural gas, and NGLs from Western Canada, much of this transportation infrastructure is oriented toward the United States. Market access remains constrained because limited capacity is available for deliveries to Eastern Canada and overseas markets. This reliance on U.S.-bound infrastructure continues to restrict Canada's ability to diversify export destinations. Many proposed projects that could broaden access, particularly those aimed at enabling greater movement to other international markets, have been cancelled or delayed due to regulatory hurdles, court challenges, and economic or socio-political factors.

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 Canadian constitutional law, the development and operation of interprovincial and international pipelines fall within federal jurisdiction and, under the *Canadian Energy Regulator Act*, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. In recent years, however, there has been 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 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.

In June 2025, Bill C-5 (the *One Canadian Economy Act*) came into force, granting the federal government authority to expedite approval of "national interest" infrastructure projects, including pipelines. While the legislation aims to reduce regulatory delays, it has drawn mixed reactions: industry stakeholders generally support its streamlining measures, whereas certain rights holders, particularly Indigenous groups, have expressed concerns regarding its implications. The federal government is currently engaged in consultations with provinces, territories, and Indigenous communities regarding implementation.

On November 27, 2025, the governments of Canada and Alberta signed a Memorandum of Understanding ("**MOU**") to collaborate on supporting the development of oil and gas resources, renewable energy, critical

minerals, and other resource sectors in Western Canada. The MOU includes a federal government commitment to not implement the Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations ("**Oil and Gas Emissions Cap**") and the commitment of both levels of government to design and commit to sector-specific stringency factors for large Alberta emitters under Alberta's Technology Innovation and Emissions Reduction Regulation ("**TIER**"), and to continue the annual carbon tax rate increase up to $130 per tonne.

The agreements to be established under the MOU are expected to be finalized in 2026 and 2027.

Pipelines in the United States

In the United States, transportation of crude oil is subject to rate and access regulation. The Federal Energy Regulatory Commission ("**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 2020, under the five-year re-determination, the FERC adjusted the index level used to determine annual changes to crude oil pipeline rate ceilings and determined that the Producer Price Index for Finished Goods plus 0.78% should be the index level 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

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system (which transports up to 540,000 bbls/d of light crude oil, light synthetic crude, and NGLs), to operate below the Straits of Mackinac, attempting to force the lines compromising this segment of the pipeline system to be shut down. Enbridge Inc. 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. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General appealed the decision. In June 2024, the Sixth Circuit Court of Appeals overturned the U.S. District Court's decision and remanded the Michigan's Attorney General lawsuit back to Michigan state court. In January 2025, oral arguments took place before the Michigan state court on cross motions for summary disposition and a decision is expected in early 2026.

In September 2022, the District Court of Wisconsin ruled in favour of the Bad River Band in its dispute with Enbridge Inc. over the Enbridge Line 5 pipeline system in that state. Stopping short of ordering the system to be shut down, the court ruled that the Bad River Band is entitled to financial compensation and ordered Enbridge Inc. to reroute the pipeline around Bad River territory within five years.

In October 2020, TC Energy Corporation ("**TC**") received federal approval to expand the Nova Gas Transmission Line system (the "**NGTL System**"). The NGTL System is currently implementing a $9.9 billion infrastructure program. In July 2024, TC announced an historic equity interest purchase agreement with an Indigenous-owned

investment partnership which will enable up to 72 Indigenous communities to become equity owners of the network of infrastructure assets spanning Western Canada; however, as of September 2024, the deal has been delayed.

In 2025, LNG Canada became fully operational as the country's first large-scale LNG export terminal, marking a significant milestone in Canada's emergence as a global LNG supplier. The project exported its first cargo from the Kitimat terminal in July 2025, and by September had already shipped ten cargoes to international markets, with export volumes continuing to rise thereafter. In addition, on August 6, 2025, JGC and Fluor were awarded a contract to update the Front-End Engineering and Design for the proposed Phase 2 expansion of LNG Canada, which aims to double the facility's annual LNG production capacity.

A wide range of energy infrastructure projects, including natural gas pipelines, crude oil pipelines, LNG export facilities, and related transmission upgrades, remain in various stages of development across Canada. These include projects that are under construction, as well as others that are proposed, awaiting regulatory approvals, or still pending final investment decisions. Together, these projects reflect a significant pipeline of potential development subject to evolving market conditions, regulatory processes, and investment decisions.

Land Tenure

Mineral Rights in Canada

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to crude oil and natural gas located within its borders. Provincial governments grant rights to explore for and produce crude oil and natural gas through leases, licences and permits (collectively referred to as "**leases**") for varying terms and subject to 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 crude oil and natural gas companies bid for leases necessary to explore for and produce provincially owned crude oil and natural gas. These leases generally have fixed terms but may be continued beyond their initial terms if the required conditions are satisfied.

Private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned crude oil and natural gas are granted by a lease or other contract on terms and conditions negotiated between the mineral rights holder and companies seeking to explore for and/or develop crude oil and natural gas reserves.

An additional category of mineral rights ownership is Canadian federal government ownership of mineral rights on First Nation reserve lands (as designated under the *Indian Act* (Canada)), which is managed and regulated by a separate government body under distinct legislation. The Corporation does not have operations or royalty interests on 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 crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop crude oil and natural gas reserves.

Surface Rights

To develop crude oil and natural gas resources, producers must also secure 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 are typically negotiated with the landowner. Where an agreement cannot be reached, 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.

Royalties and Incentives

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 for the production of resources. The royalty regime in a given province or state operate in conjunction with applicable federal and provincial or state taxes and are a significant factor in the profitability of oil sands projects and crude 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, although certain taxes and other charges on production or revenues may still apply. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

Producers and working interest owners of crude 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.

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

In the United States, royalties payable for crude oil and natural gas production vary depending on whether the crude oil and natural gas estate is owned by the federal government, the state government or a private landholder. Generally, the current federal royalty rate for onshore crude oil and gas is 12.5%. Production may also be subject to crude oil and natural gas severance taxes at the state level, although such severance taxes may include exemptions available for low-producing wells. Royalties payable under private crude oil and natural 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. These regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of substances produced in association with certain crude oil and gas operations, such as sulphur dioxide and nitrous oxide. Regulations also establish requirements for oilfield waste handling and storage, habitat protection and the proper operation, maintenance, abandonment

and reclamation of well, facility and pipeline sites. Compliance with these regulations can require significant expenditures and breaches may result in suspension or revocation of licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and greenhouse gas ("**GHG**") emissions (typically measured in terms of global warming potential and expressed as carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry. Companies engaged in hydraulic fracturing operations are subject to additional operational, regulatory, and reporting requirements.

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 regulations, 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.

In recent years, there has been a number of laws enacted by the federal government that have been challenged by provincial governments as exceeding the federal government's powers under Canadian constitutional law and interfering with provincial areas of jurisdiction. For instance, the passing of Bill C-69, which included the Canadian Energy Regulator Act and the Impact Assessment Act ("**IAA**") by the federal government created additional uncertainty as they appeared to grant broad discretion to Canada to veto infrastructure projects (including infrastructure projects under provincial jurisdiction) based on broad and undefined criteria like sustainability. In 2023, the Supreme Court of Canada found that the IAA was unconstitutional largely on the basis that it represented significant federal overreach into provincial affairs. Since the decision on the IAA, the federal government has paused the assessment process under the IAA, in particular, halting the designation of projects for assessment until new legislation is introduced. Disputes and uncertainty over jurisdiction between Canada and the provinces and over the scope of environmental legislation have created significant barriers to major infrastructure projects in Canada.

United States

Crude 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. Crude 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 ratability or fair apportionment of production from fields and individual wells.

Liability Management

Alberta maintains an orphan fund to cover the costs of suspending, abandoning, remediating, and reclaiming wells, facilities, or pipelines included in certain AER programs if a licensee or working interest participant becomes

insolvent or is otherwise unable to meet its obligations. The orphan fund is financed through levies imposed on industry participants and provincial loans. In March 2025, the Alberta government approved a $144 million levy for the Orphan Well Association's 2025/26 operating budget.

The Supreme Court of Canada's ("**SCC**") decision in *Orphan Well Association v. Grant Thornton* (often referred to as the "**Redwater**" decision) continues to shape Alberta's liability management regime. As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders or require security deposits before approving licence transfers during insolvency proceedings. Insolvent estates can no longer disclaim assets that have reached the end of their productive lives to prioritize valuable assets without first satisfying abandonment and reclamation obligations. The burden of a defunct licensee's obligations first falls on its working interest partners; thereafter, the AER may direct the orphan fund to assume care and custody and accelerate clean-up of wells or sites which do not have a responsible owner.

To address abandonment and reclamation liabilities, the AER periodically implements programs to encourage the decommissioning, remediation, and reclamation of inactive or marginal crude oil and natural gas infrastructure. In late 2025, the AER introduced mandatory annual closure spending requirements effective in 2026, reinforcing proactive liability reduction measures.

Similar to Alberta, British Columbia's regulator has moved away from formulaic liability management toward a holistic assessment of a permit holder's ability to meet abandonment and reclamation obligations. B.C. also maintains an orphan site program. The British Columbia Dormancy and Shutdown Regulation, amended effective April 1, 2025, establishes legally binding timelines for restoring crude oil and natural gas wells, aiming for 100% reclamation of currently dormant sites by 2036, with additional timelines for sites that became dormant between 2019 and 2023 and those becoming dormant after 2024.

Saskatchewan administers liability management through its Licensee Liability Rating program and the Inactive Liability Reduction Program, which mandates annual decommissioning expenditures. Saskatchewan's orphan fund, funded entirely by industry, continues to reclaim orphaned wells and facilities, with over 1,000 inactive sites restored as of early 2025.

Manitoba has not implemented a formal liability management rating program like those in other Western Canadian provinces. However, the province has processes in place to sell or abandon wells or facilities when a licensee or permittee fails to comply with a shutdown order, including rehabilitating abandoned sites and addressing any adverse property impacts.

Climate Change Regulation

Climate change regulation is a significant aspect of the operating environment for the oil and gas industry. International agreements, federal initiatives, and provincial programs continue to shape emissions reduction targets, carbon pricing mechanisms, and reporting requirements. Current frameworks include measures such as carbon taxes, emissions caps, and incentives for low-carbon technologies, with ongoing reviews aimed at tightening standards to meet climate commitments.

Canada

Canada is a signatory to the United Nations Framework Convention on Climate Change and ratified the Paris Agreement, committing to reduce greenhouse gas emissions by 30% below 2005 levels by 2030. In 2021, Canada strengthened this target to a 40–45% reduction by 2030 and net-zero emissions by 2050.

Canada has also pledged to reduce methane emissions from the oil and gas sector by 75% from 2012 levels by 2030; cap emissions from the oil and gas sector and phase out thermal coal exports by 2030. At the 2023 United Nations Climate Change Conference, Canada reaffirmed its commitment to transition away from fossil fuels and accelerate greenhouse gas reductions.

The Government of Canada launched the Pan-Canadian Framework on Clean Growth and Climate Change in 2016 and, in 2018, enacted the *Greenhouse Gas Pollution Pricing Act* This legislation established a federal carbon pricing system composed of two key elements: a fuel charge applied to fossil fuels, and an Output-Based Pricing System ("**OBPS**") for large industrial emitters. The federal regime applied nationwide unless a province or territory implemented a system that met or exceeded federal benchmarks. However, effective April 1, 2025, the federal government introduced regulations that eliminated the federal fuel charge and removed the requirement for provinces and territories to maintain a consumer-facing carbon price.

Canada also regulates methane emissions under the Federal Methane Regulations, which came into force in 2020 and initially targeted a 40–45% reduction below 2012 levels by 2025. In December 2023, the federal government proposed amendments to achieve a 75% reduction by 2030, introducing stricter limits, new prohibitions, and continuous monitoring requirements. These amendments are expected to take effect in 2027.

Additional federal measures include the Multi-Sector Air Pollutants Regulation, which limits emissions of nitrogen oxides and sulphur dioxide from industrial equipment, and commitments to cap oil and gas sector emissions and phase out thermal coal exports.

The *Canadian Net-Zero Emissions Accountability Act* ("**CNEAA**"), in force since 2021, commits Canada to achieving net-zero emissions by 2050. It establishes rolling five-year emissions reduction targets, requires detailed plans to meet each target, and mandates annual progress reporting.

Under the CNEAA, Canada released its 2030 Emissions Reduction Plan in March 2022, outlining measures to cut emissions 40-45% below 2005 levels by 2030. The plan includes incentives for electric vehicles ("**EV**"), renewable electricity, and an emissions cap for the oil and gas sector.

The federal government continues to implement and revise measures aimed at reducing greenhouse gas emissions, creating ongoing regulatory uncertainty for industry. The Clean Fuel Regulations, effective July 2023, impose increasingly stringent carbon-intensity reduction requirements and operate through a compliance credit market, which may affect fuel supply costs and credit availability. The federal Greenhouse Gas Offset Credit System, launched in 2022, allows eligible projects to generate offset credits for use under the federal OBPS, but future protocol development, credit supply, and pricing remain uncertain.

In November 2024, the federal government released proposed Oil and Gas Emissions Cap, which would establish a sector-wide cap-and-trade system for upstream oil and gas emissions. Although originally expected to take effect in 2026, the November 2025 federal budget introduced significant changes to Canada's climate-policy framework, creating uncertainty about whether the emissions cap will be implemented as proposed, revised, or withdrawn. Changes to federal carbon-pricing requirements, compliance mechanisms and potential new reporting obligations may increase compliance costs and affect the Corporation's operations, investment decisions, and long-term planning.

Canada's Carbon Management Strategy aims to deploy technologies such as carbon capture to help achieve climate targets. As part of this strategy, the federal government has committed $319 million over seven years to research and development.

In June 2024, the government enacted the Carbon Capture, Utilization, and Storage Investment Tax Credit, a refundable credit available for eligible projects from January 1, 2022, until December 31, 2040, with a 50% reduction in credit value beginning in 2031.

As discussed under "*Pipelines – Pipelines in Canada*", in November 2025, the governments of Canada and Alberta signed an MOU pursuant to which the federal government committed to not implement the Oil and Gas Emissions Cap and committed both levels of government to design and commit to sector-specific stringency factors for large Alberta emitters under Alberta's TIER, and to continue the annual carbon tax rate increase up to $130 per tonne.

In February 2026, the federal government introduced an updated national automotive strategy that includes more than $3 billion in planned financial commitments to support industry expansion, modernization, and diversification into additional export markets. As part of this initiative, the federal government will implement a new program to lower the cost of EVs for Canadians, introduce new EV purchase and lease incentives for individuals and businesses, expand charging infrastructure, and advance a broader trade framework intended to enhance the competitiveness of the automotive sector. It also replaces the Electric Vehicle Availability Standard (which required automakers to sell an increasing percentage of zero emission light-duty vehicles, reaching 100% by 2035) with updated GHG emissions standards and new targets of achieving 75% EV sales by 2035 and 90% by 2040. The Corporation is unable to predict how this new automotive strategy will impact the demand for fossil fuels and Canadian energy products.

Provincial

In December 2016, the *Oil Sands Emissions Limit Act* (Alberta) 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 emitted roughly 85 megatonnes of GHG emissions in 2024, well below the 100 megatonne limit.

On January 1, 2020, Alberta's TIER regulation came into effect for large emitters. It meets the federal benchmark's stringency requirements, allowing relevant facilities to remain under TIER rather than the federal OBPS. Since its introduction, TIER has undergone various amendments and program updates intended to refine compliance mechanisms and maintain alignment with federal benchmark stringency requirements.

In contrast, Saskatchewan and Manitoba do not have provincial equivalents, so the federal OBPS applies in full to their large industrial emitters. British Columbia, having implemented its own provincial OBPS on April 1, 2024, is exempt from the federal system as its program meets federal equivalency standards.

Alberta committed to reducing methane emissions by 45% from 2014 levels by 2025 and achieved this goal three years early. The province enacted the Methane Emission Reduction Regulation on January 1, 2020. Later that year, Alberta and Canada signed a five-year equivalency agreement exempting Alberta from the Federal Methane Regulations. In October 2025, the parties renewed the agreement, with some modifications, extending the exemption through 2030.

United States

In the United States, the U.S. Environmental Protection Agency has finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. In addition, certain states have taken measures to reduce emissions of greenhouse gases primarily through the development of GHG emission inventories and/or regional greenhouse gas cap-and-trade programs. States have also imposed increasingly

stringent requirements related to the venting or flaring of gas during oil and natural gas operations. The U.S. has withdrawn from the Paris Agreement and other international climate initiatives making it difficult to assess the timing or effect greenhouse gas regulations on our operations and financial results. In addition to the federal legislative and regulatory changes, in several states, the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to crude oil and natural gas facilities.

Indigenous Rights in Canada

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 on 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* ("**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 federally 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.

As of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP (the "**Implementation Secretariat**"), consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP's, and implementing efforts to educate federal departments on UNDRIP principles. On June 21, 2023, the Implementation Secretariat released Canada's UNDRIP Action Plan (the "**Action Plan**") with respect to aligning federal laws with UNDRIP, which has a 2023-2028 implementation timeframe. In August 2025, the Canadian federal government tabled its Fourth Annual Progress Report on implementation of the UNDRIP Act, which provides various progress updates, including on the implementation of the Action Plan.

The federal government is in the process of developing various regulatory regimes that could create new requirements when doing business with Indigenous groups and on or near First Nation lands, for example, the *National Strategy Respecting Environmental Racism and Environmental Justice Act* which received royal assent in June 2024 and the new Indigenous co-administration agreement provisions of the *Impact Assessment Act* for which regulations, policy, guidance and procedures are forthcoming.

On June 29, 2021, the B.C. Supreme Court's *Yahey v. British Columbia* held that cumulative impacts of industrial development on the traditional territory of Blueberry River First Nation ("**BRFN**") breached BRFN's Treaty 8 rights.

On January 18, 2023, B.C. and BRFN signed the Blueberry River First Nations Implementation Agreement ("**BRFN Agreement**"), introducing key measures such as a $200 million restoration fund, ecosystem-based land-use planning, limits on new oil and gas development, and revenue-sharing provisions. Under the BRFN Agreement, BRFN will receive $87.5 million over three years, with potential for additional benefits. In July 2024, BRFN filed a civil claim challenging the first implementation plan, highlighting concerns about execution.

The BRFN Agreement has served as a template for other Treaty 8 arrangements. Later in January 2023, B.C. and four First Nations (Fort Nelson, Saulteau, Halfway River, and Doig River) reached consensus on a collaborative approach to land and resource planning, adopting similar principles to implement cumulative effects management, new land-use plans, and revenue-sharing. However, two of these Nations later sued the B.C. government, alleging deception, misrepresentation, and withholding of information during negotiations. These disputes underscore the implementation challenges of such agreements.

Similar claims have been brought by First Nations in Alberta, including Beaver Lake Cree Nation's ("**BLCN**") claim against the Government of Alberta in 2008 and Duncan's First Nation's lawsuit against the Government of Alberta in 2022. After years of litigation, the BLCN case led to an SCC decision which established a new legal test for advance costs in public interest litigation. This ruling clarified that First Nations should not have to exhaust community resources or impoverish themselves to pursue constitutional claims, setting an important precedent for access to justice in treaty rights cases. The long-term impacts of these lawsuits on the Canadian oil and gas industry remain uncertain.

Recent British Columbia court decisions have the potential to influence the interpretation of Aboriginal title and the duty to consult framework in the province. In *Cowichan Tribes v. Canada (Attorney General)*, the Supreme Court of British Columbia declared portions of the City of Richmond to be subject to Aboriginal title, a finding that raises unresolved questions regarding the interaction between Aboriginal title and existing fee simple ownership. In *Gitxaala v. British Columbia (Chief Gold Commissioner)*, the British Columbia Court of Appeal held that British Columbia's DRIPA incorporates UNDRIP into domestic law and creates legally enforceable obligations on the province, including positive duties to ensure that provincial laws are consistent with UNDRIP. Premier David Eby has since announced plans to amend DRIPA to limit judicial involvement in that process.

While these developments may have limited direct application in Alberta given Alberta's treaty landscape and the absence of province-level UNDRIP implementation legislation, they underscore the rapidly evolving nature of Indigenous rights jurisprudence. Indigenous rights claims may still arise in Alberta on different factual or legal grounds, and these decisions nonetheless highlight the increasing importance of early, proactive, and sustained engagement with Indigenous Nations in regulatory, land-use, and project-development contexts.

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 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 crude oil and natural gas acquired, produced, or discovered by the Corporation. The Corporation and its partners and royalty payors ability to market its crude oil and natural gas may depend upon their 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 of the reserves in which the Corporation has interests 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, tariffs, royalties, land tenure, allowable production, the export of crude oil and natural gas and many other aspects of the oil and gas business may also affect the Corporation and its partners and royalty payors.

Crude 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, actions of the Organization of Petroleum Exporting Countries ("**OPEC+**"), political uncertainties, sanctions imposed on certain oil producing nations by other countries, the Russian-Ukrainian war, conflicts in the Middle East (including the recent attacks by the U.S. and Israel on Iran and Iranian retaliation), geopolitical developments in Venezuela, or other adverse economic or political developments in the United States, South America, Europe, or Asia. Additionally, the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Prices for crude 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 crude 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 crude 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 crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers 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 Market Access*".

Geopolitical Risks

The Corporation's results may 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 on which the Corporation relies. 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.

Significant changes or developments in United States laws and policies, such as laws and policies surrounding international trade, foreign affairs, manufacturing and development, and investment in the territories and countries where we or our customers operate, can materially adversely affect our business and financial statements. In particular, the current U.S.-Canada tariff environment remains highly dynamic and uncertain. Legislative or regulatory changes by the U.S. administration could materially impact the Corporation's operations and financial condition. In March 2025, the United States imposed a series of tariffs on goods imported from Canada and other countries, triggering a de facto global trade war, and prompting Canada and several trading partners to implement retaliatory measures. Since then, tariff policies have continued to evolve, creating ongoing uncertainty regarding U.S. support for existing trade agreements, including USMCA.

At present, the United States maintains tariffs on a range of Canadian exports, including steel and aluminum, automobiles and automotive parts, copper, lumber, and certain wooden products. Canada has implemented reciprocal tariffs on these categories. Additionally, U.S. tariffs apply to Canadian potash and energy products that do not qualify for USMCA exemptions. On February 20, 2025, the U.S. Supreme Court ("**SCOTUS**") issued its decision regarding the authority of the Trump administration to impose tariffs without congressional approval, ultimately deciding that the President does not have such authority under applicable legislation. In response to the SCOTUS decision, the Trump administration has indicated that it intends to impose alternative tariffs or adopt other trade measures on its trading partners, including Canada. SCOTUS' decision, the Trump's administration's response and the ongoing USMCA review add further uncertainty regarding whether crude oil, natural gas, and NGL exports to the U.S. could ultimately be subject to tariffs or other trade measures. These dynamics influence export costs, market access, and demand for Canadian energy products. The impact of continuing or new tariffs, other trade measures and the ongoing USMCA review, on the Canadian economy and Canadian energy producers is uncertain.

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, or 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. The success of these initiatives may decrease demand for the Corporation's or its partners' or royalty payors' products.

A change in federal, provincial, state or municipal governments in Canada or the United States may have an impact on the directions taken by such governments on matters that may impact the oil and gas industry, including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic, resulting in a rise in civil disobedience surrounding crude 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*".

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to crude oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for crude oil and natural gas. In recent years, 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 crude oil and natural gas products. The Corporation cannot predict the impact of changing demand for crude 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 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, third party challenges to regulatory decisions and orders can reduce the efficiency of the regulation, as the implementation of decisions and orders may be delayed resulting in uncertainty and interruption to the business of the oil and gas industry. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation"*.

To conduct crude oil and natural gas operations, the Corporation and its partners' and royalty payors' 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*".

Royalty Regimes

Governments in the jurisdictions in which the Corporation has assets may adopt new royalty regimes, or modify the existing royalty regimes, which may impact 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*".

Middle East Conflict

The Corporation's business may be adversely affected by geopolitical conflicts abroad. Hostilities that began in October 2023 between Israel and Hamas have evolved into a broader regional conflict. The Syrian Assad regime collapsed in late 2025, and the political climate in Syria remains in flux.

In June 2025, U.S. airspace strikes targeted Iranian nuclear facilities at Fordow, Natanz, and Isfahan, prompting Iranian missile attacks on U.S. assets in Qatar. A ceasefire between Hamas and Israel has held since mid-2025, but tensions remain high, with sporadic clashes continuing in Gaza and southern Lebanon.

On February 28, 2026, the U.S. and Israel launched a large scale coordinated missile and airstrike campaign across Iran striking multiple military and governmental sites. Supreme Leader Ayatollah Ali Khamenei and various other senior regime leaders were killed in the campaign. Iran immediately retaliated with missile and drone attacks targeting U.S. and Israeli assets across the region as well as neighbouring Middle East countries. This conflict has resulted and is expected to continue to result in disruptions to global energy supply and transportation routes.

These developments present continuing risks to regional stability in the Middle East, a critical hub of global crude oil and gas production. The duration and long-term consequences of the conflict remain uncertain, particularly regarding future Middle Eastern oil and gas output and the movement of those commodities worldwide. Any sustained or intensified conflict could further disrupt supply chains, increase volatility in global energy markets, and adversely affect the global economy. It is uncertain how these developments will impact the Canadian oil and gas industry and the Corporation.

Russian-Ukrainian War

The Corporation's business may be adversely affected by geopolitical conflicts abroad. Russia's invasion of Ukraine in February 2022 has developed into a prolonged and intense conflict, with heavy fighting continuing in eastern Ukraine and ongoing missile and drone attacks. The North Atlantic Treaty Organization ("**NATO**") and allied nations, including Canada, have provided substantial military and financial support to Ukraine, while maintaining strict sanctions against Russia. Although peace negotiations have advanced, no comprehensive settlement has been reached, and territorial and security issues remain unresolved. These developments pose ongoing risks to regional stability, global energy and industrial supply chains, and international markets, which could negatively impact the world economy, the Canadian oil and gas industry, and the Corporation.

U.S.-Venezuela Conflict

The Corporation's business could be adversely impacted by geopolitical developments affecting global crude oil markets. On January 3, 2026, United States military forces conducted an operation in Caracas, Venezuela, resulting in the capture of President Nicolás Maduro and his spouse, Cilia Flores. Subsequent statements by U.S. leadership indicated an intention to administer Venezuela temporarily and facilitate significant investment by American oil companies in Venezuela's petroleum sector. These actions have drawn widespread international attention, and the extent of resulting political and economic repercussions remains uncertain. Given that the United States is the primary destination for Canadian crude oil exports, increased U.S. access to Venezuela's substantial reserves could reduce U.S. demand for Canadian crude oil and negatively affect pricing and market competitiveness.

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 encounter 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 would 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 Rife Royalties Shared Mineral Title Ownership

Freehold and Rife Royalties share mineral title ownership rights in a substantial land base in Western Canada. Generally, Rife Royalties 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 Rife Royalties holds these rights in trust for Freehold. Rife Royalties holds mineral rights in trust for Freehold representing approximately 6.1% of Freehold's total royalty production for 2025. Prior to the termination of the Management Agreement, as both Freehold and Rife Royalties were managed by Rife, collection of the royalty payments that Rife Royalties received in trust for Freehold were managed by Rife. Upon termination of the Management Agreement, Freehold and Rife Royalties entered into a trust assets administration and management agreement dated January 1, 2026, pursuant to which Rife Royalties has agreed to partially assign the lessor interest in respect of Freehold's beneficial mineral title ownership to Freehold or delegated authority to Freehold to enforce all of the lessor rights and obligations in respect of Freehold's beneficial mineral title ownership; however, if the lessee does not recognize such partial assignment or delegated authority, Rife Royalties (or if Rife Royalties sells its interest in such assets, any new owner of such assets) would still be obligated to hold such royalty payments in trust for Freehold. In such circumstances, Freehold could be delayed in receiving royalty payments and depending on the counterparties involved collection of such royalty payments could 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 crude oil 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

Most 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

Crude oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability, and the ability of its partners and royalty payors to find, acquire, develop and commercially produce crude 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 crude oil and natural gas.

Future crude 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.

Crude oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to crude oil and natural gas wells, production facilities, other property 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.

Crude oil and natural gas production operations are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a 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 it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs. See "*Risk Factors – Insurance*".

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 and 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 encounter financial difficulty. This 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 effect on the Corporation's financial and operational results.

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 crude 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 crude 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.

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 a licence or lease, fails to meet a specific requirement of the 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.

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.

Inflation and Interest Rates

The Corporation's financial performance and cash flows may be adversely affected by inflationary pressures and fluctuations in interest rates. Inflation can lead to increased operating costs through higher prices for labour, equipment, materials, and services, as well as contribute to supply chain disruptions and regulatory changes. If the Corporation is unable to effectively manage these cost increases, project economics and future development decisions may be negatively impacted.

Although interest rates have begun to decline, they remained elevated for an extended period as central banks implemented measures to curb inflation. Higher borrowing costs during these periods may affect the Corporation's financing expenses and reduce returns on capital projects. Sustained periods of elevated interest rates can also slow economic growth, reduce energy demand, depress commodity prices, and limit industry activity. The duration and combined impact of inflationary pressures and interest rate volatility on energy demand, commodity pricing, and the Corporation's operations remain uncertain.

Project Risks

The ability of the Corporation and its royalty payors to execute projects and market crude 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 ability of royalty payors to raise required funds;
- 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, extreme cold 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 gas industry by various levels of government and governmental agencies.

As a result of these factors, the Corporation or its royalty payors may 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 crude 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. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities, pipeline systems or railway lines in Canada continues to affect the crude oil and natural gas industry and limits the ability to transport produced crude oil and natural gas to market. In particular, the limited pipeline capacity to tidewater and the lack of liquified natural gas facilities in Canada significantly impacts the ability of Canadian oil and natural gas companies to export their products outside of North America which limits demand for their products and results in lower prices. This limited ability to export crude oil and natural gas outside of North America puts Canadian oil and natural gas companies at greater risk with the United States potential imposition of tariffs on Canadian imports into the United States. The inability to export crude oil and natural gas could result in the Corporation's or its partners' and royalty payors' inability to realize the full economic potential of its production or in a reduction of the price the Corporation or its partners and royalty payors receives for their products.

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 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 crude 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 crude 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 crude 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 potentially material variations in the estimated reserves.

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, including actual production levels, supply and demand for crude oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation and taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's crude 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, crude oil and natural gas properties and in the marketing of crude oil and natural gas. In particular, the Corporation competes with other companies for the acquisition of royalty interests in crude 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 crude oil and natural gas include price, process, 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 a reasonable 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 potentially 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, potentially in a material way.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand, and additives under pressure into rock formations that were previously unproductive to stimulate the production of crude 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 crude oil, NGLs 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 crude oil and natural 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, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which would ultimately have a detrimental effect on the financial condition, results of operations, and cash flows of the Corporation.

The Corporation's royalty payors must dispose of the fluids produced from crude oil and natural gas production operations, including produced water. 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. 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 crude oil and gas extraction process, separated from the crude 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 crude 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 crude 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 crude 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 liabilities and potentially increased capital expenditures and operating costs. Crude oil and gas exploration and development has the potential to impact environmental quality through land disturbance, biodiversity impacts, and emissions to air and water. Landowners are increasingly demanding a minimization of surface footprint and some require offsets or mitigation measures to ensure land and biodiversity remain pristine and protected. The discharge of crude oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. In November 2024, the federal government published a draft of the proposed *Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations*, which, if enacted as drafted, would cap emissions from a range of industrial activities in the oil and gas sector, establish a cap-and-trade system for emissions allowances, and require facility operators to comply with various reporting and remittance obligations. Such proposed regulations, which could affect investor confidence, increase decarbonization initiatives and lead to production cuts, are expected to be finalized and come into force in 2026.

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.

Amendments to the *Competition Act* introduced in June 2024 prohibit companies from making false or misleading environmental claims. The new rules are complex and uncertain, and initially led many companies to suspend

voluntary sustainability reporting. While private rights of action for greenwashing came into effect in June 2025, *Budget 2025 Implementation Act, No. 1* subsequently removed this access and clarified substantiation requirements to address unintended consequences. Despite these improvements, the regulatory landscape continues to evolve and penalties for non-compliance remain significant, including up to the greater of $10 million for a first order, $15 million for subsequent orders, or 3% of global annual revenues. Companies making voluntary environmental disclosures face ongoing risk of liability and reputational harm.

Climate Change

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the United Nations 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 crude oil, liquids and natural gas. The majority of countries, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement and in November 2025 at COP30 in Brazil, Canada reaffirmed its commitments to transitioning away from fossil fuels in line with the Paris Agreement.

Transition Risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting 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 multi-lateral 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 such measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes, methane fees 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 crude oil and 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 crude 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. Individuals, governmental 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 currently 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.

Due to long-term risks from environmental policy changes, regulations, legal challenges, and market shifts related to climate change, recent efforts have targeted the financial sector. Investment advisors banks, pension funds, universities, and other institutional investors are engaging companies on climate action, using voting rights, and reallocating capital toward low-carbon assets while divesting from high-emission businesses. Stakeholders are also pressuring insurers and banks to stop financing or insuring crude oil, gas, and related infrastructure. These

efforts may negatively impact the Corporation's operations, securities demand and pricing, and its cost and access to capital.

Climate-related regulations and reporting standards continue to evolve. In June 2023, the International Sustainability Standards Board ("**ISSB**") issued two global disclosure standards, IFRS S1 and S2, to promote consistent, comparable, and reliable environmental reporting. In December 2024, the Canadian Sustainability Standards Board ("**CSSB**") finalized similar Canadian standards, CSDS 1 and CSDS 2 (the "**Canadian Standards**"). In December 2025, the ISSB announced targeted amendments to IFRS S2; whether the Canadian Standards will be revised remains uncertain. Meanwhile, in April 2025, due to significant changes in the global economic and geopolitical landscape, the Canadian Securities Administrators paused work on its own climate disclosure initiative. If the Corporation is not able to meet future climate-related 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 – Climate Change Regulation*".

Physical Risks

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.

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 crude 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 crude oil and natural gas production, it could also result in an increase in the price for certain goods used in 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 of funds 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.

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

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition and development of crude 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 those 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 crude 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.

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 crude 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 of or production from 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 expected to require credit facilities from time to time, as needed to fund its operations and meet its financial obligations. 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, such financing 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 could 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 crude 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 crude oil or natural gas prices.

Similarly, from time to time, the Corporation may enter into agreements to fix the exchange rate of Canadian dollars 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.

Reliance on Skilled Workforce and Key Personnel

The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Corporation's business plans which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospectuses.

Competition for qualified personnel in the oil and natural gas industry is intense and 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. The Corporation does not have any key personnel insurance in place. Contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees may have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation is unable to retain current employees, successfully complete effective knowledge transfers and/or recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Diluent Supply

Heavy crude 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 crude 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 crude oil and bitumen to market. An increase to the cost of bringing heavy crude 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 crude oil and bitumen assets.

Insurance

The Corporation's involvement in the exploration for and development of crude oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blowouts, sour gas leaks, 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 premiums 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 increase and the Corporation could incur significant costs.

Reputational Risk Associated with the Corporation's Operations

The Corporation's business, operations or financial condition may be negatively impacted by any negative public opinion toward 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 such groups' opposition to certain crude oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or 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 the environment 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 crude 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 toward 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 crude oil and natural gas operations on the environment, environmental damage resulting from spills of petroleum products during transportation and Indigenous rights, have affected certain investors' sentiments toward the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they are no longer willing to fund or invest in crude 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 of Directors 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 willing to invest in the oil and natural gas industry and more specifically, the Corporation, may limit the Corporation's access to capital, thereby 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.

Indigenous groups across Canada have established and asserted treaty entitlements, title to land and Aboriginal rights. Although there are no treaty, title or rights claims on lands where the Corporation has an interest, no certainty exists that any lands currently unaffected by such claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on the Corporation's operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies upon 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. In 2021, the British Columbia Supreme Court 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. In 2023, the Government of British Columbia and the First Nations group have come to an agreement relating to further industrial activities in the area, which will have an impact on such industrial activities in the area. The developments in northeastern British Columbia relating to Indigenous rights, may lead to similar claims of cumulative effects across Canada in other areas covered by treaties. The long-term impacts and associated risks of the decision on the Canadian oil and natural gas industry and the Corporation remain uncertain.

The federal government has enacted federal legislation to implement the UNDRIP, and British Columbia has adopted similar provincial legislation under DRIPA. The practical implications of these statutes have remained uncertain; however, recent judicial decisions in 2025 provide important guidance.

In February 2025, the Federal Court in *Kebaowek First Nation v. Canadian Nuclear Laboratories* directed a decision-maker to reconsider whether the duty to consult and accommodate had been satisfied in light of UNDRIP principles. In December 2025, the British Columbia Court of Appeal *in Gitxaala v. British Columbia (Chief Gold Commissioner)* held that DRIPA imposes immediate, positive statutory obligations on the provincial government, including taking concrete and diligent steps to align provincial laws with UNDRIP. British Columbia Premier, David Eby, has since announced that the government plans to amend DRIPA to remove the courts' ability to scrutinize that alignment process.

Although the scope of UNDRIP implementation continues to evolve, these recent decisions demonstrate a judicial willingness to confer substantive legal effect on UNDRIP both in British Columbia and federally. Additional processes may be created and legislation associated with project development and operations may be amended or introduced, 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.

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 changing perceptions of the crude oil and natural gas market. In recent years, the volatility of commodities prices 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 that only purchase securities included in such indices.

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.

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, restrictions under contracts on the payment of dividends 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 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.

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. To continue to manage the growth of the Corporation effectively, the Corporation will need to continue to implement and improve its operational and financial systems and to train, manage and potentially

expand its employee base. If the Corporation is unable to deal with such growth, it may have a material adverse effect on the Corporation's business, financial condition, results of operations or prospects.

Litigation

In the normal course of the Corporation's operations, it may become involved in, be named as a party to, or be the subject of, legal proceedings, including regulatory proceedings, tax proceedings or 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 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 at such time. 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 effect on the Corporation's financial condition.

For additional information, see "*Legal Proceedings and Regulatory Actions*".

Income Taxes

The Corporation is subject to taxes in Canada and the U.S. Due to economic and political conditions, tax rates in various jurisdictions may be subject to significant change. Our effective tax rates could be affected by changes in the mix of earnings in countries with differing statutory tax rates, changes in the valuation of deferred tax assets and liabilities, or changes in tax laws or their interpretation.

Additionally, 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.

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, state and foreign tax legislation however the Canada Revenue Agency, the United States Internal Revenue Service and other 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. We regularly assess the likelihood of an adverse outcome resulting from examinations of our tax returns and other tax matters to determine the adequacy of our provision for taxes. There can be no assurance as to the outcome of these examinations. If our effective tax rates were to increase, particularly in Canada or the United States, or if the ultimate determination of our taxes owed is for an amount in excess of amounts previously accrued, our financial condition and operating results could be materially adversely affected.

Freehold has been assessed by the CRA to deny the deduction of certain non-capital losses claimed and carried forward in its 2015, 2018, 2019, 2021 and 2022 tax returns. Freehold is defending its tax filing position and expects it will be successful however, if Freehold is not successful it will 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, municipal, 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). Certain crude 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. Phishing attacks (i.e., fraudulent attempts to obtain sensitive information such as passwords, financial details, or funds) have become increasingly sophisticated. A successful attack could result in loss of financial resources, theft of critical data, or compromise of the Corporation's technology infrastructure. Employees are frequent targets, often through emails that appear legitimate, but direct recipients to fraudulent websites, request confidential information, or install malware such as "Trojan horse" programs.

Increasingly, social media is used as a vehicle to carry out 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 the Corporation's 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 and may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Additionally, the Corporation's information technology systems may incorporate the use of artificial intelligence ("**AI**") and development of such capabilities remain ongoing. As with new innovations, AI presents risks, challenges and unintended consequences that could affect its adoption, and therefore the Corporation's business. The Corporation's IT systems may incorporate AI, and development of these capabilities is ongoing. AI introduces risks and unintended consequences that could affect adoption and business operations. Algorithms and training methods may be flawed, and reliance on AI without adequate safeguards can lead to inaccurate outcomes or operational vulnerabilities.

AI also poses data privacy, cyber-security, and intellectual property risks. Improper use may result in unauthorized disclosure of sensitive information or outputs that infringe copyrights, patents, or privacy rights. As legal and regulatory frameworks for AI remain uncertain, future compliance obligations could impose significant costs or limit the Corporation's ability to integrate AI tools.

The protection of customer, employee, and company data is critical to the Corporation's business. The regulatory environment in Canada surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and evolving requirements. Certain legislation, including the *Personal Information Protection and Electronic Documents Act* in Canada, requires documents to be securely destroyed to avoid identity theft and inadvertent disclosure of confidential and sensitive information. A significant breach of customer, employee, or company data could attract a substantial amount of media attention, damage the Corporation's customer relationships and reputation, and result in lost sales, fines, or lawsuits. In addition, an increasing number of countries have introduced and/or increased enforcement of comprehensive privacy laws or are expected to do so. The continued emphasis on information security as well as increasing concerns about government surveillance may lead customers to request the Corporation to take additional measures to enhance security and/or assume higher liability under its contracts. As a result of legislative initiatives and customer demands, the Corporation may have to modify its operations to further improve data security. Any such modifications may result in increased expenses and operational complexity, and adversely affect its reputation, 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*".

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on acquiring and managing crude oil and natural gas royalties in both Canada and the United States. 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 Statements May Prove Inaccurate

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

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

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

Events such as natural disasters, war, riots, or civil unrest can severely disrupt recovery efforts in affected regions. This may have a material adverse impact on the Corporation, its partners and royalty payors, its customers, and their operations. Other risks include terrorist attacks, public health crises (such as epidemics, pandemics, or new infectious diseases), trade and infrastructure disruptions, civil disobedience, national emergencies, acts of war, and technological attacks. These events can create volatility and disrupt supply chains, operations, workforce mobility, and financial markets. Such disruptions may lead to a significant decline in economic activity in Canada and globally, reduce demand for crude oil and natural gas, and affect interest rates, credit ratings, inflation, and overall business conditions. These factors could negatively impact the Corporation, its partners, and royalty payors' reputation, business, financial condition, and operations, and may worsen other risks identified herein.

Public Opposition

The crude oil and natural gas properties, wells and facilities of the Corporation and its partners and royalty payors could, 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 crude oil and natural gas production operations) and 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 such groups and attempting to address their concerns may require the Corporation and its partners and royalty payors to incur significant and unanticipated capital and operating expenditures.

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 for the period ended December 31, 2025, and will likely be a PFIC in subsequent years. If we are a PFIC for any year during a Shareholder's holding period, dividends to and any gain from the sale of Common Shares by Shareholders who are United States taxpayers should be subject to the regimes of United States federal income taxation applicable to PFICs and such Shareholders may be subject to additional reporting requirements. Freehold, in order to allow Shareholders the ability to make a Qualified Electing Fund election, will use reasonable efforts to post a PFIC Annual Information Statement on its website; however, there is no assurance that Freehold will timely provide such required information. The rules dealing with PFICs, the Qualified Electing Fund election and other available elections are

very complex. Shareholders who are United States taxpayers should consult with and rely solely upon their own tax advisors regarding the application of the PFIC rules to them in their particular circumstances and the reporting requirements with respect to owning shares in a PFIC.

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 163,960,334 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.

Well-Known Seasoned Issuer Base Shelf Prospectus

On December 17, 2025, Freehold filed a base shelf prospectus under the well-known seasoned issuer ("**WKSI**") provisions of National Instrument 44-102 *Shelf Distributions* ("**NI 44-102**"). The Corporation has reviewed its eligibility to rely on such provisions and, as at the date of this AIF, continues to satisfy the conditions under subsections 9B.2(1) or (2) of NI 44-102 to qualify as a WKSI.

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:

COMMON SHARE PRICE TRADING RANGE (TSX)

	(Cdn$ per Common Share)			
	High	**Low**	**Close**	**Volume Traded**
2025				
January	13.64	12.48	12.50	17,249,314
February	13.01	12.06	12.60	12,599,600
March	13.05	11.80	12.74	12,985,003
April	12.91	10.53	11.41	16,475,327
May	12.72	11.10	12.04	15,830,748
June	13.27	12.24	12.79	17,179,441
July	13.65	12.69	13.34	11,925,988
August	13.56	12.94	13.38	10,371,409
September	14.08	13.08	13.78	14,662,537
October	14.37	13.41	14.19	13,716,313
November	15.23	13.86	14.90	12,454,716
December	15.51	14.66	15.19	11,205,830
2026				
January	16.93	14.57	16.38	15,328,147
February	17.72	15.80	17.59	12,419,441
March (1-10)	18.22	17.43	17.83	5,662,425

Prior Sales

Other than DSUs and RSUs, Freehold did not issue any securities of a class that are not listed or quoted on the marketplace during the year ended December 31, 2025.

We issued the following DSUs and RSUs (including notional DSUs and RSUs resulting from dividends) redeemable to acquire an equal number of Common Shares (less tax withholding) pursuant to the Deferred and Restricted Share Unit Plan during the year ended December 31, 2025:

Date	Number and Type of Share Units	Deemed Price per Share Unit
January 1, 2025	35,964 DSUs[2]	$12.79
January 1, 2025	29,710 RSUs[2]	$12.79
January 15, 2025	3,772 DSUs[1]	$13.28
January 15, 2025	205 RSUs[1]	$13.28
February 18, 2025	4,239 DSUs[1]	$12.66
February 18, 2025	344 RSUs[1]	$12.66
March 17, 2025	4,286 DSUs[1]	$12.61
March 17, 2025	348 RSUs[1]	$12.61
March 31, 2025	3,648 DSUs[2]	$12.85
April 15, 2025	4,867 DSUs[1]	$11.25
April 15, 2025	393 RSUs[1]	$11.25
May 15, 2025	4,405 DSUs[1]	$12.53
May 15, 2025	356 RSUs[1]	$12.53
June 16, 2025	4,276 DSUs[1]	$13.00
June 16, 2025	345 RSUs[1]	$13.00
June 30, 2025	3,645 DSUs[2]	$12.86
July 15, 2025	4,328 DSUs[1]	$13.01
July 15, 2025	348 RSUs[1]	$13.01
August 15, 2025	4,250 DSUs[1]	$13.34
August 15, 2025	341 RSUs[1]	$13.34
September 15, 2025	4,266 DSUs[1]	$13.38
September 15, 2025	343 RSUs[1]	$13.38
September 29, 2025	3,338 DSUs[2]	$14.04
October 15, 2025	4,228 DSUs[1]	$13.66
October 15, 2025	338 RSUs[1]	$13.66
November 17, 2025	3,958 DSUs[1]	$14.69
November 17, 2025	316 RSUs[1]	$14.69
December 15, 2025	3,551 DSUs[1]	$15.26
December 15, 2025	306 RSUs[1]	$15.26
December 31, 2025	3,055 DSUs[2]	$15.34

1. Issued for 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 or subject to a contractual restriction on transfer.

Dividends

The payment of dividends by the 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.

Monthly dividends of Freehold are currently declared for Shareholders of record as of the last business 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 Shareholders. 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 expected commodity prices, foreign exchange rates, economic conditions, production volumes, taxes payable, the repurchase of shares and Freehold's capacity to finance operating and investing obligations and opportunities.

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, 2026, Freehold has declared a cash dividend of:

- $0.09 per Common Share for Shareholders of record on January 30, 2026, which was paid on February 17, 2026;
- $0.09 per Common Share for Shareholders of record on February 27, 2026, which is payable on March 16, 2026; and
- $0.09 per Common Share for Shareholders of record on March 31, 2026, which is payable on April 15, 2026.

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
2023		
January 31, 2023	February 15, 2023	0.0900
February 28, 2023	March 15, 2023	0.0900
March 31, 2023	April 17, 2023	0.0900
April 28, 2023	May 15, 2023	0.0900
May 31, 2023	June 15, 2023	0.0900
June 30, 2023	July 17, 2023	0.0900
July 31, 2023	August 15, 2023	0.0900
August 31, 2023	September 15, 2023	0.0900
September 29, 2023	October 16, 2023	0.0900
October 31, 2023	November 15, 2023	0.0900
November 30, 2023	December 15, 2023	0.0900
December 29, 2023	January 15, 2024	0.0900
Total		1.0800

Record Date	Payment Date	Cdn$ per Share
2024		
January 31, 2024	February 15, 2024	0.0900
February 29, 2024	March 15, 2024	0.0900
March 28, 2024	April 15, 2024	0.0900
April 30, 2024	May 15, 2024	0.0900
May 31, 2024	June 17, 2024	0.0900
June 28, 2024	July 15, 2024	0.0900
July 31, 2024	August 15, 2024	0.0900
August 30, 2024	September 16, 2024	0.0900
September 30, 2024	October 15, 2024	0.0900
October 31, 2024	November 15, 2024	0.0900
November 29, 2024	December 16, 2024	0.0900
December 31, 2024	January 15, 2025	0.0900
Total		1.0800

Record Date	Payment Date	Cdn$ per Share
2025		
January 31, 2025	February 18, 2025	0.0900
February 28, 2025	March 17, 2025	0.0900
March 31, 2025	April 15, 2025	0.0900
April 30, 2025	May 15, 2025	0.0900
May 30, 2025	June 16, 2025	0.0900
June 30, 2025	July 15, 2025	0.0900
July 31, 2025	August 15, 2025	0.0900
August 29, 2025	September 15, 2025	0.0900
September 30, 2025	October 15, 2025	0.0900
October 31, 2025	November 17, 2025	0.0900
November 28, 2025	December 15, 2025	0.0900
December 31, 2025	January 15, 2026	0.0900
Total		1.0800

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, Freehold believes it should be classified as a PFIC under United States federal income tax principles for the period ended December 31, 2025, and will likely be a PFIC in subsequent years. If we are a PFIC for any year during a Shareholder's holding period, dividends to and any gain from the sale of Common Shares by Shareholders who are United States taxpayers should 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, will use reasonable efforts to post 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.

United States 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

Nominee Agreement

The Nominee Agreement provides that if CN Pension Trust Funds and its affiliated entities hold 10% or more of the issued and outstanding Common Shares, CNID will have the right to nominate for election one individual as a director of Freehold. If the individual nominated by CNID fails to get elected the Nominee Agreement provides CNID with the right to have an observer present at all meetings of directors of Freehold. The Nominee Agreement will terminate when and if CN Pension Trust Funds and any affiliated entities, hold less than 10% of the issued and outstanding Common Shares. The CN Pension Trust Funds holds, directly or indirectly, approximately 16.0% of the outstanding Common Shares and as a result, has the right to nominate one individual as a director of Freehold.

Board of Directors of Freehold

As at March 11, 2026, Freehold's Board of Directors is 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 or State of Residence	Position with Freehold	Principal Occupation	Director Since
Gary R. Bugeaud[1,2] Alberta, Canada	Director	Corporate Director	May 14, 2015
Maureen E. Howe[1,3] British Columbia, Canada	Director	Corporate Director	February 1, 2022
J. Douglas Kay[2,3] Alberta, Canada	Director	Corporate Director	May 11, 2016
Kimberley E. Lynch Proctor[1,2] Alberta, Canada	Director	Corporate Director	May 7, 2024
Valerie A. Mitchell[2,3] Oklahoma, United States	Director	President & Chief Operating Officer, Troy Energy	June 1, 2022
Marvin F. Romanow Alberta, Canada	Chair of the Board of Directors	Corporate Director	May 14, 2015
Mathieu M. Roy[4] Quebec, Canada	Director	Managing Director, Global Equities & Private Assets, CNID	May 7, 2024
David M. Spyker Alberta, Canada	President & Chief Executive Officer & Director	President & Chief Executive Officer, Freehold	January 20, 2021
Aidan M. Walsh[1,3] Alberta, Canada	Director	Corporate Director	May 15, 2013

1. Member of Audit, Finance and Risk Committee. Ms. Howe is Chair of the Audit, Finance and Risk Committee.
2. Member of Governance, Nominating and Compensation Committee. Mr. Kay is Chair of the Governance, Nominating and Compensation Committee.

3. Member of Reserves Committee. Mr. Walsh is Chair of the Reserves Committee.
4. Mr. Roy is a nominee of CNID under the Nominee Agreement and formerly was a nominee of the Manager under the Governance Agreement.

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 and Principal Occupation	Officer Since
David M. Spyker Alberta, Canada	President & Chief Executive Officer & Director	November 28, 2016
Shaina B. Morihira Alberta, Canada	Vice President, Finance and Chief Financial Officer	June 4, 2025
Lisa N. Farstad Alberta, Canada	Vice President, Corporate Services	March 1, 2020
Susan J. Nagy Alberta, Canada	Vice President, Business Development Commercial	April 1, 2023
Colin J. Strem Alberta, Canada	Vice President, Business Development Technical	April 30, 2025

Prior to the termination of the Management Agreement, each of the officers of Freehold was an employee of Rife and prior to the delivery of the Notice of Termination, each of such officers was an officer of both Freehold and Rife (other than Mr. Strem who was solely an officer of Rife prior to April 2025). Except as described herein, including 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 11, 2026, the directors and executive officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 689,286 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 26,258,310 Common Shares (approximately 16.0%) as at March 11, 2026.

The following is a brief description of the backgrounds of the directors and executive 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 holds a Bachelor of Commerce (Finance) and a Bachelor of Laws from the University of Saskatchewan. Mr. Bugeaud holds the ICD.D designation from 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. 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 45 years of diverse responsibilities with Canadian based oil and gas exploration and production companies. Mr. Kay holds a Bachelor of Economics 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 is a former director and Chair of Westbrick Energy Ltd., the Explorers and Producers Association of Canada (EPAC) and a former director of CAPP.

Kimberley E. Lynch Proctor

Ms. Lynch Proctor is a corporate director with over 25 years of experience as a business executive, lawyer, and accountant. She was the Chief Financial Officer and General Counsel of KERN Partners, an energy focused private equity firm, from 2009 to 2016 and prior thereto a practicing lawyer and Chartered Professional Accountant with Felesky Flynn LLP, Bennett Jones LLP, and Deloitte, respectively, advising on international and domestic transactions. Ms. Lynch Proctor is currently a director of Paramount Resources Ltd. and is also on the Board of Trustees of Alaris Equity Partners Income Trust. She is a former director of MEG Energy Corp. Ms. Lynch Proctor obtained a Bachelor of Commerce and a Bachelor of Laws from the University of Calgary, a Master of Laws from New York University, is a Chartered Professional Accountant and holds an ICD.D designation from the Institute of Corporate Directors.

Valerie A. Mitchell

Ms. Mitchell is a Corporate Director with over 25 years of experience in the energy industry. Since March 2020, Ms. Mitchell has been the President and Chief Operating Officer of Troy Energy, a private independent oil and gas acquisition, development, and exploration company based in Oklahoma City. From 2016 through 2020, Ms. Mitchell was the Chief Executive Officer and a director of Corterra Energy, LLC, a private equity backed exploration and production company based in Tulsa, Oklahoma. She is currently a director and member of the Audit Committee of NCS Multistage Holdings Inc. Ms. Mitchell holds a Bachelor of Science (Honours) in Chemical Engineering from the University of Missouri. She holds the NACD.DC designation from the National Association of Corporate Directors.

Marvin F. Romanow

Mr. Romanow is a Corporate Director, Executive in Residence at the University of Saskatchewan, and retired oil and gas industry executive with over 40 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 holds a Master of Business Administration 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 and is a former director of CAPP.

Mathieu M. Roy

Mr. Roy is Managing Director, Global Equities & Private Assets of CNID which manages one of the largest corporate pension funds in Canada. Mr. Roy has 22 years of experience in capital markets, including more than 18 years at CNID. Mr. Roy holds a bachelor's and master's degree in finance from the University of Sherbrooke and is a Chartered Financial Analyst. Mr. Roy is a director and the Chair of Rife Resources, Rife Royalties and Rife Holdings Ltd.

Aidan M. Walsh

Mr. Walsh is a Corporate Director. Prior to April 30, 2020, he was Chief Executive Officer of Baccalieu Energy Inc., 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 holds a Bachelor of Engineering in Mechanical Engineering from Memorial University of Newfoundland and Labrador and a Master of Business Administration from the University of Calgary. He is a life 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) and a former director of CAPP.

David M. Spyker

Mr. Spyker was appointed President and Chief Executive Officer of Freehold in January 2021. He joined Rife in 2016 and served in various senior executive leadership positions for both Freehold and Rife, providing leadership and strategic oversight to both organizations. Effective May 2025, as part of the termination of the Management Agreement with Rife, he relinquished his obligations to Rife and currently serves exclusively as President and Chief Executive Officer of Freehold. Mr. Spyker has 38 years of experience and leadership in the upstream oil and gas industry, with extensive knowledge of, and insight into, operations, asset evaluation, business development, and mergers and acquisitions. He holds a Bachelor of Science 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 also a member of the Institute of Corporate Directors.

Shaina B. Morihira

Ms. Morihira was appointed Vice President, Finance and Chief Financial Officer of Freehold in June 2025. Prior to joining Freehold, Ms. Morihira spent nine years at Enerplus Corporation with her most recent role as Vice President, Finance. While at Enerplus Corporation, Ms. Morihira led the treasury, corporate reporting, tax and risk management functions and worked closely with the senior leadership team to support the company's strategic objectives. Ms. Morihira is a Chartered Professional Accountant and a Chartered Accountant and holds a Master of Professional Accounting from the University of Saskatchewan and a Bachelor of Commerce from the University of Calgary.

Lisa N. Farstad

Ms. Farstad was appointed Vice President, Corporate Services of Freehold in March 2020. From March 2020 until April 2025, she served in this role for both Freehold and Rife. Effective May 2025, as part of the termination of the Management Agreement with Rife, she relinquished her obligations to Rife. Ms. Farstad joined Freehold and Rife in September 2015 as Manager, Human Resources and Information Services. Prior thereto, she spent 14 years with Bonavista Energy Corporation in various human resources roles, including Manager, Human Resources. Ms. Farstad holds a Bachelor of Arts from the University of Alberta and a Human Resources Management Certificate from the University of Calgary.

Susan J. Nagy

Ms. Nagy was appointed Vice President, Business Development Commercial of Freehold in April 2025. From April 2023 to April 2025, Ms. Nagy served as Vice President, Business Development of both Freehold and Rife. Effective May 2025, as part of the termination of the Management Agreement with Rife, she relinquished her obligations to Rife. She joined Freehold and Rife in April 2008 and held various positions of increasing seniority within the Land and Business Development groups. Ms. Nagy holds a Bachelor of Commerce (with Distinction) from the University of Calgary and is an active member of the Canadian Association of Land and Energy Professionals (CALEP), Petroleum Acquisition & Divestment Association (PADA), and the American Association of Professional Landmen (AAPL).

Colin J. Strem

Mr. Strem was appointed Vice President, Business Development Technical of Freehold in April 2025. He has more than 25 years of industry experience, with expertise in drilling and completions, production and reservoir development, and acquisitions and divestitures. Prior to joining Freehold, Mr. Strem held several senior roles at Rife from 2022 to 2025, most recently Vice President, Operations. Before joining Rife, he held senior technical and leadership positions with Chevron Canada Limited, NAL Resources Limited, and WesternZagros Resources Ltd. Mr. Strem holds a Bachelor of Science in Mechanical Engineering from the University of Alberta and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Corporate Cease Trade Orders or Bankruptcies

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; or (ii) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, after the director or executive officer ceased to be a director, chief executive officer or chief

financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. None of the directors or executive officers of Freehold is as at the date of the AIF, 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.

Personal Bankruptcies

None of the directors or executive officers of Freehold nor any Shareholder holding sufficient number of securities of Freehold to affect materially the control of Freehold has, 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, Finance & Risk Committee

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

Composition of Audit, Finance & Risk Committee (the "Audit Committee")

Freehold's Audit Committee consists of Ms. Maureen Howe (Chair), Mr. Gary Bugeaud, Ms. Kim Lynch Proctor, 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*. Two members of the Audit Committee are Audit Financial Experts. See "*Directors and Officers*" for further information.

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	
	2025	**2024**
Audit fees[1]	$482,685	$526,960
Audit-related fees[2]	$66,000	-
Tax fees[3]	$7,700	$56,898
All other fees	-	-
Total	**$556,385**	**$583,858**

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.
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 2025 and 2024, $7,700 and $42,003, respectively, of such fees were related to tax compliance and tax preparation and the remainder was for advisory services.

Conflicts of Interest

Circumstances may arise where officers of Freehold or members of the Board of Directors serve as directors or officers of corporations that are in competition with the interests of Freehold. Accordingly, conflicts of interest may arise which could influence these persons in evaluating possible acquisitions or in generally acting on behalf of the Corporation, notwithstanding that they are bound by the provisions of the ABCA to act at all times in good faith in the interest of the Corporation and to disclose such conflicts to the Corporation if and when they arise. Other than as otherwise described herein, to the best of its knowledge, the Corporation is not aware of the existence of any material conflicts of interest between any of their directors and officers as of the date hereof.

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 prior years' Canadian income tax returns were assessed by the CRA to deny the deduction of $222 million in non-capital losses that were acquired through a 2015 business combination (the "**Assessments**"). Pursuant to the Assessments, denied non-capital losses claims resulted in taxes, interest, and penalties totaling an estimated $62 million. Freehold objected to the Assessments and provided deposits totaling $31 million with

taxation authorities as at March 11, 2026. The CRA has issued a notice of confirmation regarding their Assessments. Freehold has filed a notice of appeal with the Tax Court of Canada in respect of the Assessment and the Department of Justice has filed its reply. Freehold has received legal advice that it should be entitled to deduct the non-capital losses and as such, expects to be successful in defending its filed tax positions.

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.

CN Pension Trust Funds participated in Freehold's December 13, 2024 bought deal equity offering by purchasing 1,153,846 Common Shares at a price of $13.00 per share for gross proceeds of $15 million. See "*General Development of the Business – Year Ended December 31, 2024*".

The Manager and Rife are wholly-owned subsidiaries of the CN Pension Trust Funds which held, directly or indirectly, 26,258,310 Common Shares as at March 11, 2026, representing approximately 16.0% of the outstanding Common Shares. Prior to the termination of the Management Agreement, the Manager received certain compensation and reimbursement for a portion of general and administrative expenses for providing management services to Freehold, FHT and the Partnership.

Under the terms of the Management Agreement, the Manager was issued Common Shares (or the lump sum cash equivalent) quarterly as payment of the Management Fee. In 2023 and 2024, an aggregate of 55,000 and 22,000 Common Shares, respectively, were issued to the Manager as payment of the Management Fee. In 2025, Freehold elected to settle the Management Fee through cash payments equivalent to the value of 5,500 Common Shares per quarter (in accordance with the terms of the Management Agreement). Upon delivery of the Notice of Termination, Freehold and the Manager agreed that Freehold would no longer be required to pay the Management Fee for any period after April 30, 2025. As a result, Freehold paid a pro-rated Management Fee for the second quarter of 2025 equal to the value of 1,833 Common Shares (or an aggregate of 7,333 for the period from January 1, 2025 through April 30, 2025).

Prior to the termination of the Management Agreement, the Manager was reimbursed for general and administrative expenses incurred by Rife on behalf of Freehold. General and administrative expenses were generally charged to Freehold based on time spent and direct costs incurred by Rife in fulfilling the obligations of the Manager to Freehold pursuant to the Management Agreement. In 2025, 2024 and 2023, general and administrative expenses of $14.0 million, $15.3 million and $15.1 million, respectively, were charged by the Manager for time and direct costs incurred by Rife on behalf of Freehold.

All transactions during 2025 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, with 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 since or during the most recently completed financial year, or before the most recently completed financial year but which are still in effect, are the following:

- the Nominee Agreement dated January 1, 2026, as described under the heading "*Directors and Officers – Nominee Agreement*"; and
- the agreement governing our credit facilities between Freehold and its lenders dated May 9, 2018, as amended and restated June 26, 2024 and further amended November 13, 2025, November 14, 2024, December 13, 2024 and November 13, 2025, 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 GLJ and Ryder Scott, our current independent engineering evaluators, and Trimble, our former 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 GLJ, Ryder Scott and Trimble 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.sedarplus.ca. 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 11, 2026, which relates to our Annual Meeting of Shareholders to be held on May 13, 2026. Additional financial information is provided in Freehold's consolidated financial statements for the year ended December 31, 2025 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:

Vice President, Finance and Chief Financial Officer
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**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2025. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2025, 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, 2025, 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)			
			Audited ($000s)	Evaluated ($000s)	Reviewed ($000s)	Total ($000s)
GLJ Ltd.	December 31, 2025	Canada	-	$854,313	-	$854,313
RSC Group, Inc.	December 31, 2025	United States	-	$981,354	-	$981,354
TOTALS			-	$1,835,667	-	$1,835,667

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:

GLJ Ltd.

(signed) "*Chad P. Lemke*"

Chad P. Lemke, P.Eng.
Calgary, Alberta, Canada

March 11, 2026

RSC Group, Inc.

(signed) "*Andrew J. Thompson*"

Andrew J. Thompson, P. Eng.
Calgary, Alberta, Canada

March 11, 2026

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 crude 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) "*Shaina B. Morihira*"
Shaina B. Morihira
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 11th day of March, 2026.

APPENDIX C

AUDIT, FINANCE & RISK COMMITTEE MANDATE

Role and Objective

The Audit, Finance and Risk 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;

5. To strengthen the role of the independent directors by facilitating in-depth discussions between directors on the Committee, management and the external auditors;

6. To promote Freehold's strong financial health; and

7. To assist the Board with identification and management of risk.

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. At least one member of the Committee shall be a financial expert. Someone shall be considered a financial expert if they are or were a chief financial officer, chartered accountant, certified management accountant, fellow chartered accountant (FCA), fellow certified practicing accountant (FCPA), or partner of an accounting firm, or someone with an equivalent skillset in the determination of the Board.

3. The Board will have the power to appoint the Committee Chair.

4. 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 will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting(s) 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 key financial matters, including but not limited to those pertaining to foreign currency, interest rates, capital markets, debt and tax.

4. 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.

5. Review the financial statements, prospectuses, management's 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.

6. 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.

7. 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.

8. 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.

9. Review, on a quarterly basis, the risk management policies and procedures of Freehold, including with respect to hedging, litigation, cyber security and insurance, including D&O insurance.

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

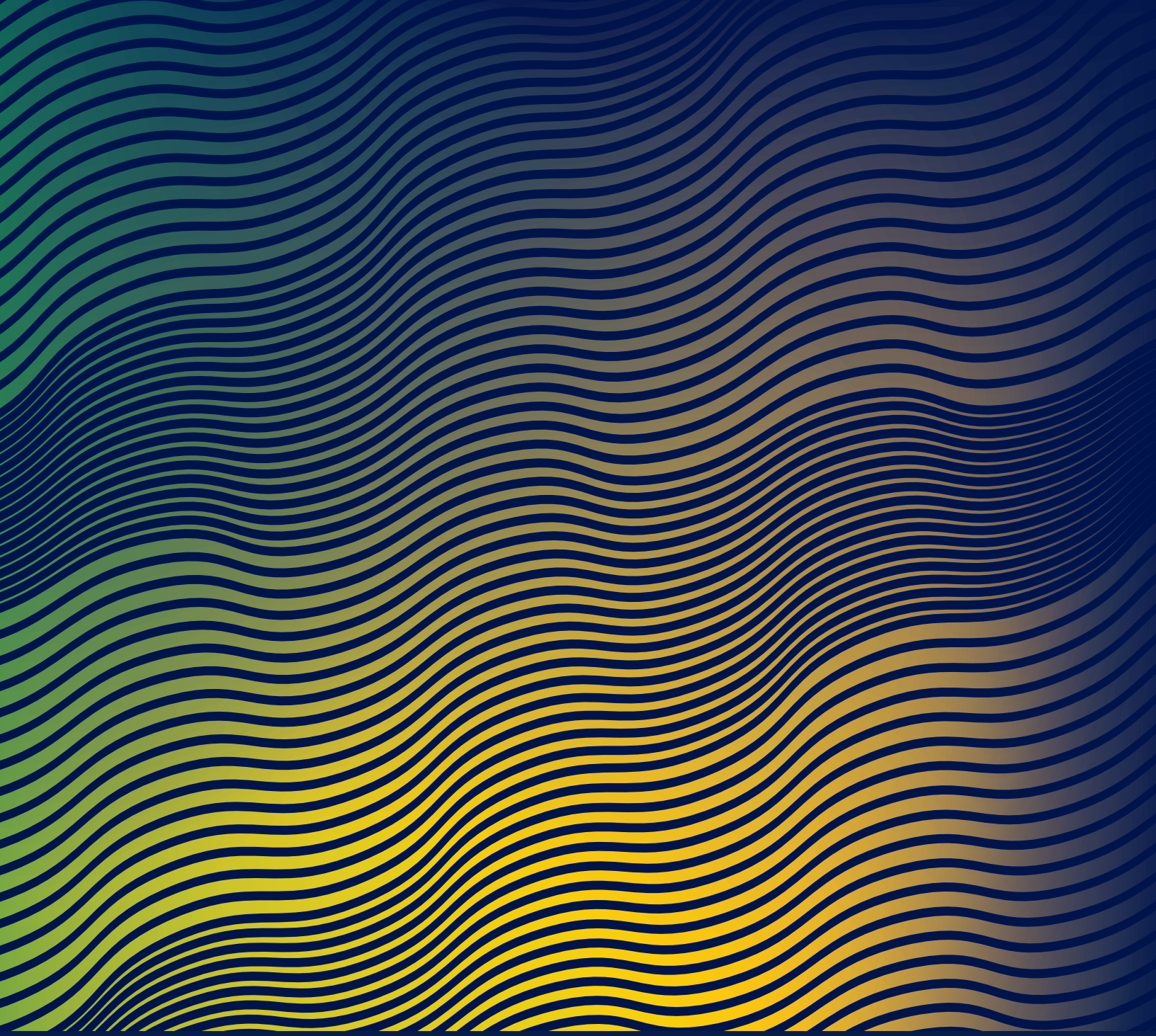
11. Establish procedures for:
    a. the receipt, retention and treatment of complaints received by Freehold regarding accounting, internal accounting controls or auditing matters; and
    b. the confidential, anonymous submission by Freehold employees of concerns regarding questionable accounting or auditing matters.

12. 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).

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

14. 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.

Adopted January 1, 2011; last amended January 1, 2026



FREEHOLD
ROYALTIES

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