ANNUAL INFORMATION FORM

For the Year Ended December 31, 2024

Dated March 26, 2025

CARDINAL
ENERGY LTD.

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GLOSSARY

Certain capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board or **Board of Directors** means our board of directors.

Broadview Energy means Broadview Energy Ltd.

Cardinal, we, us or **our** means Cardinal Energy Ltd.

Venturion means Venturion Oil Corp.

Reserves

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

Consolidated Reserve Report mean the consolidated reserve report prepared by GLJ dated February 21, 2025 and effective as at December 31, 2024 consolidating the results of the GLJ Report and the McDaniel Report.

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

GLJ means GLJ Ltd., independent petroleum consultants of Calgary, Alberta.

GLJ Report means the report prepared by GLJ dated February 21, 2025 and effective as at December 31, 2024.

McDaniel means McDaniel & Associates Consultants Ltd, independent petroleum consultants of Calgary, Alberta.

McDaniel Report means the report prepared by McDaniel dated February 21, 2025 and effective as at December 31, 2024.

Propak means Propak Systems Ltd.

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

Securities and Other Terms

8.00% Debentures means our 8.00% convertible unsecured subordinated debentures which were due December 31, 2022.

2020 Warrants means our common share purchase warrants which were issued on December 30, 2020, each of which entitled the holder to acquire one Common Share at an exercise price of $0.55 for the period commencing on June 30, 2021 to December 30, 2023.

2021 Secured Notes means our second lien secured notes which were issued on July 14, 2021.

2021 Warrants means our common share purchase warrants which were issued on July 14, 2021, each of which entitled the holder to acquire one Common Share at an exercise price of $3.16 for the period commencing on December 14, 2021 to July 14, 2024.

Common Shares means our common shares as presently constituted.

Credit Facility means our $275 million syndicated credit facility, as more particularly described under the heading "*Description of our Capital Structure – Credit Facility*".

Debenture Indenture means the indenture dated January 3, 2025, between us and the Debenture Trustee as supplemented by the Supplemental Indenture, providing for the creation and issuance of the Initial Debentures and the Second Series Debentures.

Debenture Offering means the offering of Second Series Debentures more particularly described under the heading "*General Development of Our Business – History and Development – Recent Developments*".

Debenture Trustee means Odyssey Trust Company or its successor or successors in their capacity as debenture trustee of the Debentures pursuant to the Debenture Indenture.

Debentureholders means holders of Initial Debentures and/or Second Series Debentures, as applicable.

Debentures means, collectively, the Initial Debentures and Second Series Debentures.

Initial Debentures means our 7.75% senior subordinated unsecured debentures issued on January 3, 2025 and due March 31, 2030 with a par value of $1,000, as more particularly described under the heading "*Description of our Capital Structure – Debentures*".

Reford Project means our steam-assisted gravity drainage project in Reford, Saskatchewan.

Second Series Debentures means our 8.25% senior subordinated unsecured debentures initially issued on March 3, 2025 and due September 30, 2030 with a par value of $1,000, as more particularly described under the heading "*Description of our Capital Structure – Debentures*".

SEDAR+ means the System for Electronic Document Analysis and Retrieval+, an Internet-based filing system developed for the Canadian Securities Administrators, which facilitates, among other things, the electronic filing of securities information and the public dissemination of Canadian securities information collected in the securities filing process.

Shareholders mean the holders of Common Shares from time to time.

Supplemental Indenture means the first supplemental indenture dated as of March 4, 2025 between us and the Debenture Trustee providing for the creation and issuance of the Second Series Debentures.

Unit Offering means the offering of Units more particularly described under the heading "*General Development of Our Business – History and Development – Developments in 2024*" and "*General Development of Our Business – History and Development – Recent Developments*".

Units means our units which were issued for $1,000 per Unit on January 3, 2025, each of which was comprised of one Initial Debenture and 65 Warrants.

Warrant Agent means Odyssey Trust Company or its successor or successors in their capacity as warrant agent of the Warrants pursuant to the Warrant Indenture.

Warrant Indenture means the warrant indenture dated January 3, 2025 creating and setting forth the terms of the Warrants between us and Odyssey Trust Company, as warrant agent.

Warrants means our common share purchase warrants, each of which entitles the holder to acquire one Common Share at an exercise price of $7.00, subject to adjustment, for the period commencing on January 3, 2025 to January 3, 2028, as more particularly described under the heading "*Description of our Capital Structure – Warrants*".

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf/d	thousand cubic feet per day
Bbls	barrels	MMcf	million cubic feet
Bbls/d	barrels per day	MMbtu	million British Thermal Units
Mbbls	thousand barrels	NGLs	natural gas liquids
Mcf	thousand cubic feet		

Other	
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
ARO	abandonment and reclamation obligations
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
CO_2	carbon dioxide
EOR	enhanced oil recovery
ESG	environmental, social and governance
GHG	greenhouse gas
m^3	cubic metres
MBoe	thousand barrels of oil equivalent
MMBoe	million barrels of oil equivalent
SAGD	steam assisted gravity drainage
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s or M$	thousands of dollars
$MM	millions of dollars

CONVERSIONS

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

To Convert From	To	Multiply By
acres	hectares	0.405
Bbls	cubic metres	0.159
cubic metres	cubic feet	35.315
cubic metres	Bbls	6.289
feet	metres	0.305
gigajoules	MMbtu	0.950
hectares	acres	2.471
kilometers	miles	0.621
Mcf	cubic metres	28.317
metres	feet	3.281
miles	kilometers	1.609
MMbtu	gigajoules	1.0526

CONVENTIONS

Certain terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to future events or our future performance. All information and statements, other than statements of historical fact, contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "could", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology.

In addition, there are forward-looking statements in this Annual Information Form under the headings: "*General Development of Our Business*" as to our business plans, focus, strategies and objectives, production decline rates, the benefits of and future performance expectations relating to our Reford Project, expectations relating to the fixed price agreement with Propak and the use of proceeds from the Unit Offering and the Debenture Offering; "*General Description of Our Business*" as to our business plans, focus, strategies and objectives, production decline rates, and our ESG plans and initiatives; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, royalties, operating costs, development costs, abandonment and reclamation costs, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our undeveloped reserves, future developments costs, our plans to fund future developments costs through a combination of internally generated cash flow from operating activities, debt and equity issuances, our future abandonment and reclamation obligations; our future capital programs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our drilling and development plans and opportunities, optimization and operating plans, decline rates, anticipated land expiries, hedging and marketing policies, abandonment and reclamation obligations, tax horizon, future production, matters relating to our Reford Project and future SAGD projects; and "*Dividend Policy*" as to our dividend policy and the future payment of dividends.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- timing and anticipated benefits of our development programs, including the SAGD developments;
- the future development potential of our assets;
- future well performance and related well economics;
- expectations regarding the renewal of our Credit Facility;
- projections of market prices and costs and exchange and inflation rates;
- our capital expenditure program, the timing of expenditures and the sources of funding;
- anticipated benefits under forward contracts;
- our access to credit facilities, ability to raise capital and financial flexibility;
- future commodity prices;
- supply and demand for oil, natural gas and NGLs;
- expected royalty rates and the anticipated benefits of royalty incentive programs;
- treatment under governmental regulatory regimes and tax laws;
- impact of international events and agreements on Canadian producers;
- impact of federal and provincial legislative and regulatory changes on the oil and gas industry;

- the anticipated impact of the factors and our plans discussed under the heading "*Industry Conditions*" and "*Risk Factors*" on us; and
- our assessment of the impact of the various risks identified under the heading "*Risk Factors*".

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- the uncertainties in regard to the timing and results of our exploration and development program, including SAGD developments;
- impacts of pandemics;
- our ability to market our oil, natural gas and NGLs;
- effects of tariffs on materials, goods, and the realized pricing for our production;
- market prices of oil, natural gas and NGLs;
- exploration, development and production risks;
- operational risks and liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- changes in capital allocation decisions;
- the occurrence of unexpected events;
- inflation and cost management;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- access to a skilled workforce;
- water and CO_2 supplies;
- effects of inflation;
- stock market volatility;
- risks relating to our Credit Facility;
- restrictions on our ability to pay dividends and the impact of changes to our dividend policy;
- political or economic developments;
- changes in general economic, market and business conditions;
- the impact of negative public and investor sentiment;
- incorrect assessments of the value of acquisitions;
- risks associated with various projects;
- operational dependence on others and third party risks;
- the impact of our risk management activities;
- ability to obtain regulatory and other third party approvals;
- uncertainties and changes in royalty regimes and other regulatory changes;
- environmental and climate change risks;
- fluctuations in foreign exchange or interest rates;
- the inability to access capital from internal and external sources;
- fluctuations in the availability and costs of borrowing;
- our title to and rights to produce from our assets;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing and cost of our exploration and development program;
- the uncertainties in regard to abandonment and reclamation liabilities and costs;
- the availability and cost of insurance;

- costs of new technologies;
- fluctuation in the supply and demand for oil and natural gas;
- future dilution;
- management of growth;
- expiration of leases or licences;
- the results of litigation or regulatory proceedings that may be brought against us;
- uncertainty regarding the impact of legal developments pertaining to Indigenous rights and treaty claims;
- impacts of the Russian Ukrainian conflict, the Israel Hamas conflict and related actions;
- changes in income tax laws or changes in tax laws, including carbon taxes, and incentive programs relating to the oil and gas industry;
- seasonality;
- diluent supply;
- exposure to third party credit risks;
- potential conflicts;
- uncertainties in new continuous disclosure obligations;
- information technology and cyber-security issues;
- risks associated with expanded activities;
- drought and flooding;
- fluid disposal;
- potential opposition from non-governmental organizations;
- reputational risks associated with our operations; and
- the other factors discussed under "*Risk Factors*".

In addition to other factors and assumptions set forth above, assumptions have also been made regarding the potential impact tariffs that may be implemented by the U.S. and Canadian governments, and that neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas.

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; differentials; the impact of increasing competition; conditions in general economic and financial markets; access to capital; uninterrupted access to infrastructure; forecasts with respect to reserves volumes; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating and other costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this

Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

OIL AND GAS ADVISORY

In accordance with NI 51-101, natural gas volumes have been converted to barrels of oil equivalent using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. This 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. The term "boe" is useful for comparative measures and observing trends, it does not accurately reflect individual product value and may be misleading, particularly if used in isolation. Based on the current price of crude oil to natural gas, using a 6:1 conversion ratio may be misleading as an indication of value.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this document and in other materials disclosed by us, we adhere to International Accounting Standards Board's most current International Financial Reporting Standards ("**IFRS**" or "**GAAP**"), however we also employ certain non-GAAP and other financial measures to analyze financial performance, financial position, and cash flow including, but not limited to "netbacks". These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures used herein should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as earnings (loss), cash flow from operating activities, and cash flow used in investing activities, as indicators of our performance. The most directly comparable GAAP measure for netback is gross sales price. Refer to the section entitled "*Non-IFRS and Other Financial Measures*" contained within our MD&A for the year ended December 31, 2024, available on SEDAR+ at *www.sedarplus.ca*, for additional disclosures relating to these non-GAAP measures, which information is incorporated in this Annual Information Form by reference.

CARDINAL ENERGY LTD.

We were incorporated under the *Business Corporations Act* (Alberta) as 1577088 Alberta Ltd. on December 21, 2010. On May 25, 2012, we changed our name to "Cardinal Energy Ltd.". On June 28, 2012, we amended our articles ("**Articles**") to change the rights, privileges, restrictions and conditions in respect of our Common Shares, including enabling us to issue stock dividends declared on our Common Shares. On July 27, 2012, we amended our Articles to remove our private company restrictions. On September 9, 2013, we amended our Articles to consolidate our Common Shares on a three for one basis and to amend the percentage of the average market price used when calculating a stock dividend on our Common Shares. See "*Description of our Capital Structure – Share Capital – Common Shares*".

We currently do not have any subsidiaries. During the year ended December 31, 2015, we completed a number of vertical amalgamations with our then wholly owned subsidiaries and on January 1, 2022, Venturion was amalgamated into us.

Our head office is located at Suite 600, 400 – 3rd Avenue S.W., Calgary, Alberta T2P 4H2 and our registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

We are a Canadian oil and natural gas company with operations focused on low decline oil in Western Canada. We differentiate ourselves from our peers by having one of the lowest decline conventional asset base in Western Canada. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

We commenced operations in May of 2012 and then on December 17, 2013, we completed an acquisition of assets located in Southeast Alberta, closed our initial public offering and our Common Shares commenced trading on the Toronto Stock Exchange. The following is a summary of the development of our business over the last three years.

Developments in 2022

On March 14, 2022, we announced that our Board of Directors had approved an increase to our 2022 $90 million capital and ARO budget of $15 million which included approximately $5 million for strategic land acquisitions and $10 million for additional ARO expenditures.

On March 31, 2022, we prepaid our 2021 Secured Notes which were issued on July 14, 2021 for a payment of $13.7 million which included the principal amount, $0.9 million of accrued interest and a pre-payment fee of $0.3 million.

Effective May 9, 2022, we renewed our Credit Facility with a syndicate of lenders. Consistent with our strategy of reducing our overall corporate debt levels and to reduce additional fees, we reduced the size of our Credit Facility from $225 million to $185 million. In the fourth quarter of 2022, we elected to further reduce our Credit Facility to $155 million to reduce standby fees.

We carefully monitor the impact of all issues affecting our business and the necessity to adjust our monthly dividends and our capital programs as conditions evolve and on March 17, 2020, we suspended our dividend due to the economic environment. On May 12, 2022, we announced that our Board of Directors had approved the reinstatement of our monthly dividend starting at $0.05 per Common Share per month in June 2022.

On June 13, 2022, we announced that all outstanding 2020 Warrants and 2021 Warrants had been exercised. The proceeds were used to reduce our outstanding debt, further supporting our net debt reduction strategy. There are no remaining 2020 Warrants or 2021 Warrants outstanding.

On June 27, 2022, we announced that the Toronto Stock Exchange had accepted our intention to commence a normal course issuer bid ("**2022 NCIB**"). Pursuant to the 2022 NCIB, we were permitted to purchase up to 12,319,686 Common Shares representing approximately 10% of our public float as of June 20, 2022 over a twelve month period commencing June 30, 2022. We repurchased and cancelled 3,724,156 Common Shares at an average price of $7.05 per Common Share, for a total cost of $26.3 million under the 2022 NCIB.

On July 28, 2022, we announced that our Board of Directors had approved a $30 million increase to our 2022 capital budget to take advantage of opportunities and to account for inflationary pressures on our existing capital budget.

On September 12, 2022, we announced that our Board of Directors had approved an increase in our monthly dividend commencing in the fourth quarter of 2022 from $0.05 per Common Share to $0.06 per Common Share.

On November 8, 2022, we announced that our Board of Directors had approved our 2023 capital budget of $97 million and an additional investment of $23 million for ARO.

Developments in 2023

During the second quarter of 2023, we acquired certain exploration and evaluation ("**E&E"**) assets in Saskatchewan for total consideration of $10.0 million, with associated decommissioning obligations of $0.2 million, from Broadview Energy through the issuance of 1,362,397 Common Shares valued at $7.35 per Common Share.

Effective May 11, 2023, we amended and restated our Credit Facility to, among other things, extend the revolving date and maturity date of the Credit Facility to May 31, 2023 and May 31, 2024, respectively.

On June 8, 2023, we announced that we had released our 2022 ESG Report, which outlined our commitment to operate in a responsible and sustainable manner, setting out our initiatives and outlining our progress in providing sustainable production, positive environmental performance and top tier shareholder returns.

On June 28, 2023, we announced that the Toronto Stock Exchange had accepted our intention to renew our 2022 NCIB (the "**2023 NCIB**"). Pursuant to the 2023 NCIB, we were permitted to purchase up to 12,062,372 Common Shares representing approximately 10% of our public float as of June 16, 2023 over a twelve-month period commencing on June 30, 2023. We did not purchase any Common Shares under the 2023 NCIB.

On October 3, 2023, we closed an asset acquisition to acquire certain petroleum and natural gas properties including assets within our core operating area of Mitsue. Total consideration was $24.6 million, before closing adjustments.

During 2023, we completed various property acquisitions for total consideration of $4.8 million after closing adjustments with associated decommissioning obligations of $1.4 million.

In 2023, we also disposed of non-core assets for total cash proceeds of $11.6 million with associated decommissioning obligations of $9.1 million.

On November 6, 2023, we announced that with additional lands acquired at land sales together with the E&E assets acquired from Broadview Energy in the second quarter of 2023, we had identified up to three SAGD projects in Saskatchewan that may be commercially developed. Some of the attributes of developing and producing oil through SAGD technology in Saskatchewan include: (i) smaller pool size of 6,000-20,000 bopd which are more risk appropriate for Cardinal; (ii) known "off the shelf" proven SAGD technology available at fixed pricing giving better certainty around project economics; (iii) large talent pool of professionals with previous development and production experience available; (iv) supportive provincial regulatory environment; (v) year round land access on paved roads within existing utility infrastructure; (vi) multiple access points for product sales including third party sales points, Cardinal owned facilities and rail options; (vii) established water source with no use of surface water in the development of these projects; (viii) natural gas power generation on site eliminates exposure to fluctuating electrical prices; (ix) we have nearly 1,000,000 tonnes of potential and verified CO_2 emissions reductions in Saskatchewan from our CO_2 sequestration project to offset future greenhouse gas emissions associated with the SAGD operation; and (x) low operating costs which may lower our overall operating cost structure in the future.

We have identified properties in the Reford area of Saskatchewan as our first thermal oil project for development using SAGD technology which, when completed, is expected to be a 6,000 bbl/d (100% heavy crude oil) SAGD facility.

On November 6, 2023, we also announced that our Board of Directors had approved our 2024 conventional capital budget of $116 million, with a further $68.5 million for the Reford Project and an additional investment of $20 million for ARO.

On November 6, 2023, we also announced the retirement of Mr. David Johnson from our Board of Directors and the appointment of Mr. John Festival to our Board of Directors.

Developments in 2024

On February 12, 2024, we announced that we had entered into an agreement with Propak for the engineering, fabrication and field construction of the central processing facility, including the first SAGD well pad at our Reford Project. The fixed-price agreement with Propak, which represents approximately half of the total estimated project cost, is expected to provide cost certainty for us, in addition to reducing manufacturing uncertainty as a result of Propak's ability to manufacture and fabricate the modular facilities in a controlled indoor environment.

On May 8, 2024, we announced we had updated our 2024 capital budget as a result of strong first quarter 2024 drilling results, by reducing our drilling and completions development capital budget and our ARO budget by a total of $26 million.

On May 27, 2024, we announced an increase in our Credit Facility from $155 million to $200 million to provide additional support for our capital program, including our Reford Project and extended the revolving period and maturity date to May 31, 2025 and May 31, 2026, respectively. In connection with the renewal, we also received a reserve based lending commitment from a new lender, Business Development Bank of Canada.

On September 10, 2024, we announced that we had again been included in the Toronto Stock Exchange's 2024 TSX30™, a flagship program recognizing the 30 top performing Toronto Stock Exchange stocks over a three-year period based on dividend-adjusted share price appreciation. For the three years ended June 30, 2024, we achieved remarkable returns for Shareholders, with a 134% increase in dividend-adjusted share price performance and a 111% increase in market capitalization over the same period.

On December 12, 2024, we announced that we had entered into an agreement with our syndicate of lenders to redetermine and increase our Credit Facility. The Credit Facility was increased to $275 million (previously $200 million) while the revolving period and maturity date remained the same at May 31, 2025 and May 31, 2026, respectively. See "*Description of our Capital Structure – Credit Facility*".

On December 18, 2024, we announced that we had entered into an agreement with a syndicate of underwriters pursuant to which the underwriters agreed to purchase for resale to the public, on a bought deal basis, 50,000 Units for gross proceeds of approximately $50 million. We also granted the underwriters an option (the "**Underwriters' Option**") to purchase up to an additional $10 million of Units pursuant to the Unit Offering, such option to be exercised in whole or in part at the sole discretion of the underwriters, at any time until two business days prior to the closing date of the Unit Offering.

Recent Developments

The Unit Offering closed on January 3, 2025. The net proceeds of the Unit Offering (including the proceeds from the Underwriters' Option which was exercised in full) was used to initially repay outstanding indebtedness under the Credit Facility which may be subsequently redrawn and used to further the completion of the Reford Project, accelerate the development of future thermal projects and for general corporate purposes.

On January 15, 2025, we announced that our Board of Directors had approved a conventional capital budget of $71 million and a thermal oil budget of $120 million to complete the Reford Project and to de-risk our second thermal project at Kelfield.

On February 24, 2025, we announced that we had entered into an agreement with a syndicate of underwriters pursuant to which the underwriters agreed to purchase for resale to the public, on a bought deal basis, $40 million aggregate principal amount of Second Series Debentures for gross proceeds of approximately $40 million. We also granted the underwriters an option (the "**2025 Underwriters' Option**") to purchase up to an additional $5 million aggregate principal amount of Second Series Debentures, such option to be exercised in whole or in part at the sole discretion of the underwriters, at any time until two business days prior to the closing date of the Debenture Offering.

The Debenture Offering closed on March 4, 2025. The net proceeds of the Debenture Offering (including the proceeds from the 2025 Underwriters' Option which was exercised in full) was used to initially repay outstanding indebtedness under the Credit Facility which may be subsequently redrawn and used to to de-risk the completion of the Reford Project, to accelerate the de-risking of our Kelfield thermal oil opportunity and for land and seismic acquisitions to delineate other thermal oil opportunities available to us. In connection with the Debenture Offering, we also amended our Credit Facility to increase the amount of permitted subordinated debt.

Significant Acquisitions

We have not completed any significant acquisitions during our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

We are a Canadian company focused on low decline light, medium and heavy quality oil production in Western Canada. Our objective is to build core operating areas with sufficient scale of production as well as organic and acquisition growth prospects to achieve operational cost and production efficiency in each core area. We manage exploration, production and marketing risks through the expertise of our experienced technical and management personnel.

Specialized Skill and Knowledge

We employ individuals with various professional skills in the course of pursuing our business plan. In addition, specialized consultants are available to assist us in areas where we feel we don't need full-time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are widely available in the industry. Drawing on significant experience in the oil and natural gas business, we believe our management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: (i) strong technical skills; (ii) expertise in planning and financial controls; (iii) ability to execute on business development opportunities; (iv) capital markets expertise; and (v) an entrepreneurial spirit that allows us to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

The oil and natural gas industry is intensely competitive and we are required to compete with a substantial number of other entities which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, access to new prospects is becoming more and more competitive and complex. We believe that we have a strong competitive position in the areas in which we operate, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

We attempt to enhance our competitive position by operating in areas where we believe our technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. We believe that we will be able to explore for and develop new production and reserves with the objective of increasing our cash flow from operating activities and reserve base. See "*Risk Factors – Competition*", "*Risk Factors – Availability of Supplies for EOR Schemes*" and "*Risk Factors – Inflation, Interest Rates and Cost Management*".

Cycles

Our business is generally not cyclical. However, our operational results and financial condition are dependent on prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years. Oil and natural gas prices are determined by a number of factors, including global and local supply and demand factors, egress options, weather, general economic conditions as well as conditions in other oil and natural gas producing and consuming regions. See "*Risk Factors – Prices, Markets and Marketing*".

In addition, the exploration for and the development of crude oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variations, including "freeze up" and "break up", affect access in certain circumstances. Consequently, during periods when weather which makes the ground unstable, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. See "*Risk Factors – Seasonality*".

Employees

As at December 31, 2024, we had 69 full-time employees located at our head office and 110 full-time employees located in the field.

Environmental, Health and Safety Policies

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on our earnings and our overall competitiveness. For a description of the financial and operational effects of environmental protection requirements on our capital expenditures, earnings and competitive position, see: "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors*".

We strive for an injury-free workplace for our employees and contractors, and we promote a safety culture through systems, processes and continued learning to mitigate risks. Safety is a core element across our organization and is kept top-of-mind in everything we do.

Our approach to maintaining safe and reliable operations starts with our executive team and is embodied by rigorous health and safety programs with ongoing process and occupational safety improvements. We continuously plan and practice effective responses to unlikely incidents, always prioritizing worker and community safety as well as environmental protection.

We promote safety and environmental awareness and protection through the implementation and communication of our environmental management and employee occupational health and safety programs, policies and procedures. Committee structures are established in our operations which are designed to allow for employee participation and development of policies and programs which provide employees with job orientation, training, instruction and supervision to assist them in conducting their activities in an environmentally responsible and safe manner.

Our safety record is in the top tier of the industry as is our regulatory compliance approval level.

Our teams develop integrated emergency response preparedness plans between our Calgary staff, staff in our various operating areas, and in conjunction with local authorities, emergency services and local communities. These measures are in place to allow us to effectively respond to an environmental or safety-related incident, should it arise. These plans are reinforced with live exercises in the field and corporately. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. We conduct audits of our operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist us in achieving the objectives of the described policies and programs.

We also face environmental, health and safety risks in the normal course of our operations due to the handling and storage of hazardous substances. Our environmental and occupational health and safety management systems are designed to manage such risks in our business and allow action to be taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key component of these systems is the undertaking of frequent environmental and safety audits.

We remain focused on creating, enhancing and delivering value to our Shareholders. One way we seek to protect value is by better understanding, disclosing and managing our environmental and social impacts. In recognition of the importance of clear Board oversight and risk management for ESG matters, we have established a separate ESG Committee of our Board.

In 2024, through our carbon capture and sequestration ("**CCS**") EOR operation at Midale, we sequestered approximately 181,000 tonnes of CO_2 in 2024. To date, the Midale Unit has sequestered 5.8 million tonnes of CO_2 and reduced oil production decline rates to approximately 3% to 5%.

In 2024, Cardinal continued with a focus on closure of inactive assets, including abandonment of wells, pipelines and facilities, as well as surface reclamation of abandoned sites. During the year, Cardinal abandoned over 55 wells, 128 kilometers of pipeline and one facility. We also received 55 reclamation certificates and exceeded all regulatory requirements for spending allocations on inactive liabilities. We strive to minimize our surface footprint with multi-well pads, horizontal wells, and advanced drilling technology, while increasing the resource accessed, thereby being more efficient with our surface disturbance.

We continue to value our relationships with the various First Nations living in and around our areas of operation, particularly in northern Alberta, a core area of our production. Through our operations, we have been exposed to the challenges of individuals living in remote areas and strongly believe that we, as a community partner, have a role to play.

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against Cardinal, or any voluntary bankruptcy, receivership or similar proceedings by Cardinal within the three most recently completed financial years or during or proposed for the current financial year.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated February 21, 2025. The statement is effective as of December 31, 2024. Reserve evaluations have not been updated since the effective date and therefore do not reflect changes in our reserves since that date. The preparation date of the Statement of Reserves Data and Other Oil and Gas Information outlined below is March 26, 2025. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 are attached as Appendices A and B, respectively, to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon the evaluations by GLJ and McDaniel with an effective date of December 31, 2024 as contained in the GLJ Report and the McDaniel Report, which are contained in the Consolidated Reserve Report prepared by GLJ. The Consolidated Reserve Report evaluates, as at December 31, 2024, all of our crude oil, NGL and natural gas reserves. McDaniel evaluated all of our reserves at the Reford Project, which represent approximately 18% of the total proved plus probable future net revenue discounted at 10% recognized in the Consolidated Reserve Report. Consistent with prior years, GLJ evaluated the balance of our properties, in the GLJ Report, which represent approximately 82% of the total proved plus probable future net revenue discounted at 10% recognized in the Consolidated Reserve Report. GLJ prepared the Consolidated Reserve Report by consolidating the

GLJ Report with the McDaniel Report. The Consolidated Reserve Report varies from a simple arithmetic summation of the GLJ Report and the McDaniel Reserve Report due to software calculation rounding. McDaniel and GLJ incorporated the forecast price and cost assumptions as described below under the heading "*Pricing Assumptions*" in their evaluations.

The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present value of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The GLJ Report and the McDaniel Report have been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324.

We determined the future net revenue and net present value of future net revenue after income taxes by utilizing the before income tax future net revenue from the Consolidated Reserve Report and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of our value as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2024 should be consulted for additional information regarding our future income taxes.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs arising from the anticipated development and production of resources, net of associated royalties, operating costs, development costs and abandonment and reclamation costs. Abandonment and reclamation costs included in the Consolidated Reserve Report are the costs to abandon and reclaim all company working interest wells, pipelines and facilities whether or not reserves have been assigned.

The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Consolidated Reserve Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

	SUMMARY OF OIL AND NATURAL GAS RESERVES (1) AS OF DECEMBER 31, 2024 FORECAST PRICES AND COSTS							
	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS (2)		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	44,132	37,340	24,272	20,755	40,122	35,960	2,661	2,236
Developed Non-Producing	767	681	298	232	2,321	1,984	45	39
Undeveloped	5,732	5,023	1,640	1,360	6,405	5,696	236	206
TOTAL PROVED	50,631	43,045	26,209	22,346	48,847	43,640	2,942	2,481
TOTAL PROBABLE	16,407	13,536	46,520	38,511	14,712	12,958	903	745
TOTAL PROVED PLUS PROBABLE	67,038	56,581	72,729	60,857	63,560	56,598	3,846	3,226

Notes:

(1) Total values may not add due to rounding.
(2) Includes solution gas.

RESERVES CATEGORY	SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2024 BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR) 0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/ YEAR $/Boe [(1)]
PROVED:						
Developed Producing	2,516	1,832	1,405	1,146	975	21.19
Developed Non-Producing [(2)]	(163)	(67)	(36)	(23)	(17)	(28.13)
Undeveloped	327	226	166	127	100	22.07
TOTAL PROVED	2,679	1,991	1,536	1,250	1,059	20.44
TOTAL PROBABLE	2,525	1,327	824	564	411	14.99
TOTAL PROVED PLUS PROBABLE	5,205	3,318	2,359	1,814	1,470	18.14

Notes:

(1) Based on net reserves.

(2) Includes all abandonment, decommissioning and reclamation ("**ADR**") costs, active (included in the proved developed producing category) and inactive (included in the proved developed non-producing ("**PDNP**") category). The before tax net present value of PDNP excluding ADR would be $27.8 million.

RESERVES CATEGORY	SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2024 AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
PROVED:					
Developed Producing	2,093	1,590	1,246	1,033	890
Developed Non-Producing	(127)	(51)	(28)	(18)	(14)
Undeveloped	248	169	122	92	72
TOTAL PROVED	2,214	1,708	1,341	1,107	948
TOTAL PROBABLE	1,902	980	601	407	293
TOTAL PROVED PLUS PROBABLE	4,116	2,687	1,941	1,513	1,240

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2024 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE[(1)] ($MM)	ROYALTIES[(2)] ($MM)	OPERATING COSTS ($MM)	DEVELOP-MENT COSTS ($MM)	ABANDON-MENT AND RECLAMATI-ON COSTS [(3)] ($MM)	FUTURE NET REVENUE BEFORE FUTURE INCOME TAX EXPENSES ($MM)	FUTURE INCOME TAX EXPENSES ($MM)	FUTURE NET REVENUE AFTER FUTURE INCOME TAX EXPENSES ($MM)
TOTAL PROVED	8,584	1,415	3,543	199	747	2,679	466	2,214
TOTAL PROVED PLUS PROBABLE	15,081	2,642	5,683	779	773	5,205	1,089	4,116

Notes:

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

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

(3) Represents ADR costs to abandon and reclaim all company working interest wells, pipelines and facilities whether or not reserves have been assigned. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*".

PRODUCT TYPE	FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2024 FORECAST PRICES AND COSTS FUTURE NET REVENUE BEFORE INCOME TAXES [(1)] (discounted at 10%/year) ($MM)	UNIT VALUE [(2)] ($/Boe)
TOTAL PROVED:		
Light and Medium Crude Oil [(3)]	1,052	20.94
Heavy Crude Oil [(3)]	475	20.68
Conventional Natural Gas [(4)]	8	4.35
	1,536	20.44
TOTAL PROVED PLUS PROBABLE		
Light and Medium Crude Oil [(3)]	1,338	20.31
Heavy Crude Oil [(3)]	1,012	16.36
Conventional Natural Gas [(4)]	10	4.05
	2,359	18.14

Notes:

(1) Other company revenue and costs not related to a specific product type have been allocated proportionately to product types listed.
(2) Unit values are based on net reserves.
(3) Including solution gas and other by-products.
(4) Including by-products but excluding solution gas.

Definitions and Notes to Reserves Data Tables

In the tables set forth above and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. **gross** means:

   (a) in relation to our interest in production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. **net** means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

Reserve Categories

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

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions (see the discussion of "economic assumptions" below).

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

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

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

4. **economic assumptions** are the forecast prices and costs used in the estimate.

Development and Production Status

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 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

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

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.

5. **exploratory well** means a well that is not a development well, a service well or a stratigraphic test well.

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

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly 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.

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

9. **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, carbon dioxide or fuel gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

10. forecast prices and costs

These are prices and costs that are:

(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 we are 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).

11. Numbers may not add due to rounding.

12. We do not have any synthetic oil or other products from non-conventional oil and gas activities.

Pricing Assumptions

The forecast cost and price assumptions in this Annual Information Form assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

The forecast of prices, inflation and exchange rates provided in the table below were computed using the average of the forecasts ("**IQRE Average Forecast**") by McDaniel, GLJ and Sproule Petroleum Consultants, The IQRE Average Forecast is dated January 1, 2025. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs.

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Consolidated Reserve Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2024

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS			
YEAR	WTI CUSHING OKLAHOMA ($US/Bbl)	CANADIAN LIGHT SWEET 40° API ($/Bbl)	WESTERN CANADA SELECT 20.5 API ($/Bbl)	CROMER MEDIUM 29° API ($/Bbl)	AECO GAS PRICE ($/MMbtu)	EDMONTON PROPANE ($/Bbl)	EDMONTON BUTANE ($/Bbl)	INFLATION RATES %/Year (1)	EXCHANGE RATE ($/$US) (2)
Forecast									
2025	71.58	94.79	82.69	91.30	2.36	33.56	51.15	0.00	0.712
2026	74.48	97.04	84.27	93.48	3.33	32.78	49.98	2.00	0.728
2027	75.81	97.37	83.81	93.79	3.48	32.81	50.16	2.00	0.743
2028	77.66	99.80	85.70	96.14	3.69	33.63	51.41	2.00	0.743
2029	79.22	101.79	87.46	98.05	3.76	34.30	52.44	2.00	0.743
2030	80.80	103.83	89.25	100.02	3.83	34.99	53.49	2.00	0.743
2031	82.42	105.91	91.04	102.02	3.91	35.69	54.56	2.00	0.743
2032	84.06	108.02	92.85	104.06	3.99	36.40	55.65	2.00	0.743
2033	85.75	110.19	94.71	106.14	4.07	37.13	56.76	2.00	0.743
2034	87.46	112.39	96.61	108.26	4.15	37.87	57.90	2.00	0.743
2035	89.21	114.64	98.54	110.43	4.24	38.63	59.05	2.00	0.743
2036	90.99	116.93	100.51	112.64	4.32	39.40	60.24	2.00	0.743
2037	92.82	119.27	102.52	114.89	4.41	40.19	61.44	2.00	0.743
2038	94.67	121.65	104.57	117.19	4.49	41.00	62.67	2.00	0.743
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.743

Notes:

(1) Inflation rate for operating and capital costs.
(2) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices we realized for the year ended December 31, 2024, excluding price risk management activities, were $90.80/Bbl for light and medium crude oil, $79.39/Bbl for heavy crude oil, $1.61/Mcf for natural gas and $37.23/Bbl for NGLs.

Reserves Reconciliation

The following table sets forth the reconciliation of our gross reserves as at December 31, 2024, using forecast price and cost estimates derived from the Consolidated Reserve Report.

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL[(2)]			HEAVY CRUDE OIL		
	GROSS PROVED (Mbbls)	GROSS PROBABLE (Mbbls)	GROSS PROVED PLUS PROBABLE (Mbbls)	GROSS PROVED (Mbbls)	GROSS PROBABLE (Mbbls)	GROSS PROVED PLUS PROBABLE (Mbbls)
December 31, 2023	**51,189**	**16,961**	**68,151**	**25,840**	**8,766**	**34,606**
Discoveries [(1)]	-	-	-	-	38,181	38,181
Extensions and Improved Recovery [(2)]	667	235	901	1,524	36	1,560
Technical Revisions [(3)]	2,552	(763)	1,789	1,858	(465)	1,393
Acquisitions [(4)]	-	-	-	-	-	-
Dispositions [(4)]	-	-	-	-	-	-
Economic Factors [(5)]	28	(27)	1	2	1	4
Production	(3,805)	-	(3,805)	(3,015)	-	(3,015)
December 31, 2024	**50,631**	**16,407**	**67,038**	**26,209**	**46,520**	**72,729**

	CONVENTIONAL NATURAL GAS			NATURAL GAS LIQUIDS		
	GROSS PROVED (MMcf)	GROSS PROBABLE (MMcf)	GROSS PROVED PLUS PROBABLE (MMcf)	GROSS PROVED (Mbbls)	GROSS PROBABLE (Mbbls)	GROSS PROVED PLUS PROBABLE (Mbbls)
December 31, 2023	**51,256**	**19,331**	**70,588**	**2,937**	**1,139**	**4,076**
Discoveries [(1)]	-	-	-	-	-	-
Extensions and Improved Recovery [(2)]	1,615	55	1,669	33	7	41
Technical Revisions [(3)]	996	(4,676)	(3,680)	271	(244)	26
Acquisitions [(4)]	-	-	-	-	-	-
Dispositions [(4)]	-	-	-	-	-	-
Economic Factors [(5)]	14	4	18	3	1	3
Production	(5,035)	-	(5,035)	(301)	0	(301)
December 31, 2024	**48,847**	**14,712**	**63,560**	**2,942**	**903**	**3,846**

Notes:

(1) Discoveries include the reserves additions at our Reford Project.

(2) Includes the expansion or increased recovery factor for existing reservoirs as a result of additional step-out drilling, infill drilling or enhanced oil recovery.

(3) Technical revisions are due to changes in previously booked estimates. In 2024, these revisions were: (i) positive light and medium crude oil included revisions in the Bantry Oil, Killam North, Mica, Mitsue and Midale areas; (ii) positive heavy crude oil reserves included revisions in the Clearwater, Viking Kinsella and Wainwright West areas; (iii) negative natural gas reserves were due to lower gas pricing; and (iv) positive natural gas liquids included reserve revisions in the Bantry Oil, House Mountain and Mica areas due to higher liquids recovery.

(4) There were no reserves acquisitions and dispositions in 2024.

(5) The economic factors amount is the change in reserves due to changes in product pricing.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ and McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (such as pricing, royalty structure, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water or steam breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals); and (vi) for thermal operations, the availability of gas/power source; water source for steam generation; regulatory scheme approvals; and environmental approvals. For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years.

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		HEAVY CRUDE OIL (Mbbls)		CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2022	170	4,650	-	1,178	29	1,795	-	191
2023	1,139	5,162	1,955	2,597	2,418	7,795	33	340
2024	634	5,732	475	1,640	655	6,405	22	236

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool.

GLJ has assigned 8.7 MMBoe of proved undeveloped reserves in the Consolidated Reserve Report with $127 million of associated undiscounted capital, of which $54 million is forecast to be spent in the first two years. A total of $105 million of associated undiscounted capital is forecast to be spent in the first four years. The majority of the capital forecast after four years is associated with future development and CO_2 purchases for the enhanced recovery project in our Midale property. This is consistent with the long-term development nature of CO_2 EOR projects. Development of other properties scheduled beyond two years is associated with properties which are being exploited at a controlled pace. The pace of development could be accelerated from that scheduled and is typically dependent on capital allocation.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years.

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		HEAVY CRUDE OIL (Mbbls)		CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2022	284	3,702	-	1,715	49	1,664	-	107
2023	334	3,439	1,744	2,768	1,134	3,554	14	180
2024	228	4,261	38,490	40,012	274	2,322	9	109

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool.

GLJ and McDaniel have assigned 44.8 MMBoe of probable undeveloped reserves in the Consolidated Reserve Report with $574 million of associated undiscounted capital, of which $168 million is forecast to be spent in the first four years. Any capital forecast after four years is associated with future development, CO_2 purchases for the EOR project in our Midale property, and SAGD wells and central plant facilities maintenance in our Reford Project. This is consistent with the long-term development nature of CO_2 EOR and thermal projects.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in future commodity prices relative to the forecasts provided under the heading "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above, we expect to fund the development costs of our reserves through a combination of internally generated cash flow from operating activities, debt and equity issuances. There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Consolidated Reserve Report. Failure to develop those reserves could have a negative impact on our future cash flow from operating activities. Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

In connection with our operations, we will incur abandonment and reclamation costs for wells, facilities, pipelines and surface leases.

Our model for estimating the amount of future abandonment and reclamation expenditures is done on an individual well and facility level. Each well and facility is assigned a cost for abandonment and reclamation over its useful life. Timing of expenditures takes into account seasonal access, priority and stakeholder issues, and opportunities for multi-location programs to reduce costs. Facility reclamation costs are generally scheduled to begin at the end of the reserve life of our associated reserves and continue beyond the reserve life under the assumption that plant/facilities are generally mobile assets with a long useful life. No estimate of salvage value is netted against the estimated cost.

The Consolidated Reserve Report deducted $741 million undiscounted (and inflated by two percent) and $90 million discounted at 10% for the costs to abandon and reclaim all company working interest wells, pipelines and facilities whether or not reserves have been assigned from the estimates of the future net revenue disclosed in this Annual Information Form. An additional $32 million undiscounted (and inflated by two percent) was deducted for the total proved plus probable undeveloped locations assigned reserves.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below using forecast prices and costs.

	FORECAST PRICES AND COSTS	
YEAR	PROVED RESERVES (1) ($MM)	PROVED PLUS PROBABLE RESERVES (1)(2) ($MM)
2025	17	120
2026	51	69
2027	41	63
2028	20	44
2029	18	31
Remaining	52	451
Total (Undiscounted)	199	779
Discounted (10%)	140	414

Notes:

(1) Includes $40 million and $51 million associated with proved and proved plus probable reserves respectively, for the purchase of CO_2 for the EOR schemes in the Midale area.

(2) Includes the total of $535 million associated with proved plus probable reserves, for the thermal central plant facilities, central plant facilities maintenance, and drilling of the SAGD well pairs in our Reford Project.

We ordinarily expect to fund the development costs of our reserves through a combination of internally generated cash flow from operating activities, debt and equity issuances.

There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Consolidated Reserve Report. Failure to develop those reserves could have a negative impact on our future cash flow from operating activities.

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2024. Information in respect of current production is average production, net to our working interest, except where otherwise indicated. We operate approximately 99% of our production. Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The production in this section is shown on a boe basis. See the *Production History* section below for disaggregated production.

Southern Alberta, Bantry, Area

The Bantry assets, which includes the Tide Lake, Alderson, Duchess, Rosemary and Kininvie areas, are located near Brooks, Alberta. Bantry's average 2024 production was approximately 5,453 Boe/d (40% light and medium crude oil, 40% heavy oil, 18% conventional natural gas and 2% NGLs). The majority of our oil in this area is pipeline-connected to Cardinal-operated facilities, and is sales line connected to the Bow River South oil transmission system. Most of the produced natural gas is conserved and sold through these Cardinal facilities, or third-party facilities.

The majority of our crude oil production is from the Upper Mannville Glauconitic and Lower Mannville Ellerslie formations. Dominantly fluvial in nature, lower Mannville Ellerslie strata accumulated within valleys overlying the pre-Cretaceous unconformity in the Bantry area. Generally hydrocarbon charged, reservoir quality varies materially throughout the area. Oil accumulations are typically trapped stratigraphically by shale and tight siltstones. Current activity is focused on expanding known pool areas through horizontal drilling.

Upper Mannville Glauconite incised channels in the Bantry area are typically lithic in composition and transport erosional sediments from southerly highlands to the Clearwater sea to the north. Generally hydrocarbon charged, these channels are identified through a combination of existing vertical well control and 3D seismic data. Current development is focused on extending and infilling existing known channel trends.

The majority of these producing oil reservoirs are under enhanced recovery in the form of waterflood. We have identified areas where we can optimize existing waterfloods to further enhance oil recoveries. Optimization of these waterfloods, to further enhance oil recovery, is continually underway.

In 2024, we continued our drilling program in Bantry, drilling 6 (6.0 net) multi-leg Ellerslie horizontal wells. We currently plan to drill 2 (2.0 net) additional wells in our Bantry area during 2025.

Northern Alberta, Mitsue Area

Our Mitsue property is located approximately 250 kilometers north of Edmonton, Alberta. Average 2024 production for this property was 3,970 Boe/d (46% light and medium crude oil, 37% heavy oil, 4% NGLs and 13% conventional natural gas) with a low decline production profile. The majority of the production is from the Mitsue Gilwood Sand Units. Wells are pipeline-connected to oil battery sites and a main gas plant where the oil and natural gas are connected to sales pipelines. We operate the wells and facilities within the Mitsue Gilwood Sand Units.

The Mitsue Gilwood A Pool was discovered in 1964 and produces 40° API oil from the Gilwood sandstone of the Middle Devonian Watt Mountain formation. Mitsue oil is trapped at the up-dip depositional edge in high quality deltaic sandstones of the Gilwood member. The reservoir is approximately 120,000 acres in size, one of the largest sandstone reservoirs in Canada and it is drilled to a density of less than one well per quarter section. Future opportunities include both vertical and horizontal infill drilling, and ongoing optimization of the existing waterflood.

Additionally, recent activity north of the Mitsue unit, at our Nipisi project began in 2022. This development is focused on oil targets in Mannville aged, regional marine sands of the Clearwater formation. Development targeting stratigraphically trapped 18-20° API heavy oil, using open-hole horizontal multilateral drilling is ongoing, with long-term waterflood optimization being assessed.

During 2024, we drilled 3 (3.0 net) operated wells on the Nipisi lands.

Northern Alberta, House Mountain, Area

House Mountain is located approximately 70 kilometers to the southwest of our Mitsue field and approximately 230 kilometers north of Edmonton. The property includes an average 87% operated interest in four light oil producing units as well as a 100% interest in various non-unit lands.

The House Mountain property initially discovered in 1963 is developed with vertical and horizontal wells producing 41° API oil from the Slave Point and Swan Hills carbonates of the Devonian Beaverhill Lake Group. Oil is trapped at the depositional up-dip edge of a complex carbonate platform. This reservoir has been produced under enhanced recovery, in the form of waterfloods, which have been active since 1965. The current watercut from the pool is approximately 79%. This low watercut suggests significant remaining recoverable oil. Numerous optimization and field operating cost reduction opportunities are available on these assets. We have identified further drilling exploitation opportunities consisting of horizontal wells in the platform and vertical wells in the fringing reef.

The wells are pipeline-connected to the main oil battery. The oil is sales line connected, NGLs are trucked and the gas is conserved on site for power generation. The gas is contracted to a joint venture power station and is not sold in the market. Produced water is separated and re-injected to support the existing waterfloods.

The House Mountain assets averaged 1,945 Boe/d (91% light and medium crude oil and 9% NGLs) during 2024.

Northern Alberta, Grande Prairie, Area

The Grande Prairie assets are located to the west and to the north of the City of Grande Prairie, including the Wapiti and Knopcik areas and also include our Worsley and Mica, British Columbia areas. In aggregate, during 2024, this property produced 1,373 Boe/d (28% light and medium crude oil, 26% NGLs and 46% conventional natural gas). The main producing horizons include Cretaceous Dunvegan sandstones and Triassic aged carbonates and sandstones. Multiple infill drilling and extension opportunities are planned over the next several years at our Knopcik Dunvegan oil development along with further select oil development potential in the Triassic at Mica. The majority of our production here is pipeline-connected and operated, however natural gas is generally processed through third party facilities.

During 2024 we drilled 2 (2.0 net) wells in this area.

Central Alberta, Wainwright Area

The Wainwright assets are located 195 kilometers southeast of Edmonton. The Wainwright properties include the Chauvin, Forestburg and Hayter areas, as well as our Killam and Viking-Kinsella areas which were acquired during 2021. Also included amongst our Central Alberta group of assets is our Buffalo field, which is located approximately 150 kilometers northeast of Edmonton, and produces oil from the lower Mannville. Combined, in 2024, this property produced approximately 5,836 Boe/d (20% light and medium crude oil, 77% heavy oil and 3% conventional natural gas). The base production in Wainwright has a low production decline of approximately 6% per year. The majority of production is pipeline-connected.

The Wainwright properties primarily produce from the Middle Mannville Sparky formation which is a sandstone shale sequence deposited in a shallow-water progradational delta environment. The productive interval of the Sparky formation consists of coarsening-upward sequences with sandstones that are both fine and coarse grained. The Sparky sandstone responds favorably to enhanced recovery. Our producing reservoirs are under enhanced recovery, in the form of waterflood.

Further opportunity in this area exists in the exploitation of the Rex, Sparky, GP and Waseca sandstones by drilling horizontally into this channel facies at the base of the Upper Mannville. There are also infill horizontal drilling prospects in the Cummings formation in the Hayter area.

During 2024, we successfully drilled 6 (6.0 net) new multi-leg horizontal wells in the Wainwright area. Our 2025 budget includes the drilling of another 2 (2.0 net) wells in this area.

Midale, Saskatchewan

The Midale property is located in southeast Saskatchewan approximately 150 kilometers south and east of Regina. The Midale assets consist of operated production from the Midale Unit where we hold a 77% working interest. We also hold interests in a small amount of non-unit land in the Midale area, as well as a minor interest in the Weyburn Unit. The Midale and Weyburn Units are two of the lowest decline oil units in Western Canada at less than 5% and both units have significant development drilling upside. Our average 2024 production from these properties was 3,199 bbl/d of 29° API light/medium oil.

The Midale Unit was discovered in 1953 and is part of a large Mississippian oil trend in the Williston Basin. The production interval is from the Midale Carbonate overlain and underlain from impervious anhydrite beds. The gross interval is subdivided into the Marly and the Vuggy intervals. Vertical and horizontal well development currently exploits both intervals. The Midale Unit waterflood was implemented in 1963. In 2005, the first of three stages of the current CO_2 EOR scheme was implemented. Currently the unit is operating with approximately 70% of the production supported by waterflood, while nearly half of this waterflood area is also supported by CO_2 injection. The CO_2 EOR scheme provides incremental oil recovery beyond that of the waterflood alone. The wells are pipeline-connected to a main oil battery supporting the water, gas and CO_2 injection. The oil is pipeline-connected to sales and the produced gas is combined with CO_2 for reinjection into the reservoir.

During 2024, we drilled 2 (1.5 net) horizontal production wells at Midale, along with 2 (1.5 net) horizontal injection wells to enhance and expand our EOR scheme.

Reford, Saskatchewan

Our Reford Project is our first SAGD project for development. At Reford, a thick Waseca channel defined by existing and recently drilled assessment wells and 3D seismic, with porosities over 30% and gross pay up to 20 metres, has established a significant heavy oil resource.

We have decided to focus our development on building a 6,000 bopd SAGD facility. Our decision to start with this size of project was based on the capital cost and at 6,000 bopd the Reford Project's potential to produce at a flat production profile for approximately 15 to 20 years. By taking a conservative first step into SAGD, we expect to be able to increase our sustainability in a controlled growth environment while developing a project that will further our low decline production model. We currently anticipate the Reford Project will be on production in the third quarter of 2025.

Additional SAGD Projects

Two additional stand-alone projects both with up to 10,000 bopd of heavy oil potential have been identified by us. We plan over the next two years to complete assessment drilling to assist in finalizing development plans for these assets.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2024.

	OIL WELLS(1)				NATURAL GAS WELLS(1)			
	PRODUCING		NON-PRODUCING		PRODUCING		NON-PRODUCING	
	Gross	NET	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	1,572	1,394	757	586	132	78	108	62
British Columbia	13	12	1	1	1	1	4	4
Saskatchewan(2)	685	186	351	39	-	-	-	-
Total	2,270	1,592	1,109	626	133	79	112	66

Notes:

(1) This table excludes abandoned and service wells such as: water source, water injection and disposal wells.
(2) Includes 749 gross wells in the Weyburn Unit where Cardinal has a 0.01244% working interest.

Of the non-producing wells, 50 gross (40 net) were capable of production and had reserves assigned to them. As of the date of this Annual Information Form, 28 gross (22 net) of these wells had been on production within the last 24 months.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2024.

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES	
	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	162,725	116,080	421,391	340,777	584,116	456,857
British Columbia	5,715	5,208	11,218	9,664	16,933	14,872
Saskatchewan	70,836	65,568	33,338	28,005	104,174	93,573
Total	239,276	186,856	465,947	378,446	705,223	565,302

Notes:

(1) Rights to explore, develop and exploit 18,710 net acres of our land holdings could expire by December 31, 2025 if not continued.

(2) When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported only once. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

(3) Total values may not add due to rounding.

Properties with no Attributed Reserves

As at December 31, 2024 we held 332,780 gross acres (250,767 net acres) to which no reserves are currently attributed, all of which are located in Canada. Rights to explore, develop and exploit 8,781 net acres of these land holdings could expire by December 31, 2025 if not continued. We have no material work commitments other than abandonment obligations on these properties and the majority of this acreage is located in our non-core operating areas. When determining gross and net acreage, where we hold two or more leases granting stratigraphic interests which overlap geographically, the acreage is reported for each lease; where we hold two or more stratigraphic interests in a single lease that overlap geographically, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties With no Attributed Reserves

Our asset base focuses on sustainable low decline production with little capital allocated to the exploration or development of properties with no attributed reserves. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. In addition, there are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. All abandonment and reclamation costs have been included in the Consolidated Reserve Report, including costs for properties with no attributed reserves. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*" and "*Risk Factors*".

Forward Contracts

Our operational results and financial condition are dependent upon the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic and political factors, supply and demand factors, as well as weather and conditions in other oil and natural gas regions of the world. Any upward or downward movement in oil and natural gas prices could have an effect on our financial condition.

We have a hedging policy using, amongst others, collars, puts and fixed price swaps which allows us to hedge our gross oil, NGLs and natural gas forward production profile of three years, of up to 75% of average forward 12 months production and up to 50% and 30% of the following 12 and 24 months, respectively. These hedging activities could expose us to losses or gains. See "*Risk Factors – Hedging*".

Cardinal has fixed the WCS differential and WTI oil price for certain months in 2025 and has hedged AECO gas prices throughout 2025 all at varying volumes outlined below. We will continue to monitor the spot and forward prices as well as expected expenditure levels in 2025.

As of the date of this Annual Information Form, Cardinal had the following commodity derivative contracts outstanding:

TYPE OF INSTRUMENT	TERM	QUANTITY	STRIKE PRICE ($US)
USD WCS Differential Swap	January 2025 – March 2025	1,000 bbl/d	$ (14.00)
USD WCS Differential Swap	April 2025 – September 2025	5,000 bbl/d	$ (12.75)
USD WTI Swap	January 2025 – March 2025	2,000 bbl/d	$ 75.50
AECO Collar	January 2025 – December 2025	2,500 GJ/d	$1.75 – $2.70
AECO Collar	April 2025 – March 2026	2,500 GJ/d	$2.00 – $3.31

For 2025, Cardinal has fixed electricity contracts in place that cover approximately 60% of our Alberta power requirements at $84.75/MWh.

Tax Horizon

Based on available tax pools, forecasted capital expenditures and forecasted commodity prices at December 31, 2024, we do not expect to pay current income taxes until 2027 or beyond. Any potential taxes payable beyond 2027 would be affected by commodity prices, capital expenditures and production volumes.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2024.

EXPENDITURE[1]	YEAR ENDED DECEMBER 31, 2024 ($000s)
Property acquisition costs – Unproved properties [2]	5,397
Property acquisition costs – Proved properties	360
Property dispositions – Proved properties	-
Exploration costs [3]	4,073
Development costs [4]	173,265
Total	183,095

Notes:

(1) Expenditures do not include office equipment, capitalized general and administrative costs and related share-based compensation or non-cash expenditures for the abandonment and decommissioning obligation. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data – Significant Factors or Uncertainties Affecting Reserves Data – Additional Information concerning Abandonment and Reclamation Costs*".

(2) Cost of land acquired and non-producing lease rentals on those lands.

(3) Geological and geophysical capital expenditures and drilling costs for exploration wells and stratigraphic test wells.

(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The following table sets forth the gross and net development wells in which we participated during the year ended December 31, 2024.

	DEVELOPMENT		EXPLORATORY	
	GROSS	NET	GROSS	NET
Conventional Natural Gas	-	-	-	-
Light and Medium Crude Oil	10	9.5	-	-
Heavy Crude Oil	9	9.0	4	4.0
Dry	-	-	-	-
Service	4	3.5	-	-
Total	23	22.0	4	4.0

Cardinal expects to maintain activities in and around its principal properties and concentrated on oil development. Cardinal will also be focusing on development of its Reford Project in 2025.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2025, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the heading "*Disclosure of Reserves Data*".

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	HEAVY CRUDE OIL (Bbls/d)	CONVENTIONAL NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	BOE[(1)] (Boe/d)
Proved	10,209	8,010	13,515	767	21,239
Probable	380	990	474	28	1,477
Proved plus Probable	10,590	9,000	13,989	795	22,716

Note:

(1) No one field represents more than 20% of our forecast production.

Production History

The following table indicates our average daily production for the year ended December 31, 2024.

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	HEAVY CRUDE OIL (Bbls/d)	NATURAL GAS LIQUIDS (Bbls/d)	CONVENTIONAL NATURAL GAS (Mcf/d)	BOE (Boe/d)
Bantry [(1)]	2,203	2,177	97	5,855	5,453
Grande Prairie	380	-	362	3,786	1,373
House Mountain	1,764	-	181	-	1,945
Mitsue [(2)]	1,826	1,444	173	3,163	3,970
Wainwright [(3)]	1,144	4,523	4	990	5,836
Midale, SK	3,199	-	-	1	3,199
Total	10,516	8,144	817	13,795	21,776

Notes:

(1) Includes the Alderson, Duchess, Rosemary, Kininvie and Tide Lake areas.
(2) Includes the Nipisi, Worsley and Mica areas.
(3) Includes the Chauvin, Forestburg, Hayter, Killam North and Kinsella areas.

The following table summarizes certain information in respect of our production, product prices received, royalties, operating costs and resulting netback for the periods indicated below:

	QUARTER ENDED 2024				YEAR ENDED
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31	DEC. 31, 2024
Average Daily Production (1)					
Light and Medium Crude Oil (Bbls/d)	10,873	10,816	9,775	10,605	10,516
Heavy Crude Oil (Bbls/d)	7,439	8,457	8,455	8,222	8,144
Natural Gas Liquids (Bbls/d)	854	811	778	827	817
Conventional Natural Gas (Mcf/d)	15,155	13,752	12,719	13,569	13,795
Combined (Boe/d)	21,692	22,376	21,128	21,916	21,776
Average Prices Received					
Light and Medium Crude Oil ($/Bbl)	88.47	100.31	86.22	87.79	90.80
Heavy Crude Oil ($/Bbl)	67.92	85.85	86.13	76.15	79.39
Natural Gas Liquids ($/Bbl)	39.72	39.49	35.61	34.01	37.23
Conventional Natural Gas ($/Mcf)	2.63	1.31	0.78	1.55	1.61
Combined ($/Boe)	71.04	83.17	76.14	73.29	75.95
Royalties					
Light and Medium Crude Oil ($/Bbl)	17.47	17.36	18.60	18.75	18.03
Heavy Crude Oil ($/Bbl)	11.64	17.19	14.80	12.88	14.22
Natural Gas Liquids ($/Bbl)	5.41	9.76	1.60	3.86	5.29
Conventional Natural Gas ($/Mcf)	0.14	0.14	0.01	0.03	0.08
Combined ($/Boe)	13.06	15.33	14.60	14.07	14.27
Operating Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	28.91	25.29	27.05	24.04	26.16
Heavy Crude Oil ($/Bbl)	28.28	24.91	24.88	24.69	25.82
Natural Gas Liquids ($/Bbl)	11.42	11.76	13.88	10.35	11.82
Conventional Natural Gas ($/Mcf)	0.62	0.70	0.82	0.42	0.64
Combined ($/Boe)	26.17	23.65	24.40	22.76	24.23
Transportation Costs					
Light and Medium Crude Oil ($/Bbl)	0.67	0.79	0.30	1.20	0.75
Heavy Crude Oil ($/Bbl)	1.43	1.57	1.45	1.20	1.41
Natural Gas Liquids ($/Bbl)	2.76	2.16	2.59	2.06	2.39
Conventional Natural Gas ($/Mcf)	0.24	0.16	0.18	0.17	0.19
Combined ($/Boe)	1.10	1.15	0.92	1.21	1.10
Resulting Netback (4)					
Light and Medium Crude Oil ($/Bbl)	41.42	56.87	40.27	43.80	45.86
Heavy Crude Oil ($/Bbl)	26.57	42.18	45.00	37.38	37.94
Natural Gas Liquids ($/Bbl)	20.13	15.81	17.54	17.74	17.73
Conventional Natural Gas ($/Mcf)	1.63	0.31	0.23	0.93	0.70
Combined ($/Boe)	30.71	43.04	36.22	35.25	36.35

Notes:

(1) Before the deduction of royalties.

(2) These are composed of direct costs incurred to operate both oil and natural gas wells. A number of assumptions are required to allocate these costs between product types.

(3) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.

(4) Netback is a non-GAAP measure. Refer to the section entitled "*Non-IFRS and Other Financial Measures*" contained within our MD&A for the year ended December 31, 2024, available on SEDAR+ at *www.sedarplus.ca*, for certain additional disclosures relating to this non-GAAP measure, which information is incorporated in this Annual Information Form by reference.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Share Capital

We are authorized to issue an unlimited number of Common Shares without nominal or par value and an unlimited number of first preferred shares. A description of our share capital is set forth below. For a complete description of our share capital, reference should be made to our Articles, a copy of which has been filed on SEDAR+ at *www.sedarplus.ca*.

Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

Voting Rights: Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of shares other than our Common Shares).

Dividends: Holders of Common Shares are entitled to receive dividends as and when declared by our Board of Directors on the Common Shares as a class, subject to the prior satisfaction of all preferential rights to dividends attached to other classes of shares ranking in priority to the Common Shares in respect of dividends.

Ranking: In the event of any liquidation, dissolution or winding up of us, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all other classes of shares ranking in priority to the Common Shares in respect of return of capital on dissolution, holders of Common Shares are entitled to share rateably, together with the holders of shares of any other class of shares ranking equally with the Common Shares, in respect of a return of capital on dissolution, in such of our assets as are available for distribution.

If our Board of Directors declare a dividend on the Common Shares payable in whole or in part in fully paid and non-assessable Common Shares (the portion of the dividend payable in Common Shares referred to as a "stock dividend"), the following provisions shall apply:

(a) unless otherwise determined by the Board of Directors in respect of a particular stock dividend: (i) the number of Common Shares (which shall include any fractional Common Shares) to be issued in satisfaction of the stock dividend shall be determined by dividing (A) the dollar amount of the particular stock dividend, by (B) the "Average Market Price" of a Common Share on the Toronto Stock Exchange, with the "Average Market Price" calculated by dividing the total value of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) by the total volume of Common Shares traded on the Toronto Stock Exchange (or if the Common Shares are not traded on the Toronto Stock Exchange, on any other recognized exchange or market on which the Common Shares are traded) over the five trading day period immediately prior to the payment date of the applicable stock dividend on the Common Shares; and (ii) the value of a Common Share to be issued for the purposes of each stock dividend declared by the Board of Directors shall be deemed to be the Average Market Price of a Common Share;

(b) to the extent that any stock dividend paid on the Common Shares represents one or more whole Common Share payable to a registered holder of Common Shares, such whole Common Shares shall be registered in the name of such holder. Common Shares representing in the aggregate all of the fractions amounting to less than one whole Common Share which might otherwise have been payable to registered holders of Common Shares by reason of such stock dividend shall be issued to our transfer agent as the agent of such registered holders of Common Shares. Our transfer agent shall credit to an account for each such registered holder all fractions of a Common Share amounting to less than one whole share issued by us by way of stock dividends in respect of the Common Shares registered in the name of such holder. From time to time, when the fractional interests in a Common Share held by our transfer agent for the account of any registered holder of Common Shares are equal to or exceed in the aggregate one additional whole Common Share, the transfer agent shall cause such additional whole Common Share to be registered in the name of such registered holder and thereupon only the excess fractional interest, if any, will continue to be held by the transfer agent for the account of such registered holder. Common Shares held by the transfer agent representing fractional interests shall not be voted;

(c) if at any time we have reason to believe that tax should be withheld and remitted to a taxation authority in respect of any stock dividend paid or payable to a Shareholder in Common Shares, we have the right to sell, or to require our transfer agent in each case as agent of such Shareholder, to sell all or any part of the Common Shares or any fraction thereof so issued to such holder in payment of that stock dividend or one or more subsequent stock dividends through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, and to cause our transfer agent to remit the cash proceeds from such sale to such taxation authority (rather than such holder) in payment of such tax to be withheld. This right of sale may be exercised by notice given by us to such holder and to us or our transfer agent stating the name of the holder, the number of Common Shares to be sold and the amount of the tax which we have reason to believe should be withheld. Upon receipt of such notice the transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and Cardinal or our transfer agent, as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and deliver the proceeds therefrom to the applicable taxation authority on behalf of us. Any balance of the cash sale proceeds not remitted by us in payment of the tax to be withheld shall be payable to the holder whose Common Shares were so sold by the transfer agent;

(d) if at any time we shall have reason to believe that the payment of a stock dividend to any holder who is resident in or otherwise subject to the laws of a jurisdiction outside Canada might contravene the laws or regulations of such jurisdiction, or could subject us to any penalty thereunder or any legal or regulatory requirements not otherwise applicable to us, we shall have the right to sell, or to require our transfer agent in each case, as agent of such Shareholder, to sell through the facilities of the Toronto Stock Exchange or other stock exchange on which the Common Shares are listed for trading, the Common Shares or any fraction thereof so issued and to cause our transfer agent to pay the cash proceeds from such sale to such holder. The right of sale shall be exercised in the manner provided in subparagraph (c) above except that in the notice there shall be stated, instead of the amount of the tax to be withheld, the nature of the law or regulation which might be contravened or which might subject us to any penalty or legal or regulatory requirement. Upon receipt of the notice, we or our transfer agent shall, unless a certificate or other evidence of registered ownership for the Common Shares has at the relevant time been issued in the name of the holder, sell the Common Shares as aforementioned and we or our transfer agent, as applicable, shall be deemed for all purposes to be the duly authorized agent of the holder with full authority on behalf of such holder to effect the sale of such Common Shares and to deliver the proceeds therefrom to such holder;

(e) upon any registered holder of Common Shares ceasing to be a registered holder of one or more Common Shares, such holder shall be entitled to receive from our transfer agent, and the transfer agent shall pay as soon as practicable to such holder, an amount in cash equal to the proportion of the value of one Common Share that is represented by the fraction less than one whole Common Share at that time held by our transfer agent for the account of such holder and, for the purpose of determining such value, each Common Share shall be deemed to have the value equal to the Average Market Price in respect of the last stock dividend paid by us prior to the date of such payment; and

(f) for the purposes of the foregoing: (i) the calculation of a fraction of a Common Share payable to a Shareholder by way of a stock dividend and the calculation of the Average Market Price shall be computed to six decimal places, and shall be rounded to the nearest sixth decimal place; and (ii) neither us nor our transfer agent shall have any obligation to register any Common Share in the name of a person, to deliver a certificate or other document representing Common Shares registered in the name of a Shareholder or to make a cash payment for fractions of a Common Share, unless all applicable laws and regulations to which we and/or our transfer agent are, or as a result of such action may become, subject, shall have been complied with to their reasonable satisfaction.

First Preferred Shares

Voting Rights: Holders of first preferred shares shall be entitled to receive notice of, to attend and to one vote per first preferred share held at any meeting of the Shareholders (other than meetings of a class or series of shares of Cardinal other than the first preferred shares as such).

Dividends: Holders of first preferred shares shall be entitled to receive if, as and when declared by our Board of Directors out of the monies of our applicable to the payment of dividends, such dividends in any financial year as the Board of Directors in its absolute discretion may by resolution determine, and the directors may, subject to certain restrictions on dividends, declare dividends on any other class of share at different times or at the same time in different amounts than dividends declared on the first preferred shares.

Ranking: In the event of the liquidation, dissolution or winding up of us or other distribution of our assets among Shareholders for the purpose of winding up our affairs, the holders of first preferred shares shall be entitled to receive the redemption value of the first preferred shares per share, together with any accrued and unpaid dividends thereon up to the date of commencement of any such liquidation, dissolution, winding up or other distribution of our assets and to be paid all such money before any money shall be paid or property or assets distributed to the holders of any Common Shares or other shares in our capital ranking junior to the first preferred shares with respect to return of capital. After payment to the holders of the first preferred shares of the amounts so payable to them in accordance, the holders of first preferred shares shall not be entitled to share in any further distribution of our property or assets.

Warrants

The Warrants were issued under and are governed by the Warrant Indenture. The following is a summary of the material attributes and characteristics of the Warrants. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the Warrant Indenture, a copy of which has been filed on SEDAR+ at *www.sedarplus.ca*. See "*Risk Factors – Specific Risks Related to the Debentures and the Warrants*".

Each Warrant is transferable and entitles the holder thereof to acquire one Common Share at an exercise price of $7.00 per Common Share at any time prior to 5:00 p.m. (Calgary time) on January 3, 2028, subject to adjustment in certain customary events, after which time the Warrants will expire. We have appointed the principal transfer office of the Warrant Agent in Calgary, Alberta as the location at which the Warrants may be surrendered for exercise, transfer or exchange. Under the Warrant Indenture, we may, subject to applicable law, purchase by private contract or otherwise, any of the Warrants then outstanding, and any Warrants so purchased will be cancelled.

The Warrant Indenture provides for adjustment in the number of Common Shares issuable upon the exercise of the Warrants and/or the exercise price per Common Share upon the occurrence of certain events, including:

(a) the issuance of Common Shares or securities exchangeable for or convertible into Common Shares to all or substantially all of the holders of our Common Shares by way of a stock dividend or other distribution (other than a dividend in the ordinary course or a distribution of Common Shares upon the exercise of any Warrants, options or similar convertible securities outstanding as of the date of the Warrant Indenture);

(b) the subdivision, redivision or change of our Common Shares into a greater number of Common Shares;

(c) the consolidation, reduction or combination of our Common Shares into a lesser number of Common Shares;

(d) the issuance to all or substantially all of the holders of our Common Shares of rights, options or warrants under which such holders are entitled, during a period expiring not more than 45 days after the record date for such issuance, to subscribe for or purchase Common Shares, or securities exchangeable for or convertible into Common Shares, at a price per share to the holder (or at an exchange or conversion price per share) of less than 95% of the "Current Market Price" ("**Current Market Price**" is defined in the Warrant Indenture as the weighted average of the trading price per Common Share for each day there was a closing price for the twenty consecutive “Trading Days”, as defined in the Warrant Indenture, ending immediately prior to such date on the Toronto Stock Exchange) for the Common Shares on such record date; and

(e) the distribution to all or substantially all of the holders of our Common Shares of securities of any class, whether of us or any other entity, of shares (other than Common Shares), rights, options or warrants to subscribe for or purchase Common Shares or securities exchangeable or convertible into any Common Shares (other than pursuant to a "Rights Offering", as defined in the Warrant Indenture), evidences of indebtedness or any property or other assets.

The Warrant Indenture also provides for adjustment in the class and/or number of securities issuable upon the exercise of the Warrants and/or exercise price per security in the event of the following additional events:

(a) reclassifications of our Common Shares;

(b) consolidations, amalgamations, arrangements or mergers of us with or into any other corporation or other entity (other than consolidations, amalgamations, arrangements or mergers which do not result in any reclassification of the outstanding Common Shares or a change of our Common Shares into other shares); or

(c) the transfer of our undertaking or assets as an entirety or substantially as an entirety to another corporation or other entity.

No adjustment in the exercise price or the number of Common Shares issuable upon the exercise of the Warrants will be required to be made unless the cumulative effect of such adjustment or adjustments would result in a change of at least 1% in the exercise price.

We have agreed in the Warrant Indenture that, during the period in which the Warrants are exercisable, we will give notice to the Warrant Agent and to the holders of the Warrants of certain stated events, including events that would result in an adjustment to the exercise price for the Warrants or the number of Common Shares issuable upon exercise of the Warrants, at least 14 days prior to the record date of such event, if any.

No fractional Common Shares will be issuable upon the exercise of any Warrants, and no cash or other consideration will be paid in lieu of fractional Common Shares. Holders of Warrants will not have any voting or pre-emptive rights or any other rights which a holder of our Common Shares would have in respect of such Warrants.

The Warrant Indenture provides that, from time to time, we may amend or supplement the Warrant Indenture for certain purposes, without the consent of the holders of the Warrants, including curing defects or inconsistencies or making any change that does not prejudice the rights of any holder. Any amendment or supplement to the Warrant Indenture that would prejudice the interests of the holders of Warrants may only be made by "extraordinary resolution", which is defined in the Warrant Indenture as a resolution either: (i) passed at a meeting of the holders of Warrants at which there are holders of Warrants present in person or represented by proxy representing at least 10% of the aggregate number of the then outstanding Warrants (unless such meeting is adjourned to a prescribed later date due to the lack of quorum) and passed by the affirmative vote of the holders of Warrants present in person or by proxy representing not less than 66⅔% of the aggregate number of all the then outstanding Warrants represented at the meeting and voted on the poll upon such resolution; or (ii) adopted by an instrument in writing signed by the holders of Warrants representing not less than 66⅔% of the aggregate number of all the then outstanding Warrants.

Under the Warrant Indenture, original purchasers of Warrants have certain contractual rights of rescission pursuant to the terms of the Warrants to receive the amount paid for the Warrants, provided such remedy for rescission is exercised within the timeframe set forth in the Warrant Indenture.

Credit Facility

The $275 million Credit Facility is currently comprised of a $250 million syndicated term credit facility and a $25 million non-syndicated operating line credit facility. The Credit Facility is available on a revolving basis until May 31, 2025 and may be extended for a further 364 day period, subject to approval by the syndicate. If not extended, the Credit Facility will cease to revolve, the applicable margins will increase by 0.5% and all outstanding advances will be repayable on May 31, 2026. On the redetermination date, the lenders could reduce the borrowing base to below the current drawn amount, in this case, the short fall would have to be repaid within 60 days.

The available lending limits of the Credit Facility are reviewed semi-annually based on the syndicate's interpretation of our reserves, future commodity prices and costs. As the available lending limit of the Credit Facility is based on the syndicate's interpretation of our reserves and future commodity prices and costs, there can be no assurance that the amount of the Credit Facility will not decrease at the next scheduled review. The next scheduled review date is on or before May 31, 2025.

Advances under the Credit Facility are available by way of prime rate loans, which bear interest at the banks' prime lending rate plus 2.00% to 6.75%, and CORRA and/or SOFR loans, which are subject to fees and margins ranging from 3.00% to 7.75%. Interest and standby fees on the undrawn amounts of the Credit Facility depend upon certain ratios.

The Credit Facility is secured by a demand debenture pursuant to which a security interest is granted over all of our assets. There are no financial covenants related to the Credit Facility, provided that we are not in default of the terms of the Credit Facility. See "*Risk Factors – Credit Facility Arrangements*".

Debentures

The Debentures were issued under and are governed by the Debenture Indenture. The following is a summary of the material attributes and characteristics of the Debentures. This summary does not purport to be complete and is subject to and qualified in its entirety by reference to the terms of the Debenture Indenture, a copy of which has been filed on SEDAR+ at *www.sedarplus.ca*. See "*Risk Factors – Specific Risks Related to the Debentures and the Warrants*".

General

The Initial Debentures were issued on January 3, 2025 in the aggregate principal amount of $60,000,000 and the Second Series Debentures were issued on March 4, 2025 in the aggregate principal amount of $45,000,000. The aggregate principal amount of Initial Debentures that can be issued under the Debenture Indenture is limited to $60,000,000. The aggregate principal amount of Second Series Debentures that can be issued under the Debenture Indenture is unlimited and we may, from time to time, without the consent of the Debentureholders, and subject to the prior written approval of the Toronto Stock Exchange, issue additional Second Series Debentures. In addition, we may, from time to time, without the consent of the Debentureholders, issue additional debentures of a different series under the Debenture Indenture.

The Initial Debentures have a maturity date of March 31, 2030 and were issued in denominations of $1,000 and integral multiples thereof. The Initial Debentures bear interest from and including the date of issue at the rate of 7.75% per annum, payable semi-annually in arrears on the last business day in March and September of each year, commencing on March 31, 2025. The first interest payment on the Initial Debentures will include accrued and unpaid interest from the issue date to, but excluding, March 31, 2025.

The Second Series Debentures bear interest from and including the date of issue (with the exception of any Second Series Debentures issued after March 4, 2025 and prior to September 30, 2025 which shall bear interest from and including March 4, 2025) at the rate of 8.25% per annum, payable semi-annually in arrears on the last business day in March (with the exception of the first interest payment for Second Series Debentures issued prior to September 30, 2025) and September of each year, commencing on September 30, 2025. The first interest payment for Second Series Debentures issued prior to September 30, 2025 will include accrued and unpaid interest from March 4, 2025 to, but excluding, September 30, 2025.

The principal amount of the Debentures is payable in lawful money of Canada or, at our option, subject to the receipt of applicable regulatory approvals ((including the approval of the Toronto Stock Exchange) and provided that no Event of Default (as defined in the Debenture Indenture and as described below) has occurred and is continuing, by delivery of fully paid, non-assessable and freely tradeable Common Shares as further described below under the heading "*Method of Payment — Payment of Principal on Redemption or at Maturity*". The interest on the Debentures is payable in lawful money of Canada, including, at our option, in accordance with the Common Share Interest Payment Election as defined and described below under the heading "*Method of Payment — Interest Payment Election*". The Credit Facility may restrict payment or repayment, as applicable, under, pursuant to or relating to the Debentures, including without limitation, any interest payments thereon. See "*Risk Factors – Specific Risks Related to the Debentures and the Warrants – Credit Risk and Earnings Coverage Ratios*".

The Debentures are our direct senior unsecured obligations and are not secured by any mortgage, pledge, hypothec or other charge and will be subordinated to certain of our other liabilities as described below under the heading "*Subordination and Ranking".* The Debenture Indenture does not restrict us from incurring additional indebtedness for borrowed money, including indebtedness that ranks senior to the Debentures, or otherwise or from mortgaging, pledging or charging our properties to secure any indebtedness.

The Debenture Trustee is the trustee under the Debenture Indenture and is also our transfer agent.

Subordination and Ranking

The Debentures are our direct senior unsecured obligations and rank (i) subordinate to all of our existing and future Senior Secured Indebtedness (as defined below) (including the Credit Facility); (ii) subordinate to all of our existing and future secured indebtedness that is not Senior Secured Indebtedness, but only to the extent of the value of the assets securing such other secured indebtedness, or our other indebtedness that ranks senior to the Debentures by operation of law; (iii) *pari passu* with each debenture issued under the Debenture Indenture (including the Initial Debentures and the Second Series Debentures) and with all of our other present and future unsecured unsubordinated indebtedness that is not Senior Secured Indebtedness or indebtedness that is described in (ii) above, including trade creditors; (iv) senior in right of payment to our indebtedness that by its terms is subordinated in right of payment to the Debentures, and (v) structurally subordinated to all existing and future obligations, including indebtedness (including indebtedness under or in relation to Senior Secured Indebtedness) and trade payables, of our subsidiaries (if any). The payment of principal and premium, if any, of, and interest on, the Debentures will be subordinated in right of payment to all of our Senior Secured Indebtedness and the indebtedness contemplated in (ii) above, as set forth in the Debenture Indenture. The Debenture Indenture does not restrict us or our subsidiaries from incurring additional indebtedness (senior, unsubordinated or otherwise) or from mortgaging, pledging or charging our properties to secure any indebtedness or liabilities. None of our subsidiaries (if any) will guarantee the Debentures.

"**Senior Secured Indebtedness**" is defined in the Debenture Indenture to mean any indebtedness (including without limitation, under guarantees, indemnities and similar instruments) of us and our subsidiaries (including, without limitation, principal, interest, fees, premiums, make whole amounts and any other amounts owing in respect of such indebtedness) that is secured by a first priority lien on a material portion of our assets or of our subsidiaries, which for certainty shall include all indebtedness under the agreement in respect of the Credit Facility and derivative, swap, hedging or cash management arrangements with any lender or affiliate of any lender under the Credit Facility, and any replacement, amendment or restatement of the Credit Facility.

The Debenture Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to us, or to our property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or voluntary winding-up of us, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of us, then holders of Senior Secured Indebtedness will receive payment in full before the holders of Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon.

The Debenture Indenture also provides that no payment on account of our indebtedness, liabilities and obligations under the Debenture Indenture or the Debentures, whether on account of principal, premium, interest or otherwise, shall be made by us: (i) during any default with respect to any Senior Secured Indebtedness permitting the holders thereof to accelerate the maturity thereof or any borrowing base shortfall; or (ii) if such payment would result in a default with respect to any Senior Secured Indebtedness permitting the holders thereof to accelerate the maturity thereof or a borrowing base shortfall; unless and until such default or borrowing base shortfall shall have been cured or waived or shall have ceased to exist, and neither the Debenture Trustee nor the holders of Debentures shall be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit on account of the Debentures after the happening of such a default or borrowing base shortfall, and unless and until such default or borrowing base shortfall shall have been cured or waived or shall have ceased to exist, such payments shall be held in trust for the benefit of, and, if and when such Senior Secured Indebtedness shall have become due and payable, shall be paid over to, the Senior Creditors (as defined in the Debenture Indenture) until all such Senior Secured Indebtedness shall have been paid in full, after giving effect to any concurrent payment or distribution to the Senior Creditors. Furthermore, upon the maturity of any Senior Secured Indebtedness by lapse of time, acceleration (unless acceleration is rescinded) or otherwise, then all such matured Senior Secured Indebtedness shall first be paid in full, or shall first have been duly provided for, before any payment is made on account of the Debentures. In addition to the foregoing, our ability to make payments on the Debentures may be limited by the terms of any Senior Secured Indebtedness, including the Credit Facility, including if it would or would reasonably be expected to result in a default thereunder or during the continuance of a default, or borrowing base shortfall or event of default thereunder.

The Debenture Trustee is authorized to take such action as necessary or appropriate to effect the subordination of the Debentures to Senior Secured Indebtedness. Upon our request, the Debenture Trustee will enter into a subordination agreement with us and the holder of the Senior Secured Indebtedness.

Redemption

The Initial Debentures are not redeemable prior to March 31, 2028 and the Second Series Debentures are not redeemable prior to September 30, 2028, except upon the satisfaction of certain conditions after a Change of Control (as defined and described below) has occurred.

On and after March 31, 2028 and prior to March 31, 2029, the Initial Debentures may be redeemed by us, in whole or in part, at a redemption price equal to 103.875% of the principal amount thereof plus accrued and unpaid interest, if any, up to but excluding the date of redemption. On and after March 31, 2029 and prior to maturity, the Initial Debentures may be redeemed by us, in whole or in part, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, if any, up to but excluding the date of redemption. We shall provide not more than 60 days' nor less than 30 days' prior notice of redemption.

On and after September 30, 2028 and prior to September 30, 2029, the Second Series Debentures may be redeemed by us, in whole or in part, at a redemption price equal to 104.125% of the principal amount thereof plus accrued and unpaid interest, if any, up to but excluding the date of redemption. On and after September 30, 2029 and prior to maturity, the Second Series Debentures may be redeemed by us, in whole or in part, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, if any, up to but excluding the date of redemption. We shall provide not more than 60 days' nor less than 30 days' prior notice of redemption.

In the case of redemption of less than all of the Initial Debentures or the Second Series Debentures, as the case may be, the Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the Toronto Stock Exchange, if applicable. We also have the right to purchase Debentures in the market, by tender or by private contract at any time subject to regulatory requirements.

Any redemption of Debentures will be subject to compliance with the Credit Facility and the terms of any other future Senior Secured Indebtedness.

Change of Control

Within 30 days following the occurrence of a Change of Control, we are required to make an offer in writing to purchase within the time period more specifically set out in the Debenture Indenture, all the Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 100% of the principal amount thereof plus accrued and unpaid interest earned thereon up to, but excluding, the date of acquisition (the "**Debenture Offer Price**").

Under the Debenture Indenture, a "**Change of Control**" will be deemed to have occurred at such time after the original issuance of the Debentures upon: (a) the acquisition by any person, or group of persons acting jointly or in concert (within the meaning of National Instrument 62-104 — *Take-Over Bids and Issuer Bids*), of voting control or direction over more than 50% of the voting rights attached to the outstanding Common Shares; or (b) the sale, transfer or other disposition, directly or indirectly, of all or substantially all of the assets and property of us and our subsidiaries, taken as a whole, but shall not include a sale, merger, reorganization, arrangement, combination or other similar transaction if the previous holders of Common Shares hold more than 50% of the voting control or direction in such merged, reorganized, arranged, combined or other continuing entity (and in the case of a sale of all or substantially all of the assets, in the entity which has acquired such assets) immediately following the completion of such transaction.

The Debenture Indenture contains notification and repurchase provisions requiring us to give written notice to the Debenture Trustee of the occurrence of a Change of Control within 30 days of such event together with the Debenture Offer. The Debenture Trustee will thereafter promptly deliver to each holder of Debentures a notice of the Change of Control together with a copy of the Debenture Offer to repurchase all the outstanding Debentures.

If 90% or more of the aggregate principal amount of the applicable series of Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to us pursuant to the Debenture Offer, we will have the right to redeem all of the remaining Debentures of that series at the applicable Debenture Offer Price. Notice of such redemption must be given by us to the Debenture Trustee within 10 days following the expiry of the Debenture Offer, and as soon as possible thereafter, by the Debenture Trustee to the holders of the applicable series of Debentures not tendered pursuant to the Debenture Offer.

In addition, in the event of a Change of Control, we may redeem the Initial Debentures, at our option and for cash only, prior to March 31, 2028, at a cash redemption price equal to 103.875% of the principal amount of the Initial Debentures plus an aggregate amount equal to the interest that (i) has accrued and is unpaid to such date of redemption; and (ii) would have accrued and been payable up to and including March 31, 2028 had the Initial Debentures not been redeemed. We may also redeem the Second Series Debentures in the event of a Change of Control, at our option and for cash only, prior to September 30, 2028, at a cash redemption price equal to 104.125% of the principal amount of the Second Series Debentures plus an aggregate amount equal to the interest that (i) has accrued and is unpaid to such date of redemption; and (ii) would have accrued and been payable up to and including September 30, 2028 had the Second Series Debentures not been redeemed.

Method of Payment

Payment of Principal on Redemption or at Maturity

On redemption or at maturity of the Debentures, we will repay the indebtedness represented by the Debentures by paying to the Debenture Trustee in lawful money of Canada an amount equal to the principal amount of the outstanding Debentures, together with any accrued and unpaid interest thereon. We may, at our option, on not more than 60 days' and not less than 40 days' prior notice, subject to applicable regulatory approval (including the approval of the Toronto Stock Exchange) and provided no Event of Default (as such term is defined below) has occurred and is continuing, elect to satisfy our obligation to repay all or any portion of the principal amount of and premium (if any) on the Debentures that are to be redeemed or that are to mature, by issuing and delivering to the holders thereof that number of freely tradeable Common Shares determined by dividing the principal amount of the Debentures being repaid by 95% of the Current Market Price on the date of redemption or maturity, as applicable (the "**Common Share Payment Right**"). In such circumstances, any accrued and unpaid interest will be payable in cash (subject to the Common Share Interest Payment Election described below). No fractional Common Shares will be issued on redemption or at maturity but in lieu thereof we will satisfy fractional interests by a cash payment equal to the Current Market Price of the fractional interest less any taxes required to be deducted or withheld.

Under the Debenture Indenture "**Current Market Price**" means the arithmetic average of the volume-weighted average trading price per Common Share for the 20 consecutive trading days ending on the fifth trading day preceding the date of determination on the Toronto Stock Exchange (or, if the Common Shares are not listed on the Toronto Stock Exchange, on such stock exchange on which the Common Shares are listed as may be selected for such purpose by the Board of Directors and approved by the Debenture Trustee, or if the Common Shares are not listed on any stock exchange, then on the over-the-counter market). The volume weighted average trading price shall be determined by dividing the aggregate sale price of all Common Shares sold on the said exchange or market, as the case may be, during the said 20 consecutive trading days by the total number of Common Shares so sold.

Under the Debenture Indenture, we shall not, directly or indirectly (through a subsidiary or otherwise) undertake or announce any rights offering, issuance of securities, subdivision of the Common Shares, dividend or other distribution on the Common Shares or any other securities, capital reorganization, reclassification or any similar type of transaction in which:

(a) the number of securities to be issued;

(b) the price at which securities are to be issued, converted or exchanged; or

(c) any property or cash that is to be distributed or allocated,

is in whole or in part based upon, determined in reference to, related to or a function of, directly or indirectly, (i) the exercise or potential exercise of the Common Share Payment Right on redemption or maturity of the Debentures, or (ii) the Current Market Price determined in connection with the exercise or potential exercise of the Common Share Payment Right on redemption or maturity of the Debentures.

The Debentures are not convertible into Common Shares at the option of the holders of the Debentures at any time.

Interest Payment Election

We may elect, subject to regulatory approval (including the approval of the Toronto Stock Exchange) and provided that no Event of Default has occurred and is continuing, from time to time to satisfy our obligation to pay all or any part of the interest on the Debentures (the "**Interest Obligation**"), on the date it is payable under the Debenture Indenture (an "**Interest Payment Date**"), by issuing and delivering a sufficient number of freely tradable Common Shares to the Debenture Trustee for sale to satisfy all or any part, as the case may be, of the Interest Obligation in accordance with the Debenture Indenture (the "**Common Share Interest Payment Election**"). The Debenture Indenture provides that, upon such election, the Debenture Trustee shall have the power to (a) accept delivery of the Common Shares from us and process the Common Shares in accordance with the Common Share Interest Payment Election notice, delivered in accordance with the Debenture Indenture; (b) deliver such Common Shares on behalf of us, as we shall direct in our absolute discretion through the investment banks, brokers or dealers identified by us in the Common Share Interest Payment Election Notice at the price identified therein (which may be the market price from time to time or based thereon); (c) invest the proceeds of such sales on our direction in securities issued or guaranteed by the Government of Canada or any province thereof which mature prior to an applicable Interest Payment Date; (d) use such proceeds, together with proceeds from the sale of Common Shares not invested as aforesaid, to pay the Interest Obligation in respect of which the Common Share Interest Payment Election was made; (e) deliver proceeds to holders of Debentures to satisfy all or a portion of the our Interest Obligations, as directed by us in the Common Share Interest Payment Election Notice; and (f) perform any other action necessarily incidental thereto as directed by us in our absolute discretion with the consent of the Debenture Trustee.

The Debenture Indenture sets forth the procedures to be followed by us and the Debenture Trustee in order to effect the Common Share Interest Payment Election. Neither our making of the Common Share Interest Payment Election nor the consummation of sales of Common Shares will (a) result in the holders of the Debentures not being entitled to receive on the applicable Interest Payment Date cash in an aggregate amount equal to the interest payable on such Interest Payment Date, or (b) entitle such holders to receive any Common Shares in satisfaction of the Interest Obligation.

Events of Default

The Debenture Indenture provides that an event of default ("**Event of Default**") in respect of the Debentures will occur if any one or more of the following described events has occurred and is continuing with respect to such Debentures: (a) failure for 15 days to pay interest on the Debentures when due; (b) failure to pay principal or premium, if any, on the Debentures when due whether at maturity, upon redemption, by declaration or otherwise; (c) default in the observance of our covenant relating to maintaining listing of the Common Shares and Debentures on the Toronto Stock Exchange, and to maintaining our status as a "reporting issuer", which defaults continue for 10 business days; (d) a default in performing or observing any of our covenants, agreements or obligations described in the Debenture Indenture and the continuance of such default for 30 days after written notice to us by the Debenture Trustee or by the holders of not less than 25% in principal amount of outstanding Debentures requiring the same to be remedied; (e) the failure of us to (i) make a Debenture Offer within 30 days of the occurrence of a Change of Control, or (ii) take up and pay for, within the time period set out in the Debenture Indenture, any Debentures then outstanding and tendered by any Debentureholders in acceptance of the Debenture Offer; (f) if a decree or order of a Court having jurisdiction is entered adjudging us or any of our material subsidiaries bankrupt or insolvent under the *Bankruptcy and Insolvency Act* (Canada) or any other bankruptcy, insolvency or analogous laws, or issuing sequestration or process of execution against, or against any substantial part of, the property of us or any of our material subsidiaries, or appointing a receiver of, or of any substantial part of, the property of us or any of our material subsidiaries or ordering the winding-up or liquidation of its or their affairs, and any such decree or order continues unstayed and in effect for a period of 60 days; (g) if we or any of our material subsidiaries institutes proceedings to be adjudicated bankrupt or insolvent, or consents to the institution of bankruptcy or insolvency proceedings against it under the *Bankruptcy and Insolvency Act* (Canada) or any other bankruptcy, insolvency or analogous laws, or consents to the filing of any such petition or to the appointment of a receiver of, or of any substantial part of, the property of us or any of our material subsidiaries or makes a general assignment for the benefit of creditors, or admits in writing its inability to pay its debts generally as they become due; (h) any substantial part of our property or any of our material subsidiaries shall be sequestered or attached and shall not be returned to our possession or such material subsidiary or released from such attachment, as the case may be, whether by filing of a bond, or stay or otherwise, within 60 consecutive days thereafter; (i) if a resolution is passed for the winding-up or liquidation of us or any of our material subsidiaries except in the course of carrying out or pursuant to a transaction in respect of which the conditions set out in the terms of the Debentures are duly observed and performed; (j) if any proceedings with respect to us or any of our material subsidiaries are taken with respect to a compromise or arrangement, with respect to our creditors generally, under the applicable legislation of any jurisdiction; (k) default in the delivery, when due, of any Common Shares, which default continues for 15 days; and (l) cross acceleration to indebtedness subordinated or *pari passu* to the Debentures, subject to a $25 million threshold.

If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion (subject to waiver thereof by the Debentureholders), and will upon request of holders of not less than 25% of the principal amount of the Debentures then outstanding, declare the principal of and interest on all outstanding Debentures to be immediately due and payable. In certain cases, the holders of more than 50% of the principal amount of such Debentures then outstanding may, on behalf of the holders of all such Debentures, waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders may prescribe.

The Debentures Indenture also provides that for default purposes, where the Event of Default refers to an Event of Default with respect to a particular series of Debentures, then references to the Debentures shall mean Debentures of the particular series and references to the Debentureholders shall refer to the Debentureholders of the particular series, as applicable.

Consolidation, Mergers or Sales of Assets

The Debenture Indenture provides that we may not, without the consent of the holders of the Debentures, consolidate or amalgamate with or merge into any person (other than a direct or indirect wholly-owned subsidiary of us) or sell, convey, transfer or lease (excluding any form of sale and leaseback transaction that provides for the sale or transfer of real property that is then rented or leased back to us or a subsidiary) all or substantially all of our properties and assets to another person (other than a direct or indirect wholly-owned subsidiary of us) unless: (a) the successor (if other than us) assumes all of our obligations under the Debenture Indenture in respect of the Debentures; (b) no condition or event shall exist as to us (at the time of such transaction) or the successor (immediately after such transaction) and after giving full effect thereto or immediately after the successor shall become liable to pay the principal monies, premium, if any, interest and other monies due or which may become due under the Debenture Indenture, which constitutes or would constitute an Event of Default under the Debenture Indenture; and (c) other conditions described in the Debenture Indenture are met.

Upon the assumption of our obligations by such entity in such circumstances, subject to certain exceptions, we shall be discharged from all obligations under the Debentures and the Debenture Indenture. Although such transactions are permitted under the Debenture Indenture, certain of the foregoing transactions occurring could constitute a Change of Control of us, which would require us to offer to purchase the Debentures as described above. An assumption of our obligations under the Debentures and the Debenture Indenture by such entity might be deemed for Canadian federal income tax purposes to be an exchange of the Debentures for new debentures by the holders thereof, resulting in recognition of gain or loss for such purposes and possibly other adverse tax consequences to the holders. Holders should consult their own tax advisors regarding the tax consequences of such an assumption.

Non-Financial Covenants

The Debenture Indenture contains covenants of us to: (a) pay principal, premium (if any) and interest; (b) pay the Debenture Trustee's remuneration; (c) notify the Debenture Trustee immediately upon obtaining knowledge of any Event of Default that is continuing; (d) subject to the express provisions of the Debenture Indenture, carry on and conduct our activities, and cause our subsidiaries to carry on and conduct their businesses, in a business-like manner and in accordance with good business practices, and, subject to the provisions of the Debenture Indenture, do or cause to be done all things necessary to preserve and keep in full force and effect our existence and rights; (e) keep proper books of record and account; (f) deliver to the Debenture Trustee, within 120 days of each year end, an officer's certificate as to our compliance with all conditions and covenants in the Debenture Indenture; (g) if we fail to perform any of our covenants contained in the Debenture Indenture, the Debenture Trustee may notify the holders of Debentures of such failure on our part or may itself perform any of the covenants capable of being performed by it; (h) use reasonable commercial efforts to maintain the listing of the Common Shares and the Debentures on the Toronto Stock Exchange, and to maintain our status as a "reporting issuer" not in default of the requirements of applicable securities legislation (provided that the foregoing shall not prevent or restrict us from carrying out a transaction described above under "– *Consolidation, Mergers or Sales of Assets*" so long as such transaction is carried out in accordance with the Debenture Indenture, including in connection with a Change of Control as further described under "— *Change of Control*", even if as a result of such transaction we cease to be a "reporting issuer" in or the Common Shares or Debentures cease to be listed on the Toronto Stock Exchange or any other stock exchange); and (i) not declare or pay any distributions to the holders of our issued and outstanding Common Shares after the occurrence of an Event of Default unless and until such Event of Default shall have been cured or waived or shall have ceased to exist.

Purchase for Cancellation

We may at any time purchase the Debentures in the open market, by tender, by private contract or otherwise, subject to regulatory requirements and compliance with the Credit Facility or other Senior Secured Indebtedness.

Any Debenture purchased by us will be surrendered to the Debenture Trustee for cancellation. Any Debentures surrendered to the Debenture Trustee may not be reissued or resold and will be cancelled promptly.

Modification

The rights of the holders of the Debentures, as well as any other series of debentures that may be issued under the Debenture Indenture, may be modified in accordance with the terms of the Debenture Indenture. For that purpose, among others, the Debenture Indenture contains certain provisions which make binding on all Debentureholders resolutions passed at meetings of the holders of Debentures by votes cast thereat by holders of not less than 66⅔% of the principal amount of the Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66⅔% of the principal amount of the Debentures then outstanding. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of Debentures of each particularly affected series.

We and the Debenture Trustee may, without the consent or concurrence of the holders of debentures under the Debenture Indenture, by supplemental indenture or otherwise, make any changes or corrections in the Debenture Indenture which we and the Debenture Trustee have been advised by counsel are required for the purpose of curing or correcting any ambiguity or defective or inconsistent provisions or clerical omissions or mistakes or manifest errors contained therein or in any indenture supplemental thereto.

Governing Law

Each of the Debenture Indenture and the Debentures are governed by, and will be construed in accordance with, the laws of the Province of Alberta.

Stability Rating

We have not asked for or received a stability rating, and we are not aware that we have received any other kind of rating, including a provisional rating, from one or more approved rating organizations for the Debentures.

MARKET FOR OUR SECURITIES

Trading Prices and Volumes

Our Common Shares trade on the Toronto Stock Exchange under the trading symbol "CJ" and commenced trading on the Toronto Stock Exchange on December 17, 2013. The following table sets out the high and low trading prices and aggregate volume of trading for the periods noted below for our Common Shares, as reported by the Toronto Stock Exchange.

PERIOD	HIGH	LOW	VOLUME
2024			
January	6.52	6.15	11,220,364
February	6.91	6.01	11,239,558
March	7.14	6.57	8,670,455
April	7.38	6.81	15,702,972
May	7.11	6.74	14,769,681
June	7.05	6.45	12,588,916
July	7.12	6.57	12,999,756
August	7.19	6.35	18,465,556
September	6.78	6.18	15,239,359
October	6.70	6.32	14,243,241
November	6.77	6.16	14,108,879
December	6.57	5.98	14,199,687
2025			
January	6.97	6.315	15,794,228
February	6.64	6.10	12,148,939
March (to March 26)	6.69	5.905	11,847,763

Our Initial Debentures trade on the Toronto Stock Exchange (in increments of $100) under the trading symbol "CJ.DB" and commenced trading on the Toronto Stock Exchange on January 3, 2025. The following table sets out the high and low trading prices and aggregate volume of trading for the periods noted below for the Initial Debentures, as reported by the Toronto Stock Exchange.

PERIOD	HIGH	LOW	VOLUME
2025			
January (from Jan. 3)	100.10	97.51	8,574,000
February	100.50	98.00	2,735,000
March (to March 26)	99.38	96.30	1,179,000

Our Second Series Debentures trade on the Toronto Stock Exchange (in increments of $100) under the trading symbol "CJ.DB.A" and commenced trading on the Toronto Stock Exchange on March 4, 2025. The following table sets out the high and low trading prices and aggregate volume of trading for the periods noted below for the Second Series Debentures, as reported by the Toronto Stock Exchange.

PERIOD	HIGH	LOW	VOLUME
2025			
March 4 to March 26	99.70	98.00	5,778,000

Our Warrants trade on the Toronto Stock Exchange under the trading symbol "CJ.WT" and commenced trading on the Toronto Stock Exchange on January 3, 2025. The following table sets out the high and low trading prices and aggregate volume of trading for the periods noted below for our Warrants, as reported by the Toronto Stock Exchange.

PERIOD	HIGH	LOW	VOLUME
2025			
January (from Jan. 3)	0.85	0.30	463,090
February	0.64	0.46	143,306
March (to March 26)	0.64	0.375	243,848

Prior Sales

During the year ended December 31, 2024 we granted a total of 1.5 million performance and restricted awards pursuant to our bonus award incentive plan. On the payment date of the bonus awards, we have the sole discretion as to whether the bonus awards are paid in cash, Common Shares from treasury or Common Shares purchased on the market. No other share-based compensation was granted by us during the year ended December 31, 2024. See note 14 of our annual financial statements for the year ended December 31, 2024 for further information.

DIRECTORS AND OFFICERS

Summary Information

The following table sets forth certain summary information in respect of our directors and executive officers as at the date of this Annual Information Form.

NAME, PROVINCE AND COUNTRY OF RESIDENCE	POSITION HELD	PRINCIPAL OCCUPATION FOR THE LAST FIVE YEARS	DIRECTOR SINCE
M. Scott Ratushny [(3)] Alberta, Canada	Chief Executive Officer and Chair	Our Chair and Chief Executive Officer since July 6, 2012. Prior thereto, Chair and Chief Executive Officer of Midway Energy Ltd., a public oil and gas company.	May 2011
Stephanie Sterling [(1)(2)(3)(4)(5)] Alberta, Canada	Lead Director	Lead Independent director. Ms. Sterling is a retired senior executive with Shell Canada with over 25 years' experience. Ms. Sterling has also been a director of the Alberta Petroleum Marketing Commission, a Crown board, since July 2017 and a director of Cabin Ridge Project Limited, a private coal mining company, since April, 2020. She previously served on the board of Riversdale Resources Limited, a private coal development company from 2017 to 2019.	August 2017
John A. Brussa [(2)(4)(5)] Alberta, Canada	Director	Mr. Brussa is a partner and Chair of Burnet, Duckworth & Palmer LLP.	July 2012
John Festival [(1)(3)(4)(5)] Alberta, Canada	Director	Independent Businessperson. Mr. Festival brings over 35 years of experience in the oil and gas industry with a strong background in thermal oil projects and a track record for creating shareholder value. Mr. Festival is currently President and CEO of Broadview Energy, a private corporation with heavy oil assets in Alberta and Saskatchewan and was previously President & CEO of BlackPearl Resources Inc. from 2009 to 2018, and President & CEO of BlackRock Ventures Inc. from 2001 to 2006. Mr. Festival is currently a director of Advantage Energy Ltd. and Athabasca Oil Corporation.	November 2023

NAME, PROVINCE AND COUNTRY OF RESIDENCE	POSITION HELD	PRINCIPAL OCCUPATION FOR THE LAST FIVE YEARS	DIRECTOR SINCE
John Gordon (1)(2) Alberta, Canada	Director	Mr. Gordon served as the Canadian Managing Partner, Quality and Risk Management, the Canadian Managing Partner, Audit and the Calgary Office Managing Partner for KPMG LLP prior to his retirement in 2018. Mr. Gordon has extensive experience in providing audit and other services to public oil and gas companies. Mr. Gordon is a Chartered Professional Accountant (FCPA), a Chartered Financial Analyst (CFA) charter holder, and is a graduate of the University of Saskatchewan. Mr. Gordon serves on the Board of Topaz Energy Corporation, the CAMH Foundation, and the University of Calgary Properties Group and is a lecturer for, and an active member of the Institute of Corporate Directors.	May 2021
Dale Orton Alberta, Canada	Chief Operating Officer	Our Chief Operating Officer since November 9, 2017. Prior thereto, our Vice President since December 1, 2016. Prior thereto, Senior Vice President, Development for Long Run Exploration Ltd., a public oil and gas company.	N/A
Shawn Van Spankeren Alberta, Canada	Chief Financial Officer	Our Chief Financial Officer since January 15, 2018. Prior thereto Vice President, Finance and Administration, Crew Energy Inc. since October 2013. Prior thereto, Vice President, Finance & Controller, Crew Energy Inc. since January 2009.	N/A
Robert Wollmann Alberta, Canada	Senior Vice President, Exploration	Our Senior Vice President Exploration since November, 2017. Prior thereto, President, Long Run Exploration Ltd since April 2017. Prior thereto, President & CEO, Twin Butte Energy Ltd. since May 2014. Prior thereto, Senior Vice President, Exploration, Penn West Petroleum Ltd. since February 2012.	N/A
Laurence Broos Alberta, Canada	Vice President, Finance	Our Vice President, Finance since February 10, 2015. Prior thereto, Treasurer of Penn West Petroleum Ltd.	N/A
Connie Shevkenek Alberta, Canada	Vice President, Engineering	Our Vice President, Engineering since September 1, 2016. Prior thereto, our Manager of Engineering since February, 2014. Prior thereto, Vice President of Business Development at Flagstone Energy Inc.	N/A
Jason LaForge Alberta, Canada	Vice President, Central	Our Vice President, Central since November 9, 2017. Prior thereto, our area manager of the Central area since September, 2017. Prior thereto, Vice President Operations at Muirfield Resources Ltd.	N/A
Ken Younger Alberta, Canada	Vice President, South	Our Vice President, South since March 2018. Prior thereto, our area manager of the South area since April 2016. Prior thereto, Manager of Production at Spur Resources Ltd. since August, 2010.	N/A
David Kelly Alberta, Canada	Vice President, Saskatchewan	Our Vice President, Saskatchewan since September 2017. Prior thereto, Vice President, Production & Operations at Gain Energy Ltd. and Omers Energy Inc. since February 2017. Prior thereto, Production Manager with Omers Energy Inc. since June 2015.	N/A

Notes:

(1) Member of our Audit Committee. Mr. John Gordon is the Chair of the Audit Committee.
(2) Member of our Corporate Governance and Compensation Committee. Ms. Stephanie Sterling is the Chair of the Corporate Governance and Compensation Committee.
(3) Member of the Reserves Committee. Mr. John Festival is the Chair of the Reserves Committee.
(4) Member of our Environmental, Social and Governance Committee. Ms. Stephanie Sterling is the Chair of the Environmental, Social and Governance Committee.
(5) Independent director.

All of our directors' terms of office will expire at the earliest of their resignation, the close of the next annual shareholder meeting called for the election of directors, or on such other date as they may be removed according to the *Business Corporations Act* (Alberta). Each director will devote the amount of time as is required to fulfill his or her obligations to us. Our officers are appointed by and serve at the discretion of the Board of Directors.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as discussed below, and to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Other than as discussed below, to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially our control: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) 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; or (b) has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

Messrs. Brussa and Ratushny were directors of Enseco Energy Services Corp. ("**Enseco**"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Messrs. Brussa and Ratushny resigned as directors of Enseco on October 14, 2015. On December 21, 2015 Enseco was assigned into bankruptcy by the receiver.

Mr. Brussa was a director of Argent Energy Ltd. which was the administrator of Argent Energy Trust. On February 17, 2016, Argent Trust and its Canadian and United States holding companies (collectively "**Argent**") commenced proceedings under the *Companies' Creditors Arrangement Act* (Canada) for a stay of proceedings until March 19, 2016. On the same date, Argent filed voluntary petitions for relief under Chapter 15 of the *United States Bankruptcy Code*. On March 9, 2016, the stay of proceedings under the *Companies' Creditors Arrangement Act* (Canada) was extended until May 17, 2016. Additionally on March 10, 2016 the U.S. Bankruptcy Court approved an order recognizing the *Companies' Creditors Arrangement Act* (Canada) as the foreign main proceedings under Chapter 15 of the *United States Bankruptcy Code*. Mr. Brussa resigned on June 30, 2016.

Mr. Brussa resigned as a director on September 1, 2016 and Mr. Wollmann departed as President and CEO of Twin Butte Energy Ltd. ("**Twin Butte**"), a public oil and gas company, on September 2, 2016. On September 1, 2016, the senior lenders of Twin Butte (the "**Senior Lenders**") made an application to the Court of Queen's Bench of Alberta ("**Court**") to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Twin Butte was suspended by the Toronto Stock Exchange. On September 1, 2016, the Senior Lenders were granted a receivership order by the Court.

Mr. Brussa was a director of Virginia Hills Oil Corp. ("**VHO**"), a public oil and gas company. On February 13, 2017, VHO received a demand notice and notice of intention to enforce security from its lenders and agreed to consent to the early enforcement of the lenders' security and the appointment of a receiver over all of the current and future assets, undertakings and properties of VHO. The receiver was appointed on February 13, 2017. Mr. Brussa resigned as a director of VHO on February 24, 2017.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially our control has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

On June 30, 2005 the United States Securities and Exchange Commission ("**SEC**") issued a settlement order relating to certain administrative proceedings involving a number of parties including KPMG LLP and Mr. Gordon, a former partner of KPMG LLP. The SEC alleged that during the years 1999 to 2002, Mr. Gordon, while a partner at KPMG LLP, knew, in his role as concurring and reviewing audit partner, that certain accounting services were being provided by KPMG LLP to an SEC registrant, while KPMG LLP were also serving as auditors to the same registrant. KPMG received $60,148 in aggregate fees from the audit and bookkeeping services it performed for this registrant during this period. Under the terms of the settlement with the SEC, Mr. Gordon agreed not to appear or practice as an accountant before the SEC, with respect to SEC registrants, for a period of nine months, after which time, he was automatically reinstated.

Conflicts of Interest

Certain of our officers and directors are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to our best interests. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the *Business Corporations Act* (Alberta). The *Business Corporations Act* (Alberta) provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his or her interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE

Audit Committee Mandate

The Board has adopted a written mandate and terms of reference for our Audit Committee, which sets out the Audit Committee's responsibility for, among other things, reviewing our financial statements and our public disclosure documents containing financial information and reporting on such review to the Board, ensuring our compliance with legal and regulatory requirements, overseeing qualifications, engagement, compensation, performance and independence of our external auditors, and reviewing, evaluating and approving the internal control and risk management systems that are implemented and maintained by management. A copy of the Audit Committee mandate is attached to this Annual Information Form as Appendix C.

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee currently consists of John Gordon (Chair), John Festival and Stephanie Sterling. Each of the members of the Audit Committee is considered "financially literate" and "independent" within the meaning of National Instrument 52-110 – *Audit Committees*.

We believe that each of the members of our Audit Committee possesses: (a) an understanding of the accounting principles used by us to prepare financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and reserves; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by our financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting. The relevant education and experience of each Audit Committee member is outlined below.

John Gordon:

Mr. Gordon served as the Canadian Managing Partner, Quality and Risk Management, the Canadian Managing Partner, Audit and the Calgary Office Managing Partner for KPMG LLP prior to his retirement in 2018. Mr. Gordon has extensive experience in providing audit and other services to public oil and gas companies. Mr. Gordon is a Chartered Professional Accountant (FCPA), a Chartered Financial Analyst (CFA) charter holder, and is a graduate of the University of Saskatchewan.

John Festival:

Mr. Festival graduated from the University of Saskatchewan with a Bachelor of Science in Chemical Engineering and brings over 35 years of experience in the oil and gas industry with a strong background in thermal oil projects and a track record for creating shareholder value. Mr. Festival started his career at Home Oil Company and worked in Lloydminster as an engineer at the Kitscoty Cyclic Steam Project. He then joined Koch Exploration Canada ("**Koch**") and alongside a technical team established operations across all the heavy oil regions of Western Canada. At the time, Koch was the largest lease holder in the Alberta oil sands, including operatorship of the Fort Hills mine asset. Mr. Festival and the senior technical team from Koch moved on to BlackRock Ventures Inc. ("**BlackRock**") in 2001 where they discovered primary heavy oil in the Seal area of Alberta. They also piloted and initiated the Orion SAGD Project, one of the first SAGD projects in the Clearwater zone which continues to operate today. After selling BlackRock to Shell for $2.6 billion in 2006, his team went on to transform BlackPearl Resources Inc. ("**BlackPearl**") into a thermal heavy oil player at Onion Lake, Saskatchewan. At BlackPearl, they also piloted the Blackrod SAGD Project in Alberta and then merged with International Petroleum Corp in 2019. In 2019, Mr. Festival was appointed CEO of Broadview Energy, a private Saskatchewan thermal development company. Mr. Festival also serves on the board of Advantage Energy Ltd. and Athabasca Oil Corporation.

Stephanie Sterling:

Ms. Sterling holds a Bachelor of Science (Mechanical Engineering) degree and an MBA from the University of Alberta. Ms. Sterling is a recently retired senior executive with Shell Canada with over 25 years' experience in engineering, large project start-up and operations, governance, joint venture negotiations and relationships, risk management, business development and strategic planning. She has served as General Manager for Non-Technical Risk Integration, Community and Indigenous Relations for Shell in Canada, USA and Latin America where she was responsible for integrating risk management into new projects. She also served as the Vice President Business and Joint Ventures for Shell's Heavy Oil business, where she was responsible for the joint venture governance, commercial negotiations and relationships for two significant joint ventures: the Athabasca Oil Sands Project among Shell, Chevron and Marathon; and the AERA Energy LLC joint venture in California between Shell and Exxon. Ms. Sterling also serves on the board of the Alberta Petroleum Marketing Commission, including as Chair of the Audit Committee and Cabin Ridge Project Limited, a private coal mining company and previously served on the board and Audit Committee of Riversdale Resources Inc. from 2017 to 2019.

Pre-Approval Policies and Procedures for the Engagement of Non-Audit Services

The Audit Committee must pre-approve all non-audit services to be provided to us by our external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Audit Service Fees

The following table summarizes the fees paid by us to our auditors, KPMG LLP, for external audit and other services during the period indicated.

YEAR	AUDIT FEES (1) ($)	AUDIT-RELATED FEES (2) ($)	TAX FEES (3) ($)	ALL OTHER FEES (4) ($)
2023	353,100	96,300	4,280	-
2024	363,000	97,200	12,530	64,200

Notes:

(1) Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(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 our financial statements and are not reported as audit fees.

(3) Tax fees include tax compliance, tax advice, tax planning and compilation of tax returns.

(4) All other fees relate to the filing of our base shelf prospectus.

DIVIDEND POLICY

We started paying dividends on our Common Shares in 2014. We carefully monitor the impact of all issues affecting our business and the necessity to adjust our monthly dividends and our capital programs as conditions evolve and on March 17, 2020, we suspended our dividend due to the economic environment. On May 12, 2022, we announced that our Board of Directors had approved the reinstatement of our monthly dividend starting at $0.05 per Common Share per month in June 2022. On September 12, 2022, we announced that our Board of Directors had approved an increase in our monthly dividend commencing in the fourth quarter of 2022 from $0.05 per Common Share to $0.06 per Common Share. See "*General Development of our Business – History and Development – Developments in 2022*".

Our long-term objective with respect to dividends is to set a dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to maintain or modestly grow our production base.

Cash dividends were paid on the 15th day (or if such date was not a business day, on the next business day) following the end of each calendar month to Shareholders of record on the last business day of each such calendar month or such other date as determined from time to time by us.

The payment and amount of dividends is determined in the sole discretion of our Board after considering a variety of factors and conditions existing from time to time, including current and future commodity prices, foreign exchange rates, our hedging program, current operations including production levels, operating costs, royalty burdens and debt service requirements, available investment opportunities and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends.

The following monthly cash dividends on our Common Shares were declared by our Board for the periods indicated:

PERIOD	DIVIDEND PER COMMON SHARE
September 2014 – December 2015	$0.07
January 2016 – December 2018	$0.035
January 2019 – June 2019	$0.01
July 2019 – February 2020	$0.015
March 2020 – May, 2022	Suspended
June 2022 – September, 2022	$0.05
October 2022 – March, 2025	$0.06

Unless otherwise specified, all dividends paid by us are designated as "eligible dividends" under the *Income Tax Act* (Canada).

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that, among other things, no default, event of default or borrowing base shortfall exists, could reasonably be expected to result from, such declaration or payment.

INDUSTRY CONDITIONS

Companies operating in the Canadian oil and gas industry are subject to extensive regulation and control of operations (including with respect 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 as well as with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Western Canadian oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments governments may enact in the future.

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

The discussion below outlines some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the provinces of Alberta, Saskatchewan and British Columbia, where our assets are primarily located. While these matters do not affect our operations in any manner that is materially different than the manner in which they affect other similarly sized industry participants with similar assets and operations, investors should consider such matters carefully.

Pricing and Marketing in Canada

The price of crude oil, natural gas, and NGLs is negotiated by buyers and sellers. A number of factors may influence prices, including (global, in some instances) supply and demand, quality of product, distance to market, availability of transportation, value of refined products, prices of competing products, price of competing stock, contract term, weather conditions, supply/demand balance and contractual terms of sale.

Transportation Constraints and Market Access

Capacity to transport production from Western Canada to Eastern Canada, the United States and other international markets has been, and continues to be, a major constraint on the exportation of crude oil, natural gas and NGLs. Many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and socio-political factors. Due in part to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Exports of Crude Oil, Natural Gas and NGL from Canada

On February 1, 2025, U.S. President Donald Trump signed an executive order imposing tariffs of 25% on almost all goods imported from Canada, with a lower tariff of 10% imposed on Canadian energy and resources products including crude oil, natural gas, lease condensates, natural gas liquids and refined petroleum. These tariffs are expected to affect the pricing structure for natural gas, crude oil and related products exported from Canada to the United States and alter the competitiveness of and market for Canadian oil and natural gas imports into the United States. In response, the Department of Finance Canada announced countermeasures with the imposition of 25% tariffs on certain goods imported from the U.S. On February 3, 2025, it was announced that the implementation of such announced tariffs would be suspended for 30 days. On March 4, 2025, the tariffs came into effect as initially promulgated, however some of such tariffs were paused on March 6, 2025, purportedly until April 2, 2025. Furthermore, on March 12, 2025 the U.S. imposed a 25% tariff on all steel and aluminum imports into the United States and the following day Canada imposed a 25% counter-tariff on $29.8 billion in products imported into Canada from the United States. There remains substantial ambiguity regarding whether the paused tariffs will become effective again in the future, and if they do, whether they will remain in place. Additionally, the precise effect of the tariffs on the Canadian economy and Canadian energy producers is yet to be determined, but it is expected to have an adverse effect if the tariffs are maintained.

Oil Pipelines

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

Producers negotiate with pipeline operators to transport their products to market on a firm 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.

Specific Pipeline Updates

Construction of the Trans Mountain Pipeline expansion, which received Cabinet approval in November 2016, was completed in April 2024, and service began in May 2024. The original pipeline and the newly completed expansion now operate collectively. With the expansion completed, the system's nominal capacity increased from approximately 300,000 to 890,000 barrels per day, and the expansion included three new berths at Westridge Marine Terminal in British Columbia.

Natural Gas and Liquefied Natural Gas ("LNG")

Natural gas prices in Western Canada have been constrained in recent years, reaching record lows in 2024, due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which is generally lower than the prices received in other North American markets.

In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "**NGTL System**"). The NGTL system is in the midst of implementing a $9.9 billion infrastructure program to add 3.58 billion cubic feet per day of capacity between 2022 and 2024. 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.

In January 2024, Shell plc signed a deal to purchase LNG from a floating export facility to serve the Asian energy markets, which is a 20-year deal which calls for 2 million metric tons of LNG per year over the course of the agreement.

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LNG Export Terminal Updates

There are currently seven LNG export projects at different stages of development in British Columbia, the majority of which are targeting beginning operations between 2027 and 2030. The LNG Canada export terminal located in Kitimat, BC will be Canada's first large-scale LNG export facility to begin operations. In October 2018, the joint venture partners of LNG Canada announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the CGL Pipeline. Phase 1 of the LNG Canada project is over 95% complete and the facility is on track to deliver first cargoes by the middle of 2025. LNG Canada eventually plans to double the facility's capacity with a proposed Phase 2 expansion. Construction of the Woodfibre LNG project, located near Squamish, British Columbia, began in the fall of 2023 and substantial completion of the project expected in 2027. Additionally, in June 2024, the proposed Cedar LNG project, a floating LNG facility also located in British Columbia, reached a successful final investment decision, and is expected to be in service in late 2028. Western LNG is also advancing the Ksi Lisims LNG project, a proposed floating LNG facility located near the Nisga'a Nation in northern British Columbia. The project is being developed in partnership with the Nisga'a Nation and Rockies LNG, with the goal of delivering low-carbon LNG to global markets. The proposed facility is designed to produce approximately 12 million tonnes per year of LNG and is expected to utilize hydroelectric power to minimize emissions. If approved, Ksi Lisims LNG could commence operations by the early 2030s, contributing to British Columbia's growing role in the global LNG market. LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

Land Tenure

Mineral Rights

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

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

An additional category of mineral rights ownership is Canadian federal government ownership of mineral rights on Indian reserves (as designated under the *Indian Act*), which is managed and regulated by a separate government body according to distinct legislation. We do not have operations on Indigenous reserves.

Surface Rights

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

Royalties and Incentives

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. Provincial royalty regimes operate in conjunction with applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable. 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 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 government and provincial governments create incentive programs for businesses operating in specific industries, including those in the oil and gas industry. These are often introduced when commodity prices are low to encourage exploration and development activity, and may provide for 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 or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

Regulatory Authorities and Environmental Regulation

The Canadian oil and gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and greenhouse gas ("**GHG**") emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry. Companies that have hydraulic fracturing operations have additional operational regulatory and reporting requirements.

Liability Management

Alberta

The Alberta Energy Regulator (the "**AER**") administers several liability management programs to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The province is gradually moving from a prescriptive framework toward a more holistic approach to liability management.

Alberta has an orphan fund to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in certain of the AER's programs if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The orphan fund is funded through a levy and a loan from the provincial government. In March 2024, the Alberta government approved a $135 million levy to fund the Orphan Well Association's 2024/25 operating budget.

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "Redwater" decision), provides the backdrop for Alberta's approach to liability management. As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a licence transfer when any such licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. The responsibility of the abandonment and reclamation operations of a defunct licensee may fall to the defunct licensee's working interest partners or can be applied for a working interest partnership agreement with the Orphan Well Association ("**OWA**"). Cost reimbursement of the defunct licensee is possible through the orphan fund. The AER may also order the OWA to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure.

British Columbia

Similar to Alberta, the British Columbia regulator has moved away from the formulaic approach to liability management toward a more holistic assessment of a permit holder's ability to meet its abandonment and reclamation obligations. Additionally, similar to Alberta's orphan fund, British Columbia and Saskatchewan have programs to address the abandonment and reclamation costs for orphan sites

The British Columbia Dormancy and Shutdown Regulation establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that have become dormant between 2019 and 2023 and became or will become dormant during or after 2024.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"), designed to manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to Saskatchewan's orphan fund. The orphan fund carries out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when there is no legally responsible or financially able party to manage abandonment and reclamation liabilities associated with a licensee's wells and facilities. The SK LLR Program also outlines requirements for security deposits and licence transfers, including assessments and other transfer due diligence. On January 1, 2023, Saskatchewan enacted the *Financial Security and Site Closure Regulations*, which includes: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. The *Oil and Gas Conservation Regulations, 2012*, also updated in January 2023, provide, among other things, a formula for determining a licensee's liability rating, eligibility requirements for holding licences, and guidance on when a security deposit may be required by a licensee or in connection with a transfer.

Climate Change Regulation

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

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. In 2016, 195 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. In 2016, Canada ratified the Paris Agreement and committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40–45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference Canada pledged to (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) cease to export thermal coal by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) halt direct public funding to the global fossil fuel sector by the end of 2022; and (v) commit that all new vehicles sold in the country will be zero-emission on or before 2040. During the 2023 United Nations Climate Change Conference, which concluded on December 12, 2023, Canada signed an agreement with nearly 200 other parties, which includes renewed commitments to transitioning away from fossil fuels and further cutting GHG emissions.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the *Output-Based Pricing System Regulations*) and a fuel charge (enabled by the *Fuel Charge Regulations*), both of which impose a price on CO2e emissions. The GGPPA system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country.

Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO_2e in 2022. However, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. As of 2023, the benchmark price per tonne of CO_2e will increase by $15 per year until it reaches $170/tonne of CO_2e in 2030. Effective April 1, 2025, the minimum price permissible under the GGPPA rose to $95/tonne of CO_2e. While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, and came into force on January 1, 2020. By introducing new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. In December 2023, the federal government stated that the existing measures, which were designed to reduce the oil and gas sector's methane emissions by 40–45% by 2025 (relative to 2012) would not be sufficient to meet Canada's commitment to achieving a 75% reduction (below 2012 levels) by 2030. Accordingly, it released proposed amendments to the Federal Methane Regulations which would build on the existing requirements and increase stringency by introducing new prohibitions and limits on certain intentional emissions, a new risk-based approach around unintentional emissions, and a new performance-based approach for compliance that relies on continuous emissions monitoring systems, among others. The proposed amendments are targeted to come into force in January 2027.

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

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

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

The *Government of Canada introduced its 2030 Emissions Reduction Plan* (the "**2030 ERP**") on March 29, 2022. In the 2030 ERP, the Government of Canada proposes a roadmap to reduce its GHG emissions to 40-45% below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the oil and gas sector, among other measures. Canada is projected to surpass its interim objective to reduce emissions by 20% below 2005 levels by 2026 and is on track to meet its 2030 target.

On June 8, 2022 the *Canadian Greenhouse Gas Offset Credit System Regulations* were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the OBPS or those seeking to meet voluntary targets.

On June 20, 2022, the federal *Clean Fuel Regulations* came into force and in July 2023 they took effect. The Clean Fuel Regulations aim to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives, imposing obligations on primary suppliers of transportation fuels in Canada, and requiring fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

In November 2024, the federal government published the proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations (the "**Proposed Regulations"**). The Proposed Regulations would cap emissions from a range of oil and gas related activities, create an emissions cap-and-trade system, and require facility operators to comply with various reporting and remittance obligations. The final version of the Proposed Regulations is expected to be published in mid-2025 and come into force by January 1, 2026.

The Government of Canada has developed a Carbon Management Strategy, whereby it aims to deploy various carbon management technologies, including carbon capture, to help achieve federal climate goals. Carbon capture is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. As part of the 2021 budget, the federal government committed to investing $319 million over seven years into research, development and demonstrations to advance the commercial viability of carbon capture technologies, as they will be critical to reaching net-zero by 2050.

In June 2024, the federal government enacted various new tax credits for sustainability-related projects, including the Carbon Capture, Utilization, and Storage ("**CCUS**") Investment Tax Credit ("**ITC**"). The CCUS ITC is a refundable tax credit that applies to certain expenses incurred for eligible CCUS projects. It was enacted on June 19, 2024 (but deemed to have come into effect on January 1, 2022). The credit is available from January 1, 2022, until December 31, 2040, with the magnitude of the credit being reduced by 50% beginning on January 1, 2031.

In June 2023, the International Sustainability Standards Board ("**ISSB**") issued two international environmental reporting standards: IFRS S1, which addresses sustainability-related disclosure, and IFRS S2, which addresses climate-related disclosure. The Canadian Sustainability Standards Board ("**CSSB**") subsequently released for public comment substantially similar proposed Canadian versions of the international standards ("**CSDS 1**" and "**CSDS 2**"), which were finalized December 2024 (collectively, the "**Canadian Standards**").

The Canadian Standards require issuers, among other things, to include quantitative data regarding their climate change considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 GHG emissions. The finalized Canadian Standards are substantially similar to IFRS S1 and S2 (and earlier drafts of CSDS 1 and CSDS 2), however they have extended implementation timelines for select criteria. Canadian companies are not required to follow the Canadian Standards at this time, however the Canadian Securities Administrators are considering amending Canadian reporting requirements to include certain aspects of these new Canadian Standards; to what extent they will be adopted remains unclear.

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

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 82 megatonnes of GHG in 2023, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 (as amended January 1, 2023) and replaced the previous Carbon Competitiveness Incentives Regulation. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The GGPPA system applies in part in Saskatchewan for specific industry sectors, and the federal backstop continues to apply to emissions sources not covered by the provincial emissions legislation. In Manitoba, the federal system applies in full, whereas it does not apply in British Columbia, which has its own system altogether.

The Government of Alberta committed to lowering annual methane emissions from 2014 levels by 45% by 2025 and reached this target 3 years early. The Government of Alberta enacted the Methane Emission Reduction Regulation on January 1, 2020, and in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta. Similarly, in 2024, the Government of Saskatchewan and Canada entered into a similar equivalency agreement such that the Federal Methane Regulations will not apply in Saskatchewan.

Indigenous Rights

Constitutionally mandated government-led consultation with, and if applicable, accommodation of the rights of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration 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 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 The United Nations Declaration on the Rights of Indigenous Peoples Act Action Plan (the "Action Plan") with respect to aligning federal laws with UNDRIP, which has a 2023-2028 implementation timeframe. In June 2024, the federal government tabled its Third Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"), which provides various progress updates, including on the implementation of Canada's Action Plan.

There are various pieces of Indigenous-related legislation currently being considered, and regulations being developed, by the federal government, including the proposed First Nations Clean Water Act (currently being considered by the House of Commons) and regulations regarding Indigenous impact assessment co-administration agreements (currently being developed under the Impact Assessment Act). In addition to the changing legislative landscape, common law precedent regarding existing and new Indigenous-related laws continues to develop. Such developments are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines.

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

On January 18, 2023, the Government of British Columbia and BRFN signed the Blueberry River First Nations Implementation Agreement (the "**BRFN Agreement**"). The BRFN Agreement aims to address cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200-million restoration fund by June 2025, an ecosystem-based management approach for future land-use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas activities. BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years. In July 2024, BRFN filed a civil claim against the Province of British Columbia with respect to the first implementation plan made under the BRFN Agreement, which raises questions about implementation challenges of such an agreement.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations — Fort Nelson, Saulteau, Halfway River and Doig River First Nations — reached consensus on a collaborative approach to land and resource planning (the "**Consensus Agreement**"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue sharing approach to support the priorities of Treaty 8 First Nations communities.

In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. Beaver Lake Cree Nation ("**BLCN**") brought a similar Treaty claim against the Government of Alberta in 2008, and after 10 years and millions of dollars spent attempting to advance the claim, BLCN filed an application for advanced cost which, if successful, would require both the Alberta and federal governments to pay part of BLCN's litigation costs. This claim ultimately made its way to the SCC, which ruled in favour of BLCN, establishing a new test regarding whether an applicant "can afford" litigation. The initial Treaty claim has been remitted back to the trial court and the parties have been ordered to pay annual litigation costs (including the Government of Alberta being ordered to pay $1.5 million annually) until the matter is settled. The long-term impacts of these lawsuits on the Canadian oil and gas industry remain uncertain.

RISK FACTORS

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

Exploration, Development and Production Risks

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

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

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

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

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 our business, financial condition, results of operations and prospects.

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

Prices, Markets and Marketing

Our ability to market our oil and natural gas may depend upon our ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contracts for the delivery of oil and NGLs by rail. Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by us, including:

- deliverability uncertainties related to the distance our reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and

- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas.

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 OPEC+, political uncertainties including the threat of imposed tariffs on oil and natural gas imports into the United States, sanctions imposed on certain oil producing nations by other countries, the Russian Ukrainian war and conflicts in the Middle East, or other adverse economic or political developments in the United States, 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 of oil and natural gas are also subject to the availability of foreign markets our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of our reserves. We might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flow from operating activities and may have a material adverse effect on our business, financial condition, results of operations and prospects.

See "*Industry Conditions – Transportation Constraints and Market Access*".

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Trade War

Since the inauguration of Donald Trump as president of the United States, the United States has made a number of announcements relating to imposing tariffs on (among others) exports from Canada to the United States. In response, the Canadian federal and provincial governments have announced a number of retaliatory actions including potential tariffs on certain goods exported from the United States to Canada. The U.S. has also announced tariffs on goods imported from, among others, Mexico and China. The United States government has also made several announcements pausing the imposition of tariffs. At the present time, it is unclear whether tariffs will be imposed or not and on what goods such tariffs will apply to. If imposed, it is unclear whether such tariffs will be permanent or temporary. If imposed, these tariffs, and any changes to these tariffs or imposition of any new tariffs, taxes or import or export restrictions or prohibitions, could have a material adverse effect on the Canadian economy, the Canadian oil and natural gas industry and our business. Furthermore, there is a risk that the tariffs imposed by the U.S. on other countries will trigger a broader global trade war which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and our business.

Market Price of our Common Shares

Market price fluctuations in the Common Shares may be due to actual or anticipated fluctuations in our financial condition, results of operations and prospects, our operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by us or our competitors, along with a variety of additional factors, including, without limitation, those set forth under the heading "*Forward-Looking Information and Statements*". Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

In addition, the trading price of the 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 our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the oil and natural gas market and worldwide pandemics. In recent years, the volatility of commodity 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 our Common Shares has been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. These broad market fluctuations may adversely affect the market prices of the Debentures, Warrants and the Common Shares.

Inflation, Interest Rates and Cost Management

Our operating costs could escalate and become uncompetitive due to high levels of inflation, supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, power costs, commodity prices, and additional government intervention through stimulus spending or additional regulations experienced in Canada, the United States and other countries. These factors have increased our operating costs. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and cash flow from operating activities.

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

In addition, many central banks including the Bank of Canada and U.S. Federal Reserve have taken steps to raise interest rates in an attempt to combat inflation. The rise in interest rates has impacted our borrowing costs. The increase in borrowing costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and cash flow from operating activities. Rising interest rates could also result in a recession in Canada, the United States or other countries. A recession may have a negative impact on demand for oil and natural gas, causing a decrease in commodity prices. A decrease in commodity prices would immediately impact our revenues and cash flow from operating activities and could also reduce drilling activity on our properties. It is unknown how long inflation will continue to impact the economies of Canada and the United States and how inflation and rising interest rates will impact oil and gas demand and commodity prices.

Gathering and Processing Facilities, Pipeline Systems, Trucking and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by truck and rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems, trucking routes and railway lines. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do 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 our ability to process our production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Availability of Supplies for EOR Schemes

We are reliant on the availability of water and CO_2 supplies for our EOR schemes. Should there be a disruption in the delivery or cessation of these supplies this could have a negative impact on the production of oil and natural gas and the associated reserves of these properties. Waterflood EOR schemes are those which involve the injection of water into an oil reservoir to maintain reservoir pressure. In most cases, the water produced is re-injected plus additional water sourced from compatible water bearing reservoirs or fresh water sources. There is no certainty that we will have access to the required volumes of water or CO_2 in the future.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than we do. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, methods and reliability of delivery and storage.

Reliance on a Skilled Workforce and Key Personnel

Our operations and management 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 our business plans which could have a material adverse effect on our business, financial condition, results of operations and prospects.

Competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. We do not have any key personnel insurance in effect. Contributions of the existing management team to our immediate and near-term operations are likely to be of central importance. In addition, certain of our current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we 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 Cardinal.

Credit Facility Arrangements

The amount authorized under our Credit Facility is dependent on the borrowing base determined by our lenders. We are required to comply with certain non-financial covenants under the Credit Facility and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under our Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, from time to time, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our 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. See "*Description of our Capital Structure – Credit Facility*".

Our lenders use our reserves, commodity prices, applicable discount rate and other factors to periodically determine our borrowing base. Commodity prices have recently increased but remain volatile as a result of various factors including limited egress options for Western Canadian oil and natural gas producers, global geopolitical tensions, actions taken to limit OPEC and non-OPEC production and increasing production by U.S. shale producers. Any decrease in commodity prices could reduce our borrowing base, reducing the funds available to us under the Credit Facility. This could result in the requirement to repay a portion, or all, of our indebtedness.

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

Dividends

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that, among other things, no default, event of default or borrowing base shortfall exists, would reasonably be expected to result from, such declaration or payment.

The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, the amount of taxes payable by us, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Board of Directors and our management, our dividend policy could change from time to time and, as a result, future cash dividends could be reduced or suspended entirely. The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us 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 us 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, our ability 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 we are required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Geopolitical Risks

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

In particular, the Trump administration in the United States has stated it will be examining the U.S. trade system and potentially imposing new or increased tariffs or taxes on exports out of Canada into the United States, which could include increased tariffs on oil and natural gas. Any such potential tariffs or taxes could have a material adverse impact on the Canadian economy, the Canadian oil and natural gas industry and our business. Refer to "*Risk Factors – Trade War*".

Our business is global in scope and benefits from the free flow of goods and services between countries and is therefore affected by trade agreements and other government treaties, regulations and policies relating to international commerce. Any changes that increase the cost of or limit international trade or otherwise impact the global economy, including through the increase in prices for inputs and materials, could have a material adverse effect on our business, financial condition, and results of operations. In particular, the Trump administration in the United States has stated it will be examining the U.S. trade system and potentially imposing new tariffs on exports out of Canada into the United States, which could include tariffs on oil and natural gas. Any such potential tariffs or taxes could have a material adverse impact on the Canadian economy, the Canadian oil and natural gas industry and us.

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

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt our activities. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Transportation Constraints and Market Access*".

Development, Commissioning, and Operational Risks

The development, commissioning, and operation of the Reford Project is based on management's expectations, and may be delayed by several factors, some of which are beyond Cardinal's control. There is a risk that development, commissioning, and achievement of commercial production of heavy crude oil from the Reford Project will not be completed on time or on budget, or at all. Successful development and operation of the Reford Project may be affected by the design and construction of an efficient processing facility, the cost and availability of suitable machinery, supplies, equipment and skilled labor, the existence of competent operational management, prudent financial administration, and the availability and reliability of appropriately skilled and experienced employees. It is common for new facilities to experience unexpected problems and delays during construction, development, start-up, and commissioning activities due to late delivery of components, the inadequate availability of skilled labor and processing equipment, energy and chemical reagents at an economic cost, adverse weather or equipment failures, the rate at which expenditures are incurred, delays in construction schedules, or delays in obtaining the required permits or consents, or to obtain the required financing. Although we attempt to control and fix certain of the material expected costs associated with the Reford Project, the costs, timing, and complexities of developing and operating the Reford Project may be significantly higher than anticipated, which could add to the cost of development, production, and operation and/or impair production and activities, thereby affecting Cardinal's profitability.

Construction and Start-Up of the Reford Project

The success of construction projects and the start-up of the Reford Project, and other future SAGD projects, is subject to a number of risks and challenges including the availability and performance of engineering and construction contractors, suppliers and consultants; the implementation of new industrial processes; the receipt of required governmental approvals and permits in connection with the construction of the Reford Project, and other future SAGD projects, and the conduct of operations, including environmental and operating permits; price escalation on all components of construction and start-up and engineering adjustments. Any delay in the performance of any one or more of the contractors, suppliers, consultants or other persons on which we are dependent in connection with our construction and development activities, a delay in or failure to receive the required governmental approvals and permits in a timely manner or on reasonable terms, or a delay in or failure in connection with the completion and successful operation of the operational elements in connection with the Reford Project, and other future SAGD projects, could delay or prevent the construction and start-up as planned and may result in additional costs being incurred by us beyond those budgeted. There can be no assurance that current or future construction and start-up plans implemented by us will be successful.

SAGD Technology

Current technologies used for the recovery of heavy crude oil is energy intensive, including SAGD which requires significant consumption of natural gas in the production of steam used in the recovery process. The amount of steam required in the recovery process varies and therefore impacts costs. The performance of the reservoir affects the timing and levels of production using SAGD technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our business, financial condition, results of operations, and cash flows. There are risks associated with growth and other capital projects that rely largely or partly on new technologies, the incorporation of such technologies into new or existing operations, and acceptance of new technologies in the market. The success of projects incorporating new technologies cannot be assured.

Light Oil / Heavy Crude Oil Price Differentials

Processing heavy crude oil is more expensive than processing conventional light oil and it yields less high value products compared to refining light oil. Accordingly, producers of heavy crude oil receive lower prices for their oil. The difference between prices for heavy crude oil and light oil (such as WTI oil with an API gravity of 40°) is commonly referred to as the "light/heavy price differential". In order to calculate "light/heavy price differentials", the heavy crude oil prices are often derived from the Western Canadian Select ("**WCS**") at Hardisty, Alberta or Lloyd Blend at Hardisty, Alberta published prices. WCS is comprised of Canadian bitumen and heavy crude oils blended with sweet synthetic and condensate diluents and Lloyd Blend is a heavy, sour crude oil. Volatility in the light/heavy price differential is a result of availability of supply, seasonal demand, pipeline constraints and heavy crude oil conversion capacity of refineries. It is difficult to predict future price differentials and any increase in heavy crude oil differentials could have an adverse effect on Cardinal's business, financial condition, results of operations and cash flows, as it relates to its SAGD operations, including the Reford Project.

Changing Investor Sentiment

A number of factors, including the effects of the use of hydrocarbons on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments toward investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in 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 our Board of Directors, management and employees. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in us, or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares even if our operating results, underlying asset values or prospects have not changed.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider 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 our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our own. 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 we can focus our efforts and resources more efficiently. Depending on the market conditions for such non-core assets, certain of our non-core assets may realize less on disposition than their carrying value on our financial statements.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Our ability to execute projects and to market oil and natural gas depends upon numerous factors beyond our control, including:

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

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

Operational Dependence

In certain cases, other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our 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 we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, we 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, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on our financial and operational results. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*" and "*Risk Factors –* T*hird Party Credit Risk*".

Abandonment and Reclamation Costs

Cardinal needs to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of applicable approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial and, while we accrue a reserve in our financial statements for such costs in accordance with IFRS, such accruals may be insufficient.

It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, we may determine it prudent or be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If we establish a reclamation fund, our liquidity and cash flow may be adversely affected.

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines if a licensee or permit holder is unable to satisfy its regulatory obligations. The implementation of or changes to the requirements of liability management programs may result in significant increases to the security that must be posted by licensees, increased and more frequent financial disclosure obligations or may result in the denial of licence or permit transfers, which could impact the availability of capital to be spent by such licensees and could in turn materially adversely affect our business and financial condition. In addition, these liability management programs may prevent or interfere with a licensee's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must comply with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect us from commodity price declines, we 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, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

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

Diluent Supply

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent, or a restriction in access to diluent, may cause its price to increase, increasing the cost to transport heavy oil and bitumen to market. An increase to the cost of bringing heavy oil and bitumen to market may increase our overall operating cost and result in decreased net revenues, negatively impacting the overall profitability of our heavy oil and bitumen projects.

Regulatory Landscape

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry.

In order to conduct oil and natural gas operations, we require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the Competition Act and the Investment Canada Act could negatively affect our business, financial condition and the market value of our Common Shares or our assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*".

Royalty Regimes

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

Environmental Regulation

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

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are 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 our business, financial condition, results of operations and prospects.

Climate Change

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, at the 2021 United Nations Climate Change Conference, Canada's Prime Minister Justin Trudeau made several pledges regarding reducing Canada's GHG emissions and at the 2023 United Nations Climate Change Conference, Canada renewed its commitments to transition away from fossil fuels and further reducing GHG emissions. As discussed below, we face both transition risks and physical risks associated with climate change and climate change policy and regulations. See "*Industry Conditions – Climate Change Regulations*".

Transition Risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in our profitability and a reduction in the value of our assets.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including us, for alleged personal injury, property damage, or other potential liabilities. While we are not a party to any such litigation or proceedings, we 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 us, impact our operations and have an adverse impact on our financial condition.

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

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, in June 2023, the International Sustainability Standards Board has issued two new international sustainability disclosure standards with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators had previously published for comment Proposed National Instrument 51-107 – *Disclosure of Climate Related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada. It is expected that the introduction of the new international standards will instruct the manner in which new Canadian sustainability disclosure standards are finalized. If we are not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, our business and ability to attract and retain skilled employees, obtain regulatory permits, licenses, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Physical Risks

Based on our current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict our ability to access our 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. Certain of our assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to our assets or cause disruptions to the production and transport of our products or the delivery of goods and services in our supply chain.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of our 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 we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results.

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

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

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

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of funds from operations, borrowings, proceeds from asset sales and possible future equity sales, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our 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 our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or those affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including us, 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 us. We may be required to seek additional equity financing on terms that are highly dilutive to existing Shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and, from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, we may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

As a result of global economic and political conditions and the domestic lending landscape, we 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 us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our 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 our capital expenditure plans may result in a delay in development or production on our properties.

Issuance of Debt

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

Title to and Right to Produce from Assets

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

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

Reserves Estimates

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

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

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

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

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

Actual production and future net revenue derived from our 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 we intend to undertake in future years. The reserves and estimated future net revenue 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 our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blowouts, leaks of sour gas, property damage, personal injury or other hazards. Although we maintain 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, we 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 us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Our insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead us 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 which may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, our overall risk exposure could be increased and we could incur significant costs.

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 we will be able to respond to such competitive pressures and implement such technologies on a timely basis, or at an acceptable cost. If we do implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. If we are unable to utilize the most advanced commercially available technology, or are unsuccessful in implementing certain technologies, our business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of hydrocarbons and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and funds flow by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Dilution

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

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage and potentially expand our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

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

Litigation

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries (including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes). The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail 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 our financial condition.

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 we have interests may negatively impact our operations, development and exploratory activities in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact our progress and ability to explore and develop properties.

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

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

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have introduced or passed similar legislation and have begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government are uncertain; additional processes may be created or 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*".

Breach of Confidentiality

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

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

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

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 which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transport authorities may 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 our production if not otherwise tied-in. Certain of our oil and natural gas producing assets 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 we have 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 us.

Third Party Credit Risk

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

Conflicts of Interest

Certain of our directors or officers 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 *Business Corporations Act* (Alberta) 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 us 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 *Business Corporations Act* (Alberta). See "*Directors and Officers – Conflicts of Interest*".

Information Technology Systems and Cyber-Security

We have 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. We depend on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer contracts with operators and lessees and communicate with employees and third party partners.

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

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into our systems and obtain confidential information. Although we have a social media policy, we do not restrict the social media access of our employees. Despite these efforts, there are significant risks that we may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

We maintain policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. We also employ encryption protection of our confidential information, all computers and other electronic devices. Despite our efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage our information technology infrastructure. We apply technical and process controls in line with industry-accepted standards to protect our 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 our reputation, and any damages sustained may not be adequately covered by our current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

The protection of customer, employee, and company data is critical to our business. The regulatory environment in Canada surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. Certain legislation, including the *Personal Information Protection and Electronic Documents Act* in Canada, require 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 our 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 us to take additional measures to enhance security and/or assume higher liability under its contracts. As a result of legislative initiatives and customer demands, we 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.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and natural gas production, exploration and development in the Western Canada Sedimentary Basin. In the future, we may acquire or move into new industry related activities or new geographical areas and may acquire different energy-related assets; as a result, we may face unexpected risks or, alternatively, our exposure to one or more existing risk factors may be significantly increased, which may in turn result in our future operational and financial conditions being adversely affected.

Drought and Flooding

Water is an essential component of our drilling processes and our EOR and SAGD operations. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions such as those recently experienced in certain areas of Alberta, British Columbia and Saskatchewan 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. For the first time since 2001, Alberta's Drought Command Team has been authorized to negotiate water-sharing agreements with the water license holding, including in the Red Deer River, Bow River and Old Man River basins, to manage water use and mitigate the risks of drought. The AER further issued Bulletin 2023-43 on December 12, 2023 warning extremely low water levels in parts of Alberta in the fourth quarter of 2023 and a strong likelihood of low flows and low water levels persisting into 2024. If Cardinal is unable to obtain water to use in its 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 ultimately would have a detrimental effect on our financial condition, results of operations, and cash flows from operating activities.

Disposal of Fluids Used in Operations

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

Non-Governmental Organizations

The oil and natural gas exploration, development and operating activities conducted by us may, at times, be subject to public opposition. Such public opposition could expose us to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial 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 we will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require us to incur significant and unanticipated capital and operating expenditures.

Reputational Risk Associated with our Operations

Our business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards us or as a result of any negative sentiment toward, or in respect of, our 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 we operate as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. Our 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 we have 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 operations. In addition, if we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultants to operate our business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate-related litigation against governments and hydrocarbon companies may impact our reputation. See "*Risk Factors – Climate Change*".

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

Intellectual Property Litigation

Due to the rapid development of oil and natural gas technology, in the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that we have infringed the intellectual property rights of others or which we initiate against others we believe are infringing upon our intellectual property rights. Our involvement in intellectual property litigation could result in significant expense, adversely affecting the development of our assets or intellectual property or diverting the efforts of our technical and management personnel, whether or not such litigation is resolved in our favour. In the event of an adverse outcome as a defendant in any such litigation, we may, among other things, be required to:

- pay substantial damages and/or cease the development, use, sale or importation of processes that infringe upon other patented intellectual property;
- expend significant resources to develop or acquire non-infringing intellectual property;
- discontinue processes incorporating infringing technology; or
- obtain licences to the infringing intellectual property.

However, we may not be successful in such development or acquisition, or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on our business and financial results.

Carbon Capture, Utilization and Storage

We are subject to various market-specific risks related to the CCUS industry, as further outlined below, and should these risks materialize they may have a material adverse effect on us.

The CCUS industry risks materializing in respect of a slow ramp-up of CCUS in the global market, reduced or delayed CO_2 tax and incentive increases, and/or supply chain uncertainty and challenges in new market conditions may have a negative impact on our operations and development.

Evolving climate targets and stronger investment incentives are expected to add momentum to the CCUS industry; however, should such favorable regulatory policies and financial support no longer be available or be reduced, such change(s) may have an adverse effect on development of the industry in which we operate, which in turn may have an adverse effect on our ability to expand our operations and ultimately on our financial position and results. The speed of the transition into a low-carbon economy will also affect the realization of CCUS projects and governmental support and environmental regulation are key factors that will influence the speed of this transition.

Tax credits or other government policies related to the development and adoption of CCUS may not be implemented in the manner that we expect, or at all. Even if tax credits or government policies are implemented, we may fail to implement its CCUS program in a manner that allows it to take advantage of these credits.

In June 2024, the federal government enacted various new tax credits for sustainability-related projects, including the CCUS Investment Tax Credit (ITC). The CCUS ITC is a refundable tax credit that applies to certain expenses incurred for eligible CCUS projects. It was enacted on June 19, 2024, and deemed to have come into effect on January 1, 2022.

We intend to take advantage of the new and future government CCUS programs and, however we may fail to implement its CCUS program in a manner that allows us to take advantage of all or any available credits. Our future CCUS technology may prove not to be commercially viable, efficient, or operationally effective and efforts to respond to technological innovations may require significant financial investments and resources. Additionally, CCUS projects are dependent on prevailing carbon prices. A reduction in prevailing carbon prices could lead to CCUS projects not being economical. Failure by us to respond to changes in technology and innovations may render our future CCUS operations non-competitive and may have a material, negative effect on our results of operations, financial condition and future prospects.

Forced or Child Labour in Supply Chains

In May 2023 the Fighting Against Forced Labour and Child Labour in Supply Chains Act was passed and came into force on January 1, 2024. Pursuant to the new legislation, any company that is subject to the reporting requirements, including us, is required to file an annual report with respect to its supply chains. Due to the fact that the reporting requirements are new and the industry standard is still being determined, we will be at risk of inadvertently preparing a report that is insufficient. Further, in late 2024 the federal government signalled its intention to create a new and more onerous supply chain due diligence regime overseen by a new oversight agency, whereby reporting entities will be required to scrutinize their international supply chains for human rights risks and take action to resolve any such risks. While we are currently unaware of any forced or child labour in any of our supply chains, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which we have a connection, which could negatively impact our reputation.

Impact of Pandemics

In the event of a global pandemic, countries around the world may close international borders and order the closure of institutions and businesses deemed non-essential. This could result in a significant reduction in economic activity in Canada and internationally along with a drop in demand for oil and natural gas. Any reduction in economic activity in certain countries resulting from outbreaks, government-imposed lockdowns and other restrictions could have a negative effect on demand for oil and natural gas and could also aggravate the other risk factors identified herein.

Forward-Looking Statements

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

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

Specific Risks Related to the Debentures and the Warrants

No Prior Public Market for the Debentures or the Warrants

We will be required to obtain Toronto Stock Exchange approval prior to issuing any Common Shares on the Maturity Date or on the redemption of, or payment of interest on, the Debentures, as applicable. No assurance can be given that an active or liquid trading market for the Debentures or Warrants will develop or be sustained. If an active or liquid market for the Debentures or Warrants fails to develop or be sustained, the price at which the Debentures or Warrants trade may be adversely affected.

The market price of the Debentures or Warrants may be volatile and subject to wide fluctuations and will be based on a number of factors, including: (i) in the case of the Debentures, the prevailing interest rates being paid by companies similar to us; (ii) the overall condition of the financial and credit markets; (iii) in the case of the Debentures, interest rate volatility; (iv) the markets for similar securities; (v) actual or anticipated fluctuations in our financial condition, results of operations and prospects; (vi) the publication of earnings estimates or other research reports and speculation in the press or investment community; (vii) the market price and volatility of the Common Shares; (viii) changes in the industry in which we operate and competition affecting us; and (ix) general market and economic conditions in North America.

The condition of the financial and credit markets and prevailing interest rates have fluctuated in the past and are likely to fluctuate in the future. Fluctuations in these factors could have an adverse effect on the market price of the Debentures and Warrants.

Prior Ranking Indebtedness

The Debentures are subordinate to all of our existing and future Senior Secured Indebtedness. The Debentures are also effectively subordinate to our other secured indebtedness that is not Senior Secured Indebtedness to the extent of the value of the assets securing such secured indebtedness. Therefore, if we become bankrupt, liquidate our assets, reorganize or enter into certain other transactions, our assets will be available to pay our obligations with respect to the Debentures only after we have paid all of our Senior Secured Indebtedness and other secured indebtedness in full. There may be insufficient assets remaining following such payments to pay amounts due on any or all of the Debentures then outstanding.

The Debentures are not guaranteed by our subsidiaries and are therefore effectively structurally subordinated to all of the debt of these subsidiaries and claims of creditors of such subsidiaries except to the extent we are a creditor of such subsidiaries ranking at least *pari passu* with such other creditors. Accordingly, in the event of insolvency, liquidation, reorganization, dissolution or other winding-up of any such subsidiary, all of that subsidiary's creditors (including trade creditors) would be entitled to payment in full out of that subsidiary's assets before the Corporation would be entitled to any payment. There may be insufficient assets remaining following such payments to pay amounts due on any or all of the Debentures then outstanding.

Absence of Covenant Protection

The Debenture Indenture does not limit our ability to incur additional indebtedness for borrowed money or other obligations, including Senior Secured Indebtedness or other secured indebtedness (which would rank senior to the Debentures to the extent of the collateral securing such indebtedness), unsecured and unsubordinated indebtedness (which would rank *pari passu* with the Debentures), and liabilities or obligations that do not constitute indebtedness. Further, the Debenture Indenture does not limit our ability to mortgage, pledge or charge our properties to secure any indebtedness or liabilities. Nor will the Debenture Indenture prohibit or limit our ability to pay distributions, except where an Event of Default has occurred and such default has not been cured or waived, which, if paid, will reduce our available cash flow and assets available to holders of the Debentures upon redemption or maturity of the Debentures. The Debenture Indenture does not contain any provision specifically intended to protect holders of the Debentures in the event of a future leveraged transaction involving us. If new debt is added to our current debt levels, the related risks that we now face could intensify.

If we incur additional indebtedness for borrowed money or other obligations or liabilities, it may have the effect of reducing the amount of proceeds distributed to holders of Debentures in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of or such proceedings involving us. If we incur any additional obligations that rank equally with the Debentures, subject to collateral arrangements, the holders of such obligations will be entitled to share ratably with holders of the Debentures in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us.

Prevailing Yields on Similar Securities

Prevailing yields on similar securities will affect the market value of the Debentures. Assuming all other factors remain unchanged, the market value of the Debentures will decline as prevailing yields for similar securities rise and will increase as prevailing yields for similar securities decline.

Possible Dilutive Effects on Holders of Common Shares

We may determine to redeem outstanding Debentures for Common Shares or repay outstanding principal amounts of the Debentures at maturity by issuing additional Common Shares. Accordingly, holders of Common Shares may suffer dilution. There is no guarantee that we will be able to repay the outstanding principal amount in cash upon maturity of the Debentures.

Credit Risk and Earnings Coverage Ratios

Our ability to make scheduled payments on or to refinance its debt obligations, including the Debentures, depends on our financial condition and operating performance, which are subject to a number of factors beyond our control.

We may be unable to maintain a level of cash flow from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on its indebtedness, including the Debentures. The Credit Facility may restrict payment or repayment, as applicable, of amounts under, pursuant or relating to the Debentures, including without limitation, payments of the principal sum of the Debentures and payments of any interest payments thereon during the continuance of a default, event of default or borrowing base shortfall under or pursuant to the Credit Facility.

If our cash flow and capital resources are insufficient to fund our debt service obligations, we could face substantial liquidity problems and could be forced to reduce or delay investments and capital expenditures or to dispose of material assets or operations, seek additional debt or equity capital or restructure or refinance our indebtedness, including the Debentures. We may not be able to effect any such alternative measures on commercially reasonable terms or at all and, even if successful, those alternative actions may not allow us to meet our scheduled debt service obligations.

Our inability to generate sufficient cash flow to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, would materially and adversely affect our business, results of operations, financial condition and our ability to satisfy our obligations under the Debentures.

The Debentures are not rated by any designated rating organization and we have no current plans to apply for a credit rating.

See also "*Risk Factors – Issuance of Debt*" and "*Risk Factors – Additional Funding Requirements*".

No Assurance Future Financing Will be Available

We may need to refinance certain of our existing debt instruments at or prior to their maturity or obtain additional financing in the future. The ability to obtain such additional financing will depend upon a number of factors, including prevailing market conditions and our operating performance. There can be no assurance that any such financing will be available to us on favorable terms or at all. If financing is available through the sale of debt, equity or capital properties, the terms of such financing may not be favorable to us. Failure to raise capital when required could have a material adverse effect on our business, financial condition and results of operations.

See also "*Risk Factors – Issuance of Debt*" and "*Risk Factors – Additional Funding Requirements*".

Redemption Prior to Maturity

The Debentures may be redeemed at certain times prior to maturity, at our option, in whole or in part, subject to certain conditions (including the terms and conditions of the Credit Facility). Holders of Debentures should understand that this redemption option may be exercised if we are able to refinance at a lower interest rate or it is otherwise in our interests to redeem the Debentures. See "*Description of Our Capital Structure – Debentures – Redemption*" and "*Risk Factors – Specific Risks Related to the Debentures and the Warrants – Change of Control*" below.

Change of Control

We will be required to make an offer to purchase all of the outstanding Debentures for cash in the event of certain transactions that would constitute a Change of Control. We cannot assure holders of Debentures that, if required, we would have sufficient cash or other financial resources at that time or would be able to arrange financing to pay the purchase price of the Debentures in cash. Our ability to purchase the Debentures in such an event may be limited by law, by the Debenture Indenture governing the Debentures, by the terms of other present or future agreements relating to our and our subsidiaries credit facilities and other indebtedness and agreements that we or our subsidiaries may enter into in the future which may replace, supplement or amend our or our subsidiaries future debt. Our or our subsidiaries future credit agreements or other agreements may contain provisions that could prohibit the purchase by us of the Debentures without the consent of the lenders or other parties thereunder. If our obligation to offer to purchase the Debentures arises at a time when we are prohibited from purchasing or redeeming the Debentures, we could seek the consent of lenders to purchase the Debentures or could attempt to refinance the borrowings that contain this prohibition. If we do not obtain a consent or refinance these borrowings, we could remain prohibited from purchasing the Debentures. Our failure to purchase the Debentures would constitute an Event of Default under the Debenture Indenture, which might constitute a default under the terms of our other indebtedness at that time.

In the event that Debentureholders holding 90% or more of the Debentures of a particular series have tendered their Debentures for purchase pursuant to the Debenture Offer, we may redeem the remaining Debentures of that series on the same terms. See "*Description of Our Capital Structure – Debentures – Change of Control*".

In addition, in the event of a Change of Control prior to March 31, 2028, we may redeem the Initial Debentures, at our option and for cash only, at a cash redemption price equal to 103.875% of the principal amount of the Initial Debentures plus an aggregate amount equal to the interest that (i) has accrued and is unpaid to such date of redemption; and (ii) would have accrued and been payable up to and including March 31, 2028 had the Initial Debentures not been redeemed. We may also redeem the Second Series Debentures in the event of a Change of Control, at our option and for cash only, prior to September 30, 2028, at a cash redemption price equal to 104.125% of the principal amount of the Second Series Debentures plus an aggregate amount equal to the interest that (i) has accrued and is unpaid to such date of redemption; and (ii) would have accrued and been payable up to and including September 30, 2028 had the Second Series Debentures not been redeemed.

The Debenture Trustee Will Take Instructions From a Majority of Holders Whose Interests May Not Align With Other Holders

Except in certain limited circumstances, the Debentures were issued and deposited in electronic form with CDS Clearing and Depository Services Inc. ("**CDS**") or its nominee pursuant to the book-based system administered by CDS. Beneficial holders of the Debentures will have their rights and interests in the Debentures governed by the terms of the Debenture Indenture and will be represented by the Debenture Trustee appointed thereunder. The Debenture Trustee will take direction from holders of the Debentures in accordance with the terms of the Debenture Indenture, which may require a minimum number of holders of the Debentures to vote on a course of action prior to the implementation thereof. As a result, the Debenture Trustee may take direction from one or more institutional holders of the Debentures to the extent that such holders of the Debentures maintain a significant interest in the Debentures. Such holders of the Debentures may not have the same interests in outcomes as other holders of Debentures.

Alternatively, if the beneficial interest in the Debentures is widely held, the Debenture Trustee may not receive instructions in a timely manner or may not receive instructions at all. In the event the Debenture Trustee is unable to obtain timely instructions from holders of the Debentures, holders of the Debentures may not achieve the outcomes they might have otherwise been able to if the Debenture Trustee had received instructions in a timely manner.

Canadian Bankruptcy and Insolvency Laws May Impair the Debenture Trustee's Ability to Enforce Remedies Under the Debentures

The rights of the Debenture Trustee to enforce remedies could be delayed by the restructuring provisions of applicable Canadian federal bankruptcy, insolvency and other restructuring legislation if the benefit of such legislation is sought with respect to us. For example, both the *Bankruptcy* and *Insolvency Act* (Canada) and the *Companies' Creditors Arrangement Act* (Canada) contain provisions enabling an insolvent person to obtain a stay of proceedings against its creditors and to file a proposal to be voted on by the various classes of its affected creditors. A restructuring proposal, if accepted by the requisite majorities of each affected class of creditors, and if approved by the relevant Canadian court, would be binding on all creditors within each affected class, including those creditors that did not vote to accept the proposal. Moreover, this legislation, in certain instances, permits the insolvent debtor to retain possession and administration of its property, subject to court oversight, even though it may be in default under the applicable debt instrument, during the period that the stay against proceedings remains in place. The powers of the court under the *Bankruptcy and Insolvency Act* (Canada), and particularly under the *Companies' Creditors Arrangement Act* (Canada), have been interpreted and exercised broadly so as to protect a restructuring entity from actions taken by creditors and other parties. Accordingly, Cardinal cannot predict whether payments under the Debentures would be made during any proceedings in bankruptcy, insolvency or other restructuring, whether or when the Debenture Trustee could exercise its rights under the Debenture Indenture or whether and to what extent holders of the Debentures would be compensated for any delays in payment, if any, of principal, interest and costs, including the fees and disbursements of the respective trustees.

Holders of Debentures Will Only Have the Rights of an Equity Holder in the Event We Redeem the Debentures or Satisfy the Principal on Maturity by Issuing Common Shares

We have the right, at our sole discretion, to redeem or repay outstanding principal amounts thereunder at redemption or maturity of the Debentures by issuing Common Shares rather than the payment of cash. If such option is exercised by us, holders of Debentures will become holders of our equity securities and will, consequently, be subject to the general risks and uncertainties affecting shareholders, including the ability to claim an entitlement only in its capacity as a Shareholder.

The price paid for each Debenture may bear no relationship to the price at which the equity issuable on redemption or maturity of the Debentures may trade. We cannot predict at what price the Common Shares may trade and there can be no assurance that an active trading market for the Common Shares will be sustained or what prices may be realized upon the sale of Common Shares.

Volatility of Market Price of Common Shares

The market price of the Common Shares may be volatile. The volatility may affect the ability of holders of Debentures to sell the Debentures at an advantageous price and may result in greater volatility in the market price of the Debentures than would otherwise be expected for debt securities that cannot be repaid with equity. See "*Risk Factors – Market Price of our Common Shares*".

These broad market fluctuations may adversely affect the market prices of the Debentures and the Common Shares.

Change in Tax Laws

The Debenture Indenture does not contain a requirement that we increase the amount of interest or other payments to holders of Debentures in the event that we are required to withhold amounts in respect of income or similar taxes on payment of interest or other amounts on the Debentures. At present, we will not withhold from such payments to holders of Debentures resident in Canada or in the United States who deal at arm's length with us, but no assurance can be given that applicable income tax laws or treaties will not be changed in a manner that may require us to withhold amounts in respect of tax payable on such amounts.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings we are or were a party to, or that any of our property is or was the subject of, during our most recent financial year, nor are any such legal proceedings known to us to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of our current assets.

There are no: (a) penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority since our inception; (b) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; and (c) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority since our inception.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described herein, there is no material interest, direct or indirect, of any: (a) director or executive officer; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of our voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction during the previous three years that has materially affected or is reasonably expected to materially affect us

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are KPMG LLP, Chartered Professional Accountants, Suite 3100, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9. KPMG LLP has been our auditors since inception.

The transfer agent and registrar for the Common Shares is Odyssey Trust Company at its principal offices in Calgary, Alberta, Vancouver, British Columbia and Toronto, Ontario.

The trustee, transfer agent and registrar for the Debentures is Odyssey Trust Company at its principal transfer office in Calgary, Alberta. The warrant agent for the Warrants is Odyssey Trust Company at its principal transfer offices in Calgary, Alberta.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts that we have entered into prior to the date of this Annual Information Form, which can reasonably be regarded as presently material, are the following:

1. the fifth amended and restated credit agreement dated December 12, 2024 as amended by the first amending agreement made effective as of February 27, 2025;

2. the Warrant Indenture;

3. the Debenture Indenture; and

4. the Bonus Award incentive Plan.

Copies of these contracts may be viewed on SEDAR+ at *www.sedarplus.ca*.

EXPERTS

Interests of Experts

GLJ prepared the GLJ Report and the Consolidated Reserve Report and McDaniel prepared the McDaniel Report. None of the designated professionals of GLJ or McDaniel have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statements, reports or valuations prepared by it, at any time thereafter or to be received by them.

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

In addition, none of the aforementioned persons or companies, nor any 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 us or of any of our associates or affiliates, except for John A. Brussa, one of our directors, is the Chair and a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR+ profile at *www.sedarplus.ca* and on our website at *www.cardinalenergy.ca*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our proxy materials relating to our annual and special shareholders meeting to be held on May 9, 2025. Additional financial information is contained in our financial statements for the year ended December 31, 2024, and the related management's discussion and analysis.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Cardinal Energy Ltd.
600, 400 – 3rd Avenue S.W.
Calgary AB T2P 4H2
Tel: (403) 234-8681
Fax: (403) 234-0603

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

FORM 51-101F3

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

An independent qualified reserves evaluator has evaluated Cardinal's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Cardinal has:

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

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

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

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

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources 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) "*M. Scott Ratushny*"
M. Scott Ratushny
Chair and Chief Executive Officer

(signed) "*John Festival*"
John Festival
Director and Chair of the Reserves Committee

(signed) "*Shawn Van Spankeren*"
Shawn Van Spankeren
Chief Financial Officer

(signed) "*John Gordon*"
John Gordon
Director and Chair of the Audit Committee

March 26, 2025

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

FORM 51-101F2

To the board of directors of Cardinal Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2024, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate –M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	December 31, 2024	Canada	-	1,940,539	-	**1,940,539**
McDaniel & Associates Consultants Ltd.	December 31, 2024	Canada	-	418,894	-	**418,814**
Total				2,359,433		**2,359,433**

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

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

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

Executed as to our report referred to above:

GLJ Ltd., Calgary Alberta, Canada, February 21, 2025.

"Originally Signed By"
Scott M. Quinell, P.Eng.
Vice President, Corporate Evaluations

McDaniel & Associates Consultants Ltd, Calgary Alberta, Canada, February 21, 2025.

"Originally Signed By"
Michael Verney, P.Eng.
Executive Vice President

APPENDIX C

AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

Establishment of Committee

The board of directors (the "**Board**") of Cardinal Energy Ltd. ("**Cardinal**" or the "**Corporation**") hereby establishes a committee of the Board to be called the Audit Committee (the "**Committee**").

Role and Objectives

1. The purpose of the Committee is to assist the Board in fulfilling its responsibility for:

   (a) oversight of the nature and scope of the annual audit;

   (b) oversight of the Corporation's management ("**Management**") reporting on internal financial and accounting standards and practices;

   (c) review of the adequacy of Cardinal's financial information, accounting systems and procedures;

   (d) review of Cardinal's financial reporting and statements;

   and the Board has charged the Committee with the responsibility of recommending, for Board approval, Cardinal's interim and annual audited financial statements and related management's discussion and analysis ("**MD&A**") and, if delegated by the Board, other mandatory disclosure releases containing financial information of the Corporation.

2. The primary objectives of the Committee are as follows, to:

   (a) assist the directors of the Corporation ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Cardinal and related matters;

   (b) enhance communication between the Directors and external auditor;

   (c) enhance the external auditor's independence;

   (d) strengthen the credibility and objectivity of Cardinal's financial reports; and

   (e) facilitate in-depth discussions between Directors on the Committee, Management and the external auditor.

3. The function of the Committee is one of oversight of Management and the external auditor in the execution of their responsibilities. Management is responsible for the preparation, presentation and integrity of the financial statements of the Corporation, maintaining appropriate accounting and financial reporting principles and policies and implementing appropriate internal controls and procedures. The external auditor is responsible for planning and carrying out a proper audit of the annual financial statements of the

Corporation and reviewing the interim financial statements of the Corporation prior to their filing with securities regulatory authorities and other procedures.

Membership of Committee

1. The Committee shall be comprised of at least three (3) Directors, all of whom shall be "independent" (as such term is used in National Instrument 52-110 – *Audit Committees* or its successor instrument (as amended from time to time)) ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

3. The Board shall have the power to appoint the Chair of the Committee (the "**Committee Chair**") and the other members of the Committee.

Specific Duties and Responsibilities

1. It is the responsibility of the Committee to:

    (a) oversee the work of the external auditor, including resolution of any disagreements between Management and the external auditor regarding financial reporting;

    (b) monitor, on behalf of the Board, the integrity of Cardinal's internal control and management information systems, including:

        (i) material business risks; and

        (ii) compliance with legal, ethical and regulatory requirements including the certification process;

    (c) annually review Cardinal's process for testing its internal controls; and

    (d) review with the external auditor (and internal auditor if one is appointed by Cardinal), on an annual basis, their assessment of the internal controls of Cardinal, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses.

2. It is the responsibility of the Committee to review the annual and interim financial statements of Cardinal and related MD&A prior to their submission to the Board for approval and before Cardinal publicly discloses this information. The process should include but not be limited to:

    (a) reviewing the appropriateness of significant accounting principles and any changes in accounting principles, or in their application, which may have a material impact on the current or future years' interim unaudited and annual audited financial statements;

    (b) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

    (c) reviewing significant accruals, reserves or other estimates such as impairment and asset retirement obligations;

(d) reviewing the accounting treatment of unusual or non-recurring transactions;

(e) reviewing compliance with covenants under loan agreements;

(f) reviewing disclosure requirements for commitments and contingencies;

(g) reviewing adjustments raised by the external auditor whether or not included in the financial statements;

(h) reviewing unresolved differences or disagreements between Management and the external auditor, if any;

(i) reviewing Cardinal's risk management policies and procedures including hedging policies, litigation matters, and insurance programs;

(j) reviewing related party transactions and taking reasonable steps to ensure that the nature and extent of such transactions are properly disclosed;

(k) reviewing significant or unusual transactions outside the normal course of business of Cardinal;

(l) reviewing explanations of significant variances with comparative reporting periods; and

(m) reviewing and approving Cardinal's hiring policies regarding partners, employees and former partners and employees of the present and former external auditor of the Corporation.

3. The Committee shall periodically assess and be satisfied with the adequacy of the Corporation's procedures for the review of Cardinal's public disclosure of financial information extracted or derived from Cardinal's financial statements, including earnings press releases, prospectuses, annual information forms and business acquisition reports, other than the annual and interim required filings, prior to their release.

4. With respect to the appointment of external auditor by the Board, the Committee shall:

(a) recommend to the Board the external auditor to be nominated;

(b) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditor and a confirmation that the external auditor will report directly to the Committee;

(c) review and discuss with the external auditor, on an annual basis, all significant relationships such auditor has with Cardinal to determine the auditor's independence;

(d) when there is to be a change in auditor, review the issues related to the change and the information to be included in the required notice to securities regulators of such change, if required; and

(e) review and pre-approve any non-audit services to be provided to Cardinal or its subsidiaries (if any) by the external auditor and consider the impact on the independence of the auditor. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

5. The Committee shall:

    (a) review with the external auditor their plan for their audit and, upon completion of the audit, their reports on the financial statements of Cardinal and its subsidiaries (if any);

    (d) review with Management, Cardinal's, financial risk assessment and management policies and procedures (i.e. hedging, litigation, insurance and tax audits); and

    (e) receive updates from Management with respect to information technology matters, including with respect to the Corporation's cyber security programs to address potential cyber-security risks.

6. The Committee shall establish procedures for:

    (a) the receipt, retention and treatment of complaints received by Cardinal regarding accounting, internal accounting controls or auditing matters; and

    (b) the confidential, anonymous submission by employees of Cardinal of concerns regarding questionable accounting or auditing matters.

7. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements).

8. The Committee shall meet periodically with the external auditor, independent of Management. The issues for consideration should include, but are not limited to:

    (a) obtaining feedback on competencies, skill sets and performance of key members of the financial reporting team;

    (b) enquiring as to significant differences from prior year period audits or reviews;

    (c) enquiring as to transactions accounted for in an acceptable manner but not a basis which, in the opinion of the external auditor was not the preferable accounting treatment;

    (d) enquiring as to any differences between Management and the external auditor;

    (e) enquiring as to material differences in accounting policies, disclosures or presentation from prior periods;

    (f) enquiring as to deficiencies in internal controls identified in the course of the performance of the procedures by the external auditor; and

    (g) enquiring as to any other matters or observations that the external auditor would like to bring to the attention of the Committee.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the chair of the meeting shall not be entitled to a second or casting 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 shall 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 shall be taken. The Chief Financial Officer and Chief Executive Officer of Cardinal shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Committee Chair.

4. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.

5. The Committee may invite such officers, Directors and employees of Cardinal and its subsidiaries (if any) as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

6. The Committee may retain and pay persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at such compensation as established by the Committee and at the expense of Cardinal without any further approval of the Board.

7. The Committee shall have the authority to investigate any financial related activity of the Corporation and to communicate directly with the external auditor. All employees of the Corporation are to cooperate as requested by the Committee.

8. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all their powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

9. Any issues arising from these meetings that relate to the relationship between the Board and Management should be communicated by the Committee Chair to the Chair of the Board or the independent lead Director.

Last reviewed and approved by the Board effective March 20, 2024.