Hemisphere ENERGY

ANNUAL INFORMATION FORM

For the year ended December 31, 2022

April 19, 2023

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APPENDICES

ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrels	Mcf	thousand cubic feet
bbl/d	barrels per day	Mcf/d	thousand cubic feet per day
bopd	barrels of oil per day	MMcf	million cubic feet
boe	barrels of oil equivalent	MMbtu	million British thermal units
boe/d	boe per day	Bcf	billion cubic feet
Mboe	thousand barrels of oil equivalent	GJ	gigajoule
Mbbl	thousand barrels		
NGL	natural gas liquids		

Other	
M$	thousands of dollars
$/boe	dollar per barrel of oil equivalent
$/bbl	dollar per barrel
$/MMbtu	dollar per million British thermal units
ha	Hectare
3D	three dimensional
API	American Petroleum Institute
^{o}API	an indication of the specific gravity of crude oil measured on the API gravity scale
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
m^3	Cubic metres
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	Bbl	6.289
feet	Metres	0.305
metres	Feet	3.281
miles	Kilometres	1.609
kilometres	Miles	0.621
acres	Hectares	0.405
hectares	Acres	2.471
gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

BARREL OF OIL EQUIVALENCY

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is misleading as an indication of value.

CURRENCY

All amounts are expressed in Canadian dollars unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, payment of dividends and share repurchases, the Company's tax pools and when the Company expects it may pay income taxes, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken in various areas, timing of drilling, recompletion and tie-in of wells, tax horizon, timing of development of undeveloped reserves, commodity prices and foreign exchange rates, planned capital expenditures, the timing thereof and the method of funding may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, changes in environmental or other legislation, reliance on key management personnel, changes in general economic and business conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "*Risk Factors*" and elsewhere herein. The recovery and reserve estimates of Hemisphere Energy Corporation's ("**Hemisphere**" or the "**Company**") reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. In addition, forward-looking statements may include statements attributable to third party industry sources. There can be no assurances that the plans, intentions, or expectations upon which such forward-looking statements are based will occur.

Forward-looking statements and information are based on a number of factors and assumptions which have been used to develop such statements and information, but which may prove to be incorrect. Although Hemisphere believes that the expectations reflected in such forward-looking statements and information are reasonable, undue reliance should not be placed on forward-looking statements because Hemisphere can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Hemisphere operates; the timely receipt of any required regulatory approvals; the ability of Hemisphere to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results, the ability of the operator of the projects which Hemisphere has an interest in to operate the project in a safe, efficient and effective manner; the ability of Hemisphere to obtain financing on acceptable terms; well production rates and decline rates; the ability to replace and expand the oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Hemisphere to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Hemisphere operates; and the ability of Hemisphere to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Hemisphere's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the System for Electronic Document Analysis and Retrieval ("**SEDAR**") at www.sedar.com and Hemisphere's website at www.hemisphereenergy.ca. Although the forward-looking statements and information contained herein are based upon what management believes to be reasonable assumptions, management cannot give assurance that actual results will be consistent with such forward-looking statements and information. Investors should not place undue reliance on forward-looking statements and information. These forward-looking statements and information are made as of the date of this annual information form ("**AIF**") and Hemisphere assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and information contained herein concerning the oil and gas industry and Hemisphere's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry, which Hemisphere believes to be reasonable. However, this data is inherently imprecise. While Hemisphere is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

NON-IFRS MEASURES

Within this AIF, references are made to terms commonly used in the oil and natural gas industry which do not have standardized measures prescribed by generally accepted accounting principles in Canada, including "operating field netback" and "operating netback". Operating field netback is a benchmark used in the oil and natural gas industry and a key indicator of profitability relative to current commodity prices. Operating field netback is calculated by the Company as oil and gas sales, less royalties, operating expenses and transportation costs on an absolute and per boe basis. Operating netback is calculated by the Company as the operating field netback plus the Company’s realized commodity hedging gain (loss) on an absolute and per barrel of oil equivalent basis. These terms should not be considered an alternative to, or more meaningful than, cash flow from operating activities or net income or loss as determined in accordance with International Financial Reporting Standards ("**IFRS**") as an indicator of the Company’s performance. The Company uses operating field netback and operating netback as key performance indicators and for operational and capital allocation decisions. Readers are cautioned, however, that operating field netback and operating netback do not have standardized measures prescribed by generally accepted accounting principles in Canada and as a result, the Company may calculate these measures differently than other companies, including its industry peers. Refer to the section entitled "Non-IFRS and Other Financial Measures" contained within the Company's MD&A for the year ended December 31, 2022, available on SEDAR at www.sedar.com, for additional disclosures relating to these non-IFRS measures.

CORPORATE STRUCTURE

Name, Address, Incorporation and Organization

Hemisphere Energy Corporation was incorporated under the laws of the Province of British Columbia on March 6, 1978 and is governed by the *Business Corporations Act* (British Columbia). The Company does not have any subsidiaries. Hemisphere's head office is located at Suite 501, 905 West Pender Street, Vancouver, British Columbia V6C 1L6 and its registered office is located at Harper Grey LLP, Suite 3200, 650 West Georgia Street, Vancouver, British Columbia V6B 4P7.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History of the Company

Fiscal year ended December 31, 2020

Due to the material weakening of global oil prices early in 2020 as a result of the COVID-19 (as defined herein) pandemic compounded by OPEC+, led by Saudi Arabia and Russia, failing to reach an agreement on constraining output, Hemisphere opted to defer any major capital spending until price recovery.

As of July 1, 2020, under the Normal Course Issuer Bid ("NCIB") announced on June 27, 2019, the Company had repurchased and canceled 320,000 common shares at an aggregate value of $55,593 during the first six months of 2020, for an average price of $0.17 per share. This brought the total shares purchased and canceled under the NCIB between July 1, 2019 and July 1, 2020 to 1,301,000 common shares at an aggregate value of $179,273, for an average price of $0.14 per share.

On June 29, 2020, the Company announced that the TSX Venture Exchange ("TSX-V") had accepted the Company's notice of intention to renew the NCIB to purchase and cancel up to 7,869,931 (approximately 10% of the public float of the Company's common shares at the time of announcement) through the facilities of the TSX-V. The renewal of the NCIB commenced on July 1, 2020 and expired on July 1, 2021. For the six-month period ended December 31, 2020, the Company had repurchased 1,800,000 common shares under the renewal of the NCIB at an aggregate value of $209,880, for an average price of $0.12 per share. This brought the total shares purchased and canceled during 2020 under the NCIB to 2,120,000 common shares at an aggregate value of $265,473, for an average price of $0.13 per share.

During 2020, the Company paid down US$6.0 million on its term loan, and otherwise funded its minimal capital program within cash flow. Capital spending included three injector conversions and significant planning and preparatory work for 2021 polymer conversion in Atlee Buffalo.

Fiscal year ended December 31, 2021

In April 2021, the Company began trading on the OTCQX Venture Marketplace, which made the Company more accessible to a broader range of U.S investors.

In July 2021, the Company announced the renewal of the Company's NCIB to purchase up to 7,687,830 of its common shares (approximately 10% of the public float of the Company's common shares at the time of announcement) through the facilities of the TSX-V. The NCIB commenced on July 14, 2021 and expires on July 13, 2022. No shares were repurchased in the six-month period ending December 31, 2021 under this NCIB renewal. However, for the twelve-month period ended December 31, 2021, the Company had repurchased 537,500 shares under the NCIB for $164,070, at an average price of $0.31.

The Company also announced the replacement of its previous five-year term loan with a new $35.0 million extendible two-year committed term facility with ATB Financial (the "Credit Facility").

Hemisphere incurred capital expenditures during the year of $12.0 million to drill 7 Atlee Buffalo wells (four of the seven wells were not brought online until early January), implement polymer flood at G pool, and expand production facilities to accommodate additional oil production.

During the year ended December 31, 2021, the Company issued 2,745,000 shares for stock options exercised through the Employee Stock Option Plan, at an average exercise price of $0.14 per share. In December 2021, the Company granted 1,740,000 incentive stock options at an exercise price of $0.91 each. Additionally in the fourth quarter, the warrant holder did a cashless exercise of 25% of its warrants at a $0.846 30-day VWAP, resulting in the issuance of 2,299,851 common shares for the exercise cost of 3,437,500 warrants at $0.28 per share. After this exercise the warrant holder had 10,312,500 exercisable warrants remaining.

Fiscal year ended December 31, 2022

In June 2022, the Company completed the renewal of its Credit Facility and the commencement of a quarterly variable dividend. Hemisphere's Board of Directors approved a variable dividend policy targeting approximately 30% of Hemisphere's annual free funds flow to be paid quarterly. Accordingly, the first ever quarterly cash dividend paid to Hemisphere shareholders was $0.025 per share on June 30, 2022, to shareholders of record as of the close of business on June 15, 2022.

In July 2022, the Company announced the renewal of the Company's NCIB to purchase up to 8,905,836 of its common shares (approximately 10% of the public float of the Company's common shares at the time of announcement) through the facilities of the TSX-V. The NCIB commenced on July 14, 2022 and expires on July 13, 2023. For the twelve-month period ended December 31, 2022, the Company repurchased 2,312,400 shares under the NCIB for $3.4 million, at an average price of $1.47 per share.

Significant Acquisitions

The Company did not make any significant acquisitions during 2022.

DESCRIPTION OF THE BUSINESS

General

Hemisphere produces oil and natural gas from its Jenner and Atlee Buffalo properties in southeast Alberta and is focused on developing conventional oil assets with low-risk drilling opportunities. The Company trades on the TSX-V as a Tier 1 issuer under the symbol "HME" and on the OTCQX Venture Marketplace under the symbol "HMENF".

Competition

The oil and gas industry is competitive in all its phases. The Company competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include resource companies that have greater financial resources, staff, and facilities than those of the Company. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Company believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access to the Company's oil and gas properties in certain circumstances.

Commodity Prices

The Company's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including, but not limited to, weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the Company's financial condition and such effect could be material. See *"Risk Factors"*.

Environmental Regulation

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. No assurance can be given that the application of environmental laws to the business and operations of the Company will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects. See *"Risk Factors"*.

Human Resources

As at December 31, 2022, Hemisphere had six full-time head office employees, one full-time Calgary employee, and one full-time field employee. Additionally, the Company had seven part-time consultants and four full-time field contractors.

Specialized Skill and Knowledge

The Company relies on specialized skills and knowledge to gather, interpret and process geophysical data, operate production facilities and numerous additional activities required to produce oil and natural gas. The Company has employed a strategy of contracting consultants and other service providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operations effectively.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business and the oil and natural gas business generally.

Exploration, Development and Production Risks

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

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

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

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills, and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Company may explore for and produce sour gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company.

Oil and natural gas production operations are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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

Prices, Markets and Marketing

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

The Company's ability to market its oil and natural gas may depend upon its ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contract for the delivery of crude oil by rail. Numerous factors beyond the Company's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Company, including:

- deliverability uncertainties related to the distance the Company's reserves are from pipelines, railway lines, processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and
- government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Company.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and the Company's ability to access such markets. A material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Company's reserves. The Company 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 Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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.

Market Price

The trading price of the common shares of the Company may be adversely affected by factors related and unrelated to the oil and natural gas industry.

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 the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices and, 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. Similarly, the market price of the common shares of the Company could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity, and other internal factors. Accordingly, the price at which the common shares of the Company will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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

Adverse Economic Conditions

Adverse general economic, business, and industry conditions could have a material adverse effect on the Company's results of operations and cash flow.

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

Political Uncertainty

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

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

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

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy.

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

Russian Ukrainian Conflict

The Russian Ukrainian conflict and the related sanctions imposed by many Western countries will impact the world economy and the supply of oil and natural gas as Russia is a significant exporter of both oil and natural gas.

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

In addition, in September 2022 the 1,200 km twin Nord Stream natural gas pipelines that were built to carry natural gas from Russia to Germany exploded underwater, likely as a result of sabotage. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply of energy and high prices of oil and natural gas could have a significant adverse impact on the world economy.

COVID-19 and its Effect on the Global Economy

The COVID-19 pandemic continues to cause disruptions in economic activity in Canada and internationally and impact demand for oil, NGL and natural gas.

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed nonessential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, liquids and natural gas. Since 2020, oil prices have largely recovered from their historic lows, and most countries have resumed full economic activity without any restrictions. However, certain countries, such as China, continue to experience varying degrees of virus outbreak. Any reduction in economic activity in certain countries resulting from COVID-19 outbreaks, government-imposed lockdowns and other restrictions may have a negative effect on demand for oil, NGL and natural gas.

Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on the Company's operational results and financial condition. Low prices for oil, NGL and natural gas will reduce the Company's funds from operations, and impact the Company's level of capital investment and may result in the reduction of production at certain producing properties.

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

Operational Dependence

The successful operation of a portion of the Company's properties is dependent on third parties

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

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

Project Risks

The success of the Company's operations may be negatively impacted by factors outside of its control resulting in operational delays and cost overruns.

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

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- 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, the Company could be unable to execute projects on time, on budget, or at all.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on the Company's ability to produce and sell its oil and natural gas

The Company delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Company can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. See "*Industry Conditions - Transportation Constraints and Market Access*" . In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Company's inability to realize the full economic potential of its products or in a reduction of the price offered for the Company's production. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Company's production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In August 2019, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force resulting in changes to the federal regulation and associated environmental assessments of major projects. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

In January 2021, U.S President Biden took steps to cancel the presidential permit that had allowed the Keystone XL Pipeline to operate across Canadian and American borders. It is unclear if challenges to the revocation of the permit will be successful and what the direct impact of the loss of permit will be on the Company.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Company's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Competition

The Company competes with other oil and natural gas companies, some of which have greater financial and operational resources.

The petroleum industry is competitive in all of its phases. The Company competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff, and facilities than those of the Company. 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 the Company. The Company's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its 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, and reliability of delivery and storage.

Cost of New Technologies

The Company's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete.

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

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Company's financial condition, results of operations and cash flow.

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

Regulatory

Modification to current, or implementation of additional, regulations may reduce the demand for oil and natural gas and/or increase the Company's costs and/or delay planned operations.

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

In order to conduct oil and natural gas operations, the Company will 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 the Company will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Company's business, financial condition and the market value of its common shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*"

Royalty Regimes

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

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

Waterflood

Regulatory water use restrictions and/or limited access to water or other fluids may impact the Company's production volumes from its waterflood operations.

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

Disposal of Fluids used in Operations

Regulations regarding the disposal of fluids used in the Company's operations may increase its costs of compliance or subject it to regulatory penalties or litigation.

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

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Company's financial and operational resources.

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

Climate Change

Climate change concerns could result in increased operating costs and reduced demand for the Company's products and shares, while the potential physical effects of climate change could disrupt the Company's production and cause it to incur significant costs in preparing for or responding to those effects

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, NGL 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, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact. As discussed below, the Company faces both transition risks and physical risks associated with climate change and climate change policy and 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, promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses, and, in the long-term, potentially reducing the demand for oil, NGL, natural gas and related products, resulting in a decrease in the Company's profitability and a reduction in the value of its assets.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including the Company, for alleged personal injury, property damage, or other potential liabilities. While the Company is not a party to any such litigation or proceedings, it could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by the Company, impact its operations and have an adverse impact on its financial condition.

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

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

Physical risks

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

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct of the Company's operations, development or exploratory activities may negatively impact the Company.

Opposition by Indigenous groups to the conduct of the Company's operations, development or exploratory activities in any of the jurisdictions in which the Company conducts business may negatively impact it in terms of public perception, diversion of management's time and resources, and legal and other advisory expenses, and could adversely impact the Company's progress and ability to explore and develop properties.

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

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Company's 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 have come to an agreement relating to further industrial activities in the area, which will have an impact on such industrial activities. The Government of British Columbia has also recently reach an agreement with four First Nations in northeast British Columbia to implement a system to manage the cumulative effects of development, implement new land-use plans and protection measures, and create a revenue sharing system with those First Nations. The developments in northeast 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 crude oil and natural gas industry and Hemisphere remain uncertain.

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

Inflation and Rising Interest Rates

A failure to secure the services and equipment necessary to the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and cash flows.

Recently in Canada, the United States and other countries there have been high levels of inflation, supply chain disruptions, equipment limitations and escalating supply costs. These factors have resulted in the escalation of operating costs of the Company. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows.

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

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 of combat inflation. The rise in interest rates may impact the Company's borrowing costs. Any increase in borrowing costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows of the Company. The rising interest rates could also result in a recession in Canada, the United States or other countries in the world. A recession may have a negative impact on demand for oil and natural gas which would result in a decrease in commodity prices. A decrease in commodity prices would immediately impact the Company's revenues and cash flows and could also reduce drilling activity on the Company's properties. It is unknown how long inflation will continue to impact the economies of Canada and the United States and the impact inflation and rising interest rates will have on demand for oil and gas and commodity prices.

Seasonality

Oil and natural gas operations are subject to seasonal weather conditions and the Company may experience significant operational delays as a result

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 transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Company's production if not otherwise tied-in. Certain of the Company's oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of impassable muskeg.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

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

Substantial Capital Requirements

The Company's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations and acquire and develop reserves.

The Company anticipates 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 cash generated from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors:

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

Further, if the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Company, to access additional financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The Company may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Additional Funding Requirements

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

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Company may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Company 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, the Company may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Company's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Credit Facility Arrangements

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

The Company currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Company is required to comply with covenants under its credit facilities and in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with covenants could result in default under the

Company's credit facilities, which could result in the Company being required to repay amounts owing thereunder. The acceleration of the Company's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Company's credit facilities impose certain operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Company's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Company's lenders use the Company's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Company's borrowing base, under its credit facility. Commodity prices have recently increased but they remain volatile as a result of various factors including limited egress options for Western Canadian oil and natural gas producers, global geo-political tensions, actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce the Company's borrowing base, reducing the funds available to the Company under its credit facilities. This could result in the requirement to repay a portion, or all, of the Company's indebtedness. If the Company's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under its credit facilities, such financing may not be on commercially reasonable terms, or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under its credit facilities, the lenders under such credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

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

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

Hedging

Hedging activities expose the Company to the risk of financial loss and counterparty risk

From time to time, the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes 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, the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Company will not benefit from the fluctuating exchange rate.

Title to and Right to Produce from Assets

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

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

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

Reserves Estimates

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

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

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

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

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

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

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

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Company.

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

Non-Governmental Organizations

The Company's properties may be subject to action by non-governmental organizations or terrorist attack.

The oil and natural gas exploration, development and operating activities conducted by the Company may, at times, be subject to public opposition. Such public opposition could expose the Company 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. See "*Industry Conditions – Transportation Constraints and Market Access*". There is no guarantee that the Company will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Company to incur significant and unanticipated capital and operating expenditures.

Reputational Risk Associated with the Company's Operations

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

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

Changing Investor Sentiment

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

A number of factors, including the effects of the use of fossil fuels on climate change, 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 towards 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 the Company's Board of Directors, management, and employees of the Company. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Company, or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Company's asset which may result in an impairment change.

Dilution

The Company may issue additional common shares, diluting current shareholders.

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

Management of Growth

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

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

Expiration of Licenses and Leases

The Company, or its working interest partners, may fail to meet the requirements of a licence or lease, causing its termination or expiry.

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

Dividends

The Company's dividends may be reduced or suspended at any time. The amount of future cash dividends declared and paid by the Company, if any, is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, capital expenditure requirements, debt service requirements, operating costs, foreign exchange rates and the satisfaction of certain covenants and restrictions under the Company's credit facilities and 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 Company, the dividend policy of the Company may change from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

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

To the extent that external sources of capital become limited or unavailable, the ability of the Company to make its necessary capital investments in its business will be impaired. To the extent that the Company is required to use funds from operations to finance capital expenditures or invest in or further expand its asset base, the cash available for dividends may be reduced. See "*Dividends*".

Litigation

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

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

Breach of Confidentiality

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

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

Income Taxes

Taxation authorities may reassess the Company's tax returns.

The Company files all required income tax returns and believes that it is 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 the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

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

Third Party Credit Risk

The Company is exposed to credit risk of third-party operators or partners of properties in which it has an interest.

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

Conflicts of Interest

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

Certain directors or officers of the Company 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 *Business Corporations Act* (Alberta) (the "**ABCA**") which require a director or officer of a company who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel may negatively impact the Company.

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

Competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. The Company does not have any key personnel insurance in effect.

Contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. If the Company is unable to: (i) retain current employees; and/or (ii) recruit new employees with the requisite knowledge and experience, the Company could be negatively impacted. In addition, the Company could experience increased costs to retain and recruit these professionals.

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

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on Hemisphere, its customers, and/or either of their businesses or operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses (including, most recently, the novel coronavirus (COVID-19), civil unrest (including the most recent protests and railway blockades in Canada) and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to Hemisphere, its customers, and/or either of their businesses or operations.

Information Technology Systems and Cyber-Security

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

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

Further, the Company is subject to a variety of information technology and system risks as a part of its operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company’s information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information, or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware. The ongoing COVID-19 pandemic has increased the Company's cyber-attacks, as increased malicious activities are creating more threats for cyberattacks including COVID-19 phishing emails, malware-embedded mobile apps that purport to track infection rates, and targeting of vulnerabilities in remote access platforms as many companies continue to operate with work from home arrangements.

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

Social Media

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

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

Expansion into New Activities

Expanding the Company's business exposes it to new risks and uncertainties.

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

Forward-Looking Information

Forward-Looking Information May Prove Inaccurate.

Shareholders and prospective investors are cautioned not to place undue reliance on the Company's forward-looking 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 Statements*" in this AIF.

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) as a result of legislation enacted by 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 the Company is unable to predict what additional legislation or amendments governments may enact in the future.

The Company holds interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian province of Alberta. The Company's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of the Company's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells 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 crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. 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. While these matters do not affect the Company's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such matters carefully.

Pricing and Marketing in Canada

Crude Oil

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

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("**OPEC**") forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's zero-COVID policy. OPEC predicts global oil demand to rise by 2.25 million barrels per day in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of oil and gas from the region. In addition, certain countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near term effects on Russia. The long-term impacts of the conflict remain uncertain.

Natural Gas

Negotiations between buyers and sellers determine the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids ("NGLs")

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

Exports from Canada

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the Canadian Energy Regulator Act (the "**CERA**"). Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Company does directly enter into contracts to export its production outside of Canada.

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. Although certain pipeline and other transportation projects have been announced or are underway, 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.

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

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

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2022. The pipeline is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's initial December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge Inc. stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General intends to appeal the decision.

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

Natural Gas and Liquefied Natural Gas ("LNG")

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

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

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Phase 1 of the LNG Canada project reached 70% completion in October 2022, with a completion target of 2025.

In May 2020, TC Energy Corporation sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its regulatory approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of November 2022, construction of the CGL Pipeline is approximately 80% complete.

Woodfibre LNG Limited issued a notice to proceed with construction of the Woodfibre LNG project to its prime contractor in April 2022. The Woodfibre LNG project is located near Squamish, British Columbia, and upon completion will produce approximately 2.1 million tonnes of LNG per year. Major construction is set to commence in 2023, with substantial completion of the project expected in late 2027. In November 2022, Enbridge Inc. completed a transaction with Pacific Energy Corporation Limited, the owner of Woodfibre LNG Limited, to retain a 30% ownership stake in the project.

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

Marine Tankers

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

International Trade Agreements

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

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

Canada is also party to the CETA, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"), which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

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

Land Tenure

Mineral rights

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

In response to COVID-19, the Government of Alberta, among others, announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures.

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

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

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the Indian Act (Canada). Indian Oil and Gas Canada manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations through An Act to Amend the Indian Oil and Gas Act and the accompanying regulations.

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, including notification requirements and providing compensation to affected persons for lost land use and surface damage. Similar rules apply to facility and pipeline operators.

Royalties and Incentives

General

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. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and 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.

Occasionally, both the federal government and the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance. In addition, from time-to-time, including during the COVID-19 pandemic, the federal government creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry as well as other industries in Canada.

Alberta

Crown royalties

In Alberta, oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation.

In 2016, the Government of Alberta adopted a modernized Crown royalty framework (the "**Modernized Framework**") that applies to all conventional oil (i.e., not oil sands) and natural gas wells drilled after December 31, 2016 that produce Crown-owned resources. The previous royalty framework (the "**Old Framework**") will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026, following which time they will become subject to the Modernized Framework. The Royalty Guarantee Act (Alberta), came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

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

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

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

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

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. Producers and working interest participants may also pay additional royalties to parties other than the freehold mineral owner where such royalties are negotiated through private transactions.
The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

Incentives

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Regulatory Authorities and Environmental Regulation

General

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.

Federal

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

The CERA and the Impact Assessment Act (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

Alberta

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

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

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

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

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**") The Company does not have operations in Fox Creek, Red Deer and Brazeau.

Liability Management

Alberta

The AER administers the Liability Management Framework (the "**AB LM Framework**") and the Liability Management Rating Program (the "**AB LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. This change was effected under key new AER directives in 2021, and further updates released in 2022. Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

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

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

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

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

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry-wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target. The AER has also indicated that it will implement a closure nomination program (the "**CN Program**") in 2023. Under the program, those who qualify may nominate certain oil and gas sites for closure. Details regarding the CN Program and the mechanism through which nominated sites will be abandoned and reclaimed are forthcoming.

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

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

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 the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

In line with the Prime Minister's pledge to impose a cap on emissions from the oil and gas sector, the federal government published a discussion paper on July 18, 2022 that outlines two potential regulatory options for such a cap. Those proposed options are either to: (i) implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. These options are currently under review and interested parties had the opportunity to make submissions regarding the proposed cap, ending in September 2022. The form of emissions cap on the oil and gas sector and the overall effect of such a cap remain uncertain.

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. This 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 CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $65/tonne of CO2e.

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 a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

The 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 for Canada's reduction of 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.

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 Clean Fuel Regulations came into force, establishing Canada's Clean Fuel Standard. The Clean Fuel Standard will replace the former Renewable Fuels Regulation, and aims to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives. Coming into force in 2023, the Clean Fuel Standard will impose obligations on primary suppliers of transportation fuels in Canada and require 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).

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. Beginning in 2022, the federal government plans to spend $319 million over seven years to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

Alberta

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

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On January 1, 2023, the carbon tax payable in Alberta increased from $50 to $65 per tonne of CO_2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved Alberta's Technology Innovation and Emissions Reduction ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 (as amended on 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 TIER regulation applies to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 2% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports. Facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the Methane Emission Reduction Regulation on January 1, 2020, and 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.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the Declaration on the Rights of Indigenous Peoples Act ("**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. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, 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, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

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

On June 29, 2021, the British Columbia Supreme Court issued a judgement in Yahey v British Columbia (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("**BRFN**") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. 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 the 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. The 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.

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, Salteau, 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 the 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. The long-term impacts of the Blueberry Decision and the Duncan's First Nation lawsuit on the Canadian oil and gas industry remain uncertain.

STATEMENT OF RESERVES AND OTHER OIL AND NATURAL GAS INFORMATION

In accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and Canadian Oil and Gas Evaluation Handbook reserve definitions, McDaniel & Associates Consultants Ltd. ("**McDaniel**") prepared a report for the Company dated February 15, 2023 with an effective date of December 31, 2022 (the "**McDaniel Report**"). The McDaniel Report evaluated Hemisphere's oil, NGL and natural gas reserves. All properties evaluated are in Canada and specifically in Alberta and British Columbia. The Reserves Committee of the Board of Directors has reviewed and approved the McDaniel Report. The *Report on Reserves Data by the Independent Qualified Reserves Evaluator* and *Report of Management and Directors on Oil and Gas Disclosure* are attached as Appendices "A" and "B" hereto, respectively.

The tables below are a summary of the oil, NGL and natural gas reserves attributable to Hemisphere's properties and the net present values of future net revenue attributable to such reserves as evaluated in the McDaniel Report based on forecast price and certain cost assumptions. The tables summarize the data contained in the McDaniel Report and, as a result, may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly.

The net present values of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and all corporate liabilities. It should not be assumed that the undiscounted or discounted net present values of future net revenue attributable to reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGL, and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The McDaniel Report is based on certain factual data supplied by the Company and McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to McDaniel. McDaniel accepted this data as presented and neither title searches nor field inspections were conducted by McDaniel.

Readers should review the definitions and information contained in "*Additional Information Relating to Reserve Data*" below in conjunction with the following tables and notes. The recovery and reserve estimates on Hemisphere's properties described herein are estimates only. The actual reserves on Hemisphere's properties may be greater or less than those calculated. See "*Risk Factors*".

Summary of Oil and Natural Gas Reserves and Net Present Values of Future Net Revenue

As of December 31, 2022
Forecast Prices and Costs
Reserves Summary

	Heavy Crude Oil		**Conventional Natural Gas**	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Reserves Category	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)
Proved				
Developed Producing	8,162.8	6,494.2	130.4	116.5
Developed Non-Producing	82.3	70.0	92.7	82.2
Undeveloped	3,846.5	3,172.7	255.1	231.6
Total Proved	**12,091.6**	**9,736.9**	**478.2**	**430.4**
Total Probable	3,836.0	2,968.0	165.9	147.0
Total Proved Plus Probable	**15,927.6**	**12,704.9**	**644.0**	**577.4**

Notes:
(1) Gross reserves are the Company's working interest reserves before royalty deductions and without including any royalty interests.
(2) Net reserves are the Company's working interest reserves after royalty deductions plus any royalty interest reserves.

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

Reserves Category	0% M$	5% M$	10% M$	15% M$	20% M$	Unit Value Before Income Tax Discounted at 10% per year $/boe[1]
Proved						
Developed Producing	324,740.8	268,695.7	227,669.2	197,610.3	174,957.9	27.82
Developed Non-Producing	1,042.1	890.5	770.2	673.5	594.7	7.88
Undeveloped	136,170.4	103,293.1	80,079.7	63,273.8	50,813.0	20.59
Total Proved	**461,953.2**	**372,879.2**	**308,519.2**	**261,557.7**	**226,365.6**	**25.35**
Probable	166,408.8	116,215.3	86,828.8	68,149.1	55,480.6	22.47
Total Proved Plus Probable	**628,362.0**	**489,094.6**	**395,347.9**	**329,706.7**	**281,846.2**	**24.65**

Note:
(1) The unit values are based on working interest gross reserve volumes.

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

	0% M$	5% M$	10% M$	15% M$	20% M$
Proved					
Developed Producing	254,969.8	212,316.1	180,358.2	156,772.8	138,942.8
Developed Non-Producing	802.3	682.1	587.5	511.9	450.5
Undeveloped	104,754.1	78,699.9	60,355.3	47,114.9	37,330.4
Total Proved	**360,526.2**	**291,698.1**	**241,301.0**	**204,399.5**	**176,723.7**
Probable	128,573.5	89,519.5	66,746.2	52,303.9	42,524.1
Total Proved Plus Probable	**489,099.7**	**381,217.5**	**308,047.2**	**256,703.4**	**219,247.8**

Total Future Net Revenue
(Undiscounted)
As of December 31, 2022
Forecast Prices and Costs

Reserves Category	Revenue[(1)] M$	Royalties[(2)] M$	Operating Costs M$	Development Costs M$	Abandon-ment & Reclamation Costs[(3)] M$	Future Net Revenue Before Income Taxes M$	Income Taxes M$	Future Net Revenue After Income Taxes M$
Total Proved	943,544	182,159	238,945	45,087	15,399	461,953	101,427	360,526
Total Proved plus Probable	1,269,186	254,639	319,734	50,515	15,936	628,362	139,262	489,100

Notes:
(1) Includes all product revenues and other revenues as forecast.
(2) Royalties includes any net profits interests paid.
(3) Abandonment and reclamation costs have been included by McDaniel for all wells (both existing and undrilled) and facilities of the Company. See "Abandonment and Reclamation Costs" below.

Future Net Revenue by Product Type
As of December 31, 2022
Forecast Prices and Costs

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%) M$	Unit Value[(1)] $/bbl
Proved	Heavy Crude Oil (including solution gas and by-products)	308,519	31.69
Proved Plus Probable	Heavy Crude Oil (including solution gas and by-products)	395,348	31.12

Note:
(1) Unit values are calculated using the 10% discount rate divided by the net reserves for each product type.

Pricing Assumptions

The forecast cost and price assumptions in this statement for the Company's reserves assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas forecast pricing, inflation and exchange rates utilized in the McDaniel Report were based on a 3-Consultant average of the January 1, 2023 price forecasts from McDaniel, GLJ Petroleum Consultants Ltd., and Sproule Associates Ltd. and are detailed as follows:

Summary of Pricing and Inflation Rate Assumptions
Forecast Prices and Costs
As at January 1, 2023

Year	WTI Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Western Canadian Select Crude Oil ($Cdn/bbl)	Alberta AECO Spot Price ($Cdn/MMBtu)	Inflation (%)	US/Cdn Exchange Rate ($US/$Cdn)
2023	80.33	103.76	76.54	4.23	0.0	0.745
2024	78.50	97.74	77.75	4.40	2.3	0.765
2025	76.95	95.27	77.55	4.21	2.0	0.768
2026	77.61	95.58	80.07	4.27	2.0	0.772
2027	79.16	97.07	81.89	4.34	2.0	0.775
2028	80.74	99.01	84.02	4.43	2.0	0.775
2029	82.36	100.99	85.73	4.51	2.0	0.775
2030	84.00	103.01	87.44	4.60	2.0	0.775
2031	85.69	105.07	89.20	4.69	2.0	0.775
2032	87.40	106.69	91.11	4.79	2.0	0.775
2033	89.15	108.83	92.93	4.88	2.0	0.775
2034	90.93	111.00	94.79	4.98	2.0	0.775
2035	92.75	113.22	96.69	5.08	2.0	0.775
2036	94.61	115.49	98.62	5.18	2.0	0.775
2037	96.50	117.80	100.59	5.29	2.0	0.775
Thereafter	Escalation Rate of 2%/year				2.0	0.775

The weighted average sales prices realized by Hemisphere for the year ended December 31, 2022 were $94.29/bbl for heavy crude oil and $5.03/Mcf for conventional natural gas.

Reserves Reconciliation
Reconciliation of Gross Reserves
By Product Type
Forecast Prices and Costs

	Heavy Crude Oil			Conventional Natural Gas			Natural Gas Liquids			Boe		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
Dec. 31, 2021	**11,938.1**	**3,753.8**	**15,691.9**	**82.4**	**35.5**	**117.9**	**-**	**-**	**-**	**11,951.8**	**3,759.8**	**15,711.6**
Extensions and improved recovery	738.3	238.5	976.8	0.7	0	0.7	-	-	-	738.5	238.4	976.9
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	103.7	17.0	120.7	59.9	4.3	64.2	-	-	-	113.7	17.7	131.4
Technical Revisions	237.4	(291.1)	(53.7)	100.0	14.0	114.0	-	-	-	253.7	(278.8)	(25.1)
Technical Revisions - LOS	(47.3)	(28.4)	(75.7)	30.1	7.4	37.5	-	-	-	(42.3)	(27.1)	(69.4)
Technical Revisions - Transfer	11.9	(107.0)	(95.1)	3.2	(5.3)	(2.1)	-	-	-	12.4	(107.9)	(95.5)
Technical Revisions - Non producing	-	-	-	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	131.8	253.4	385.2	262.2	106.2	368.4	-	-	-	175.5	271.1	446.6
Production	(1,022.4)	-	(1,022.4)	(57.7)	0	(57.7)	-	-	-	(1,032.0)	-	(1,032.0)
Dec. 31, 2022	**12,091.6**	**3836.0**	**15,927.6**	**478.2**	**165.8**	**644.0**	**-**	**-**	**-**	**12,171.3**	**3863.6**	**16,034.9**

Undeveloped Reserves

Undeveloped reserves were attributed in accordance with the standards and procedures in the Canadian Oil and Gas Evaluation Handbook.

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to the Company's assets for the years ended December 31, 2022, 2021, and 2020 based on forecast prices and costs.

	Heavy Crude Oil		Conventional Natural Gas	
	First Attributed Gross (Mbbl)	Cumulative at Year End Gross (Mbbl)	First Attributed Gross (MMcf)	Cumulative at Year End Gross (MMcf)
Proved Undeveloped				
December 31, 2020	2,635.3	7,081.1	-	4.8
December 31, 2021	1,156.5	4,501.0	-	-
December 31, 2022	736.0	3,846.5	255.1	255.1
Probable Undeveloped				
December 31, 2020	559.1	1,907.6	-	15.8
December 31, 2021	681.7	1,717.7	-	-
December 31, 2022	449.7	1652.4	104.5	104.5

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

The Company currently plans to pursue the development of its proven and probable undeveloped reserves within the next five years through ordinary course capital expenditures. However, a number of factors could result in delayed or cancelled development (including the delay or development of the undeveloped reserves beyond five years from the date such undeveloped reserves are first attributed) which may include:

- impact of commodity prices as a substantial and extended decline in the price of oil and natural gas would have an adverse effect on, among other things, the Company's revenues and financial condition and consequently, its ability to finance the development of its undeveloped reserves;
- other changing economic conditions (due to royalties, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion);
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability and pricing of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserves estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, product pricing, capital expenditures, operating costs, royalty regimes, abandonment, and reclamation costs and well performance, all of which are beyond the control of the Company. These revisions can be either positive or negative and are often required due to changes in well and reservoir performance, geologic conditions, commodity prices, economic conditions and/or government restrictions. Degradation in future commodity price forecasts relative to the forecast in the McDaniel Report can also have a negative impact on the economics and timing of development of undeveloped reserves, unless significant reduction in the future costs of development are realized.

With regard to the particular components of the Company's reserves data, the Company does not anticipate any unusually high development costs or operating costs, nor does the Company have any contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

See also "*Pricing Assumptions*", "*Abandonment and Reclamation Costs*" and "*Risk Factors*".

Abandonment and Reclamation Costs

As at December 31, 2022, Hemisphere had 137.7 net wells for which abandonment and reclamation costs are expected to be incurred over the next forty-one years. There are no unusually significant abandonment and reclamation costs associated with Hemisphere's properties.

In estimating the future net revenues disclosed in this AIF, the McDaniel Report deducted: (i) $15.9 million (undiscounted) and $3.0 million (10% discount) for abandonment and reclamation costs in the proved plus probable reserves category; and (ii) $15.4 million (undiscounted) and $3.0 million (10% discount) for abandonment and reclamation costs in the proved reserves category. These cost estimates account for all of Hemisphere’s existing corporate liabilities, in addition to those estimated for future undeveloped locations. Treatment of estimated abandonment and reclamation costs is consistent with changes made to guidance in the Canadian Oil and Gas Handbook (COGEH) in 2019, where recommended industry practice is to include all abandonment and reclamation costs associated with both active and inactive wells and facilities.

The Company’s decommissioning obligations are estimated based on its net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future years. The Company uses the AER's guidelines for determining abandonment and reclamation estimates.

Additional information related to the Company's estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities and infrastructure) can be found in Hemisphere's audited financial statements for the year ended December 31, 2022 and the accompanying management's discussion and analysis, which have been filed on SEDAR and may be viewed under the Company's profile at www.sedar.com.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to the reserves categories noted below.

	Forecast Prices and Costs	
	Proved Reserves M$	Proved Plus Probable Reserves M$
2023	13,217	13,217
2024	16,762	16,762
2025	11,165	11,165
2026	1,692	7,120
2027	2,251	2,251
Remaining	-	-
Total (Undiscounted)	**45,087**	**50,515**

Hemisphere typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate, and new equity issues, if available on favourable terms.

Estimates of reserves and future net revenues have been made assuming the development of each property, in respect of which the estimate is made, will occur without regard to the likely availability to the Company of funding required for the development. There can be no guarantee that funds will be available or that the Company will allocate funding to develop all of the reserves attributed in the McDaniel Report. Failure to develop all of those reserves would have a negative impact on future funds from operations.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

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

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserve definitions.

"**by-product**" means a substance that is recovered as a consequence of producing a product type.

"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 capital expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

"fair market value" means the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

"future net revenue" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"gas" or **"natural gas"** or **"conventional natural gas"** means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional, or erosional geological features.

"gross" means:

(a) in relation to the Company's interest in production or reserves, its "Company gross reserves", which are the Company's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;
(b) in relation to wells, the total number of wells in which the Company has an interest; and
(c) in relation to properties, the total area of properties in which the Company has an interest.

"**heavy crude oil**" means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity.

"**natural gas liquids**" **or** "**NGLs**" means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

"net" means:

(a) in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves;
(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"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.

"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.

"solution gas" means gas dissolved in crude oil.

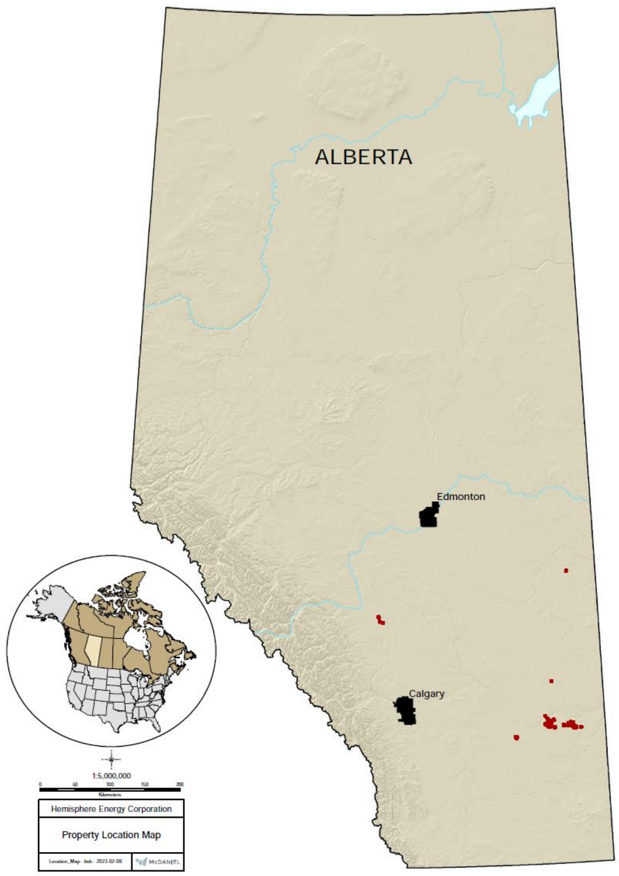
"undeveloped reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.

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

OTHER OIL AND GAS INFORMATION

Description of Oil and Gas Properties

Hemisphere's oil and gas properties at December 31, 2022 are located in Alberta. The following map identifies the location of the Company's assets:



Core Assets

The Company has two producing assets located in southeast Alberta.

Atlee Buffalo

Atlee Buffalo is Hemisphere's core area, located approximately 85 kilometers north of Medicine Hat. Hemisphere made its first acquisition in the area in late 2013 and owns 16,040 gross acres (16,040 net acres) as of December 31, 2022. The property has two oil pools delineated by vertical wells and defined by 3D seismic.

At December 31, 2022, the McDaniel Report assigned total proved plus probable reserves of 14,844.9 Mbbl of heavy crude oil and no gas. The Company held an interest in 13,240 gross acres (13,240 net acres) of undeveloped land in the Atlee Buffalo area as of December 31, 2022.

Jenner

Jenner is located 25 kilometers southwest of Atlee Buffalo. Hemisphere first entered the area in 2010 and owns 11,250 gross acres (10,239 net acres) as of December 31, 2022. The property has eight oil pools defined by 3D seismic. There is one Hemisphere-owned-and-operated oil processing and water disposal facility in Jenner with the capability for expansion.

At December 31, 2022, the McDaniel Report assigned total proved plus probable reserves of 1,016.4 Mbbl of heavy crude oil and 312.7 MMcf of conventional natural gas to the Company's Jenner property area. The Company held an interest in 7,890 gross acres (7,519 net acres) of undeveloped land in the Jenner area as of December 31, 2022.

Non-Core Assets

Hemisphere also has various working interests in five other non-core assets located in southern Alberta (Bantry, Heathdale, Sylvan Lake, and Wainwright). At December 31, 2022, the McDaniel Report assigned total proved plus probable reserves of 66.3 Mbbl of heavy crude oil and 331.3 MMcf of conventional natural gas to the Company's non-core properties. The Company held an interest in 6,720 gross acres (2,568 net acres) of land, of which 4,000 gross acres (1,840 net acres) are undeveloped in its non-core asset property areas as of December 31, 2022.

Oil and Natural Gas Wells

The following table summarizes Hemisphere's interest as at December 31, 2022 in wells that are producing and non-producing:

	Producing Wells(1)				**Non-Producing Wells(1,2,3)**			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta								
Atlee Buffalo	34	34	1	1	8	8	1	1
Jenner	6	6	-	-	16	16	1	1
Heathdale	-	-	-	-	-	-	-	-
Sylvan Lake	-	-	-	-	-	-	3	0.45
Wainwright	-	-	-	-	-	-	1	0.68
Total	**40**	**40**	**1**	**1**	**24**	**24**	**6**	**3.13**

Notes:

(1) *Does not include injection, disposal, source, observation, or abandoned wells.*
(2) *The Company has attributed oil reserves to 19% of its non-producing oil wells and has not attributed any reserves to its non-producing natural gas wells. The reserves attributed to these non-producing oil wells represent approximately 1% of the*

Company's total proved (net) reserves. Each of these non-producing wells are tied into existing pipelines and/or facility infrastructure. The period for which these non-producing wells have been off production varies from less than 1 year to several years.

(3) The non-producing wells currently capable of production that are not currently producing will be considered to be placed on production, from time to time, with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Exploration and Development Activities

The following table summarizes Hemisphere's exploratory and developmental drilling activities during the year ended December 31, 2022:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	-	-	7	7
Gas	-	-	-	-
Water Injector	-	-	1	1
Service Well	-	-	-	-
Stratigraphic Test Well	-	-	-	-
Dry Hole	2	1	-	-
Total	**2**	**1**	**8**	**8**

Production History

	Three Months Ended				Year Ended
	Mar. 31, 2022	Jun. 30, 2022	Sept. 30, 2022	Dec. 31, 2022	Dec. 31, 2022
Average daily production					
Heavy crude oil (bbl/d)	2,624	2,856	2,838	2,884	2,801
Conventional natural gas (Mcf/d)	141	165	189	138	158
Combined (boe/d)	2,648	2,883	2,870	2,907	2,828
Average sales prices					
Heavy crude oil ($/bbl)	96.53	117.37	90.39	73.52	94.29
Conventional natural gas ($/Mcf)	4.49	6.93	3.98	4.76	5.03
Combined ($/boe)	95.92	116.65	89.66	73.16	93.69

Operating netback ($/boe)					
Petroleum and natural gas revenue	95.92	116.65	89.66	73.16	93.69
Royalties	(19.80)	(34.14)	(24.19)	(16.50)	(23.71)
Operating costs	(8.95)	(8.88)	(13.12)	(13.16)	(11.09)
Transportation costs	(2.37)	(2.39)	(2.40)	(2.64)	(2.43)
Operating field netback(1)	64.89	71.25	49.95	40.86	56.46
Realized commodity hedging gain (loss)	(14.54)	(9.71)	(2.78)	1.76	(6.08)
Operating netback(2)	50.35	61.54	47.17	42.62	50.38

Notes:

(1) Operating field netback per boe is a non-IFRS measure calculated as the Company's oil and gas sales, less royalties, operating expenses and transportation costs per barrel of oil equivalent.

(2) Operating netback is a non-IFRS measure calculated as the operating field netback plus the Company's realized commodity hedging gain (loss) per barrel of oil equivalent.

Production Estimates

The following table discloses, by product type, the total volume of production estimated by McDaniel for the year ending December 31, 2023 in the estimates of future net revenue from Proved and from Probable Reserves disclosed under "*Statement of Reserves and Other Oil and Natural Gas Information*".

Proved	**Heavy Crude Oil** (bbl/d)	**Conventional Natural Gas** (Mcf/d)	**Total** (boe/d)
Alberta			
Atlee Buffalo	3,451	-	3,451
Jenner	115	138	138
Total	**3,566**	**138**	**3,590**

Proved Plus Probable	Heavy Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Total (boe/d)
Alberta			
Atlee Buffalo	3,663	-	3,663
Jenner	115	138	138
Total	**3,782**	**138**	**3,805**

Land Holdings Including Properties with No Attributed Reserves

The following table summarizes, by province, Hemisphere's developed and undeveloped landholdings as at December 31, 2022:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	**Gross**	**Net**
Alberta						
Atlee Buffalo	2,800	2,800	6,680	6,680	**9,480**	**9,480**
Atlee SE	-	-	6,560	6,560	**6,560**	**6,560**
Bantry	-	-	3,360	1,680	**3,360**	**1,680**
Heathdale	160	-	640	160	**800**	**160**
Jenner	3,360	2,720	7,890	7,519	**11,250**	**10,239**
Sylvan Lake	1,920	288	-	-	**1,920**	**288**
Wainwright	640	440	-	-	**640**	**440**
Total	**8,880**	**6,248**	**25,130**	**22,599**	**34,010**	**28,847**

The following table summarizes Hemisphere's unproven lands for which the Company expects its rights to explore, develop and exploit are scheduled to expire in 2023, if not continued:

Location	Acreage	
	Gross	**Net**
Atlee Buffalo	3,040	3,040
Heathdale	640	640

The Company plans to submit applications to continue portions of the above acreage.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Changes in future commodity prices could have a negative impact on the development of the Company's properties with no attributed reserves. See "*Risk Factors*" in this AIF for further discussion of economic and risk factors relevant to the Company's properties with no attributed reserves.

The Company does not anticipate any significant abandonment and reclamation costs or any unusually high development or operating costs that have affected or are reasonably expected to affect the anticipated development or production activities on the Company's properties which have no attributed reserves, nor does the Company have any contractual obligations to produce or sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Forward Contracts

As at December 31, 2022, Hemisphere had the following commodity contracts in place:

Product	Type	Volume	Price	Index	Term	Dec. 31, 2022 Fair Value $
Crude oil	Put Spread	750 bbl/d	US$50.00 (put sell) / US$60.00 (put buy), net cost US$2.50/bbl	WTI-NYMEX	January 1, 2023 – March 31, 2023	(195,496)
Crude oil	Put Spread	500 bbl/d	US$50.00 (put sell) / US$60.00 (put buy), net cost US$2.95/bbl	WTI-NYMEX	April 1, 2023 – June 30, 2023	(106,580)
Crude oil	Put Spread	500 bbl/d	US$50.00 (put sell) / US$60.00 (put buy), net cost US$3.70/bbl	WTI-NYMEX	July 1, 2023 – September 30, 2023	(105,067)
					Total	(416,818)

Taxes

The Company has approximately $28 million (December 2021 - $54 million) of tax pools available to be applied against future income for tax purposes as of December 31, 2022. Based on the Company's increased taxable income, available pools and current commodity prices, the Company has recorded a current tax expense of $0.2 million and deferred tax expense of $8.1 for the year ended December 31, 2022. The current tax expense includes an adjustment of $1.1 million in the fourth quarter to reduce the original current tax estimates for accelerated CDE and other tax deductions. The Company expects to incur additional income tax payable in 2023 and any taxes payable beyond this will primarily be a function of commodity prices, capital expenditures and production volumes.

		Years Ended December 31		
($000s, except per boe)		**2022**		2021
Current tax expense	**$**	**212**	$	-
Deferred tax expense		**8,131**		-
$ per boe – Current tax expense	**$**	**0.21**	$	-

($000s)	Deduction Rate	**December 31, 2022**	December 31, 2021
Canadian exploration expense (CEE)	100%	**$ -**	$ 3,337
Canadian development expense (CDE)	30%	**22,620**	18,235
Canadian oil and gas property expense (COGPE)	10%	**3,720**	3,995
Non-capital losses carry forwards (NCL)	100%	**-**	27,600
Undepreciated capital cost (UCC)	20-55%	**760**	612
Share issuance costs and other	Various	**660**	698
Total		**$ 27,760**	$ 54,477

Costs Incurred

The following table summarizes Hemisphere's property acquisition costs, exploration costs and development costs for the year ended December 31, 2022:

	Property Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total	**-**	**206,360**	**1,141,480**	**16,917,401**

DIVIDENDS AND SHARE REPURCHASES

Dividends

On June 7, 2022, the Company's Board of Directors approved a variable dividend policy targeting approximately 30% of Hemisphere's annual free funds flow to be paid quarterly. Accordingly, the Company paid its first ever quarterly cash dividend of $2.6 million on June 30, 2022 to Hemisphere shareholders at $0.025 per share.

The amount of future cash dividends declared and paid by Hemisphere, if any, will be subject to the discretion of the Company's Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including business performance, financial condition, growth plans, fluctuations in commodity prices, production levels, expected capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, interest rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Hemisphere or any of its subsidiaries is a party from time to time (including, without limitation, the agreements governing the credit facilities and other debt instruments of Hemisphere and its subsidiaries), and the satisfaction of liquidity and solvency tests imposed by the *Business Corporations Act* (British Columbia) for the declaration and payment of dividends. For more information regarding Dividends, refer to "*Risk Factors – Dividends*". The Board of Directors intends to review the Company's dividend policy from time to time, at its discretion. Depending on the foregoing factors and any other factors that the Board deems relevant from time to time, many of which are beyond the control of Hemisphere, the Board of Directors may change this policy following any such review or at any other time that the Board deems appropriate. Any such change may include, without restriction, future cash dividends being reduced or suspended entirely.

The following table sets forth the cash dividends declared by the Company for the dates indicated since its initiation in June 2022:

Record Date	Payment Date	Dividend price per common share
June 15, 2022	June 30, 2022	$0.025
August 31, 2022	September 7, 2022	$0.025
November 23, 2022	November 30, 2022	$0.025
February 10, 2023	February 21, 2023	$0.025

Normal Course Issuer Bid

The Company initiated the NCIB because it believed that, from time to time, the market price of its common shares may not properly reflect the underlying, intrinsic value of the Company, and that, at such times, the purchase of common shares for cancellation will increase the proportionate interest of, and be advantageous to, all remaining shareholders. Purchases of common shares under the NCIB are made on the open market through the facilities of the TSX-V. For any common shares purchased, Hemisphere pays the prevailing market price of the common shares. The actual number of common shares that may be purchased for cancellation may not exceed 10% of the public float at the time of the NCIB renewal, and the timing of any such purchases will be determined by the Company and dependent on market conditions.

Hemisphere annually renewed its NCIB on July 14, 2021 under which the Company purchased, and subsequently canceled, 912,400 common shares. Hemisphere annually renewed its NCIB on July 14, 2022 under which the Company has purchased, and subsequently canceled, 2,022,300 common shares as of the date of this AIF.

SHARE CAPITAL

Common Shares

Hemisphere has an unlimited number of common shares authorized. As of the date of this AIF there are 101,776,639 common shares issued and outstanding. Holders of Hemisphere's common shares are entitled to notice of meetings and one vote per share at meetings of the Company's shareholders, to dividends if, as and when declared by the Board of Directors, and upon liquidation, dissolution or winding-up, to receive the Company's remaining property.

Stock Options

The Company has a stock option plan in place and is authorized to grant stock options to officers, directors, employees, and consultants whereby the aggregate number of shares reserved for issuance may not exceed 10% of the issued shares at the time of grant and 5% of the issued shares to each optionee. Stock options are non-transferable and have a maximum term of ten years. Stock options terminate no later than 90 days (30 days for investor-related services) upon termination of employment or employment contract and one year in the case of retirement, death, or disability. The grant price is determined using the closing price of the Company's shares from the day prior to the grant.

As of the date of this AIF the Company has 6,075,000 stock options outstanding of which 6,056,250 have vested and are exercisable.

Warrants

On April 15, 2022, the Company transacted a cashless exercise of the remaining 75% of the warrants at a $1.4367 30 day VWAP resulting in the issuance of 8,302,686 common shares for the exercise cost of 2,009,814 warrants at $0.28 per share. As of the date of this AIF, the Company has no warrants outstanding.

MARKET FOR SECURITIES

Common Share Trading

The outstanding common shares of the Company trade in Canada on the TSX-V under the symbol "HME" and in the United States on the OTCQX Venture Marketplace under the symbol "HMENF". The following table sets out the high and low price range and average trading volume of common shares as reported by the TSX-V, for the periods indicated.

	Price Range		
Trading Period	**High**	**Low**	**Total Volume Traded**
2022			
January	$1.10	$0.94	3,700,800
February	$1.41	$1.06	4,265,800
March	$1.67	$1.27	5,283,200
April	$1.65	$1.39	2,889,200
May	$1.73	$1.21	5,095,500
June	$1.98	$1.46	3,799,200
July	$1.62	$1.40	2,813,900
August	$1.72	$1.50	1,852,000
September	$1.63	$1.25	2,014,800
October	$1.60	$1.40	2,145,400
November	$1.60	$1.36	2,315,500
December	$1.45	$1.22	1,336,900
2023			
January	$1.40	$1.25	1,437,400
February	$1.38	$1.28	2,080,800
March	$1.47	$1.20	2,145,400
April 1 to 18	$1.34	$1.28	1,825,582

PRIOR SALES

The following table sets forth, for each class of securities of the Company that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the fiscal year ended December 31, 2022 and the number of securities of the class issued at that price and the date on which the securities were issued.

Date	Type of Securities	Number of Securities Outstanding	Exercise Price	Expiry Date
March 17, 2022	Stock Options	50,000	$1.41	March 17, 2032
May 10, 2022	Stock Options	150,000	$1.27	May 10, 2032
December 14, 2022	Stock options	3,150,000	$1.30	December 14, 2032

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

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

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with Hemisphere, the period served as a director and principal occupations of the Company's directors and officers are set out below:

Name and Municipality of Residence	Position with Hemisphere	Director or Officer Since	Principal Occupation During the Past Five Years
Don Simmons, P. Geol.(1) Vancouver, British Columbia, Canada	President and Chief Executive Officer Director	February 2008 May 2008	Previously Vice President Exploration of the Company from October 2007.
Charles O'Sullivan, B.Sc.(2) Vancouver, British Columbia, Canada	Chairman Director	2000 1978	Geophysicist and Mining Executive.
Frank Borowicz, QC, CA (Hon)(2)(3) Surrey, British Columbia, Canada	Director	July 2005	President of Pigasus Consulting Services Ltd., business consulting.

Name and Municipality of Residence	Position with Hemisphere	Director or Officer Since	Principal Occupation During the Past Five Years
Bruce McIntyre, P.Geol.(1)(3) Perth, Ontario, Canada	Director	July 2008	Most recently Executive Director of New Zealand Energy Corp. from July 2012 to June 2014 and previously President from April 2011 to July 2012.
Gregg Vernon, P. Eng.(2) Bogota, Cundinamarca, Colombia	Director	August 2006	Currently, President of Delaso Corporate Inc. Previously President of PMI Resources Ltd. from April 2017 to May 2018, Interim President and Chief Executive Officer of Petrodorado Energy Ltd. From October 2013 to February 2015. Prior thereto, Interim Chief Operating Officer of Petro Magdalena Energy Corp. (formerly Alange Energy Corp.) from January 2011 to its sale in July 2012.
Richard Wyman, B.Sc., MBA(1)(3) Calgary, Alberta, Canada	Director	October 2014	President of Chance Oil and Gas Limited (formerly Northern Cross (Yukon) Ltd.) since October 2010 and a director since 1994.
Ian Duncan, P. Eng. Vancouver, British Columbia, Canada	Chief Operating Officer	May 2011	Appointed Chief Operating Officer in September 2014. Previously Vice President, Engineering since May 2011 and an engineer with Hemisphere since January 2011.
Dorlyn Evancic, CPA, CGA Port Coquitlam, British Columbia, Canada	Chief Financial Officer	July 2007	Previously Chief Financial Officer of Northern Continental Resources Inc. from July 2007 to November 2009.
Andrew Arthur, P. Geol. Calgary, Alberta, Canada	Vice President, Exploration	July 2012	A consultant for Hemisphere from January 2012 to July 2012.
Ashley Ramsden-Wood, P.Eng. North Vancouver, British Columbia, Canada	Vice President, Engineering	September 2014	A consulting engineer for Hemisphere from June 2012 to September 2014. An engineer with NAL Resources from 2005 to 2011 and Petro Canada from 2002 to 2005.

Notes:

(1) Member of the Reserves Committee. Richard Wyman is the Chairman of the Reserves Committee.

(2) Member of the Compensation/Corporate Governance Committee. Charles O'Sullivan is Chairman of the Compensation/Corporate Governance Committee.

(3) Member of the Audit Committee. Bruce McIntyre is Chairman of the Audit Committee.

As at the date of this AIF, the directors, and officers of the Company, as a group, owned directly or indirectly 13,930,976 common shares or approximately 14% (17% on a fully diluted basis) of the issued and outstanding common shares.

The directors of the Company are elected annually and hold office until the next annual meeting of shareholders or until their successors are appointed.

Cease Trade Orders

Other than noted below, to the knowledge of the Company, no director or executive officer of the Company is, as at the date of this AIF, or was within 10 years before the date of this AIF, a director, chief executive officer or chief financial officer of any issuer (including the Company) that: (a) was subject to 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. For the purposes of the above, "order" means a 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 that was in effect for a period of more than 30 consecutive days.

Bankruptcies

To the knowledge of the Company, no director or executive officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company: (a) is, as at the date of this AIF, or has been within the 10 years before the date of this AIF, a director or executive officer of any issuer (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, become 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 10 years before the date of this AIF, 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.

Penalties or Sanctions

To the knowledge of the Company, no director or executive officer of the Company, or a shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, 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.

Conflicts of Interest

Directors and officers of the Company may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was subject of, during the last completed fiscal year, nor are any such legal proceedings known to the Company to be contemplated that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Company.

During the fiscal year ended December 31, 2022, there were: (i) no penalties or sanctions imposed against the Company or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and (iii) no settlement agreements the Company entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Company, any shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding common shares of the Company or any known associate or affiliate of such persons in any transactions within the three most recently completed fiscal years of the Company or during the current fiscal year which has materially affected, or would reasonably be expected to materially affect, the Company.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the common shares of the Company is Computershare Investor Services Inc. located at 3rd floor, 510 Burrard Street, Vancouver, British Columbia V6C 3B9.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Company during, or related to, the Company's most recently completed financial year other than McDaniel, the Company's independent engineering evaluators, and KPMG LLP, the Company's auditors. None of McDaniel or the "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of NI 51-102 of McDaniel have or are to receive any registered or beneficial interest, direct or indirect, in any of the Company's securities or other property of the Company or of the Company's associates or affiliates, at the time McDaniel prepared the report, valuation, statement or opinion. KPMG LLP, Chartered Professional Accountants, the Company's auditors, are independent within the meaning of the Chartered Professional Accountants of Alberta Rules of Professional Conduct.

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 the Company or of any associate or affiliate of the Company.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company has not entered into any material contracts within the most recently completed fiscal year or before the most recently completed fiscal year and which are still in effect, other than the Credit Facility, as outlined in *General Development of the Business – Three Year History of the Company*.

AUDIT COMMITTEE INFORMATION

Charter

The Company's Audit Committee is governed by an Audit Committee Charter, the text of which is attached as Appendix "C" of this AIF.

Composition

The Company's Audit Committee consists of three directors: Bruce McIntyre (Chairman), Frank Borowicz, and Richard Wyman. As defined in National Instrument 52-110 - *Audit Committees* ("NI 52-110"), Bruce McIntyre, Frank Borowicz, and Richard Wyman are "independent".

A member of the Audit Committee is "independent", if the member has no direct or indirect "material relationship" with the Company. A "material relationship" means a relationship which could, in the view of the Company's Board of Directors, reasonably interfere with the exercise of the member's independent judgment.

Relevant Education and Experience

NI 52-110 provides that a member of the Audit Committee is considered to be "financially literate" if he has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexities of the issues that can reasonably be expected to be raised by the Company's financial statements.

All of the members of the Company's Audit Committee are considered to be "financially literate", as that term is defined in NI 52-110.

Bruce McIntyre, P.Geol., Chairman

Mr. McIntyre has over 35 years of oil and gas experience and a proven track record of finding quality oil and gas reserves. Mr. McIntyre was most recently Executive Director of New Zealand Energy Corp. from July 2012 to June 2014 and prior to that, President from April 2011 to July 2012. Prior thereto, Mr. McIntyre was President and Chief Executive Officer of Sebring Energy Inc., a private Alberta-based exploration and production company that was sold in July 2007. He has also held various other management positions including President, CEO and co-founder of Sommer Energy Ltd., President and CEO of TriQuest Energy Corp., President and Chief Executive Officer of BXL Energy Ltd. and Exploration Manager for Gascan Resources Ltd. Mr. McIntyre is a member of the American Association of Petroleum Geologists, has a Professional Geologist designation with the Association of Professional Engineers and Geoscientists of Alberta and an Honorary Member of the Canadian Society of Petroleum Geologists (Past President 2002). Mr. McIntyre holds a Bachelor of Science Degree in Geology (Honours) from Carleton University and an Advanced Executive Certificate in General Management from Queen's University.

Frank Borowicz, QC, CPA, CA (Hon)

Mr. Borowicz has over 35 years of experience in corporate governance and regulatory compliance. He is a retired partner of the international law firm Davis LLP (now DLA Piper) and is a Governor of the Vancouver Board of Trade. He served as Chairman of the BC Industry Training Authority and is an independent director of several public and private companies. Educated at Harvard, Dalhousie and Loyola, Mr. Borowicz is a member of the Institute of Corporate Directors, is a Queen's Counsel, and an honorary Chartered Professional Accountant.

Richard Wyman, B.Sc., MBA

With over 35 years' experience, Mr. Wyman began his career as a reservoir engineer with Esso Resources Canada Ltd. in Calgary prior to becoming a corporate finance associate with Wood Gundy in London, England. He returned to Canada and became an analyst in the corporate finance and treasury department of Gulf Canada Limited in Calgary and Toronto, and then an oil and gas equities research analyst with Peters & Co. Limited. Following his tenure at Peters & Co. Limited, Mr. Wyman became a founding shareholder and Director of Smart Pipeline Services Ltd. and Northern Cross (Yukon) Ltd. He returned to a capital market role as Vice President and Senior Oil and Gas Analyst with Canaccord Genuity under its rebranding process in 2004. In 2010, Mr. Wyman returned to the oil and gas industry as President and a Director of Chance Oil and Gas Limited (formerly Northern Cross (Yukon) Ltd.), an emerging junior oil and gas, exploration and development company with assets located in Yukon. He holds a Bachelor of Applied Science degree in Chemical Engineering (Hons) from Queen's University in 1978 and a Masters of Business Administration from the International Management Institute at the University of Geneva in 1985.

Pre-Approval Policies and Procedures

The Company's Audit Committee reviews, and if determined advisable, pre-approves engagements for non-audit services to be provided by the external auditors or any of their affiliates, together with the estimated fees for such services. See also *Appendix C – Audit Committee Charter – External Auditors*.

External Auditor Service Fees

The Company's external auditor is KPMG LLP located at 3100–205 5th Avenue SW, Calgary, Alberta T2P 4B9.

The fees paid by the Company to its external auditor in each of the last two fiscal years are as follows:

Fiscal Year Ending	Audit Fees(1)	Audit Related Fees(2)	Tax Fees(3)	All Other Fees(4)
December 31, 2022	179,760	Nil	31,235	Nil
December 31, 2021	132,200	Nil	9,400	Nil

Notes:

(1) *"Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Company's financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation such as comfort letters, consents, reviews of securities filings and statutory audits.*

(2) *"Audit Related Fees" include services that are traditionally performed by the auditor. These audit related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews, consultations on conversion to International Financial Reporting Standards and audit or attest services not required by legislation or regulation.*

(3) *"Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice include assistance with tax audits and appeals, tax advice related to mergers and acquisitions and requests for rulings or technical advice from tax authorities.*

(4) *"All Other Fees" include all other non-audit services.*

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com or Hemisphere's website at www.hemisphereenergy.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans is contained in the Company's Information Circular for its most recent annual meeting of shareholders. Additional financial information is contained in the Company's audited annual financial statements and related Management's Discussion and Analysis for the year ended December 31, 2022.

Additional copies of this AIF, and any financial statements which have been issued by the Company, are available on the Company's website at www.hemisphereenergy.ca, upon request by mail at Suite 501, 1905 West Pender Street, Vancouver, British Columbia V6C 1L6, by email at info@hemisphereenergy.ca, by phone at (604) 685-9255, or by fax at (604) 685-9676.

APPENDIX "A"

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

February 15, 2023

Hemisphere Energy Corporation
501, 905 West Pender Street
Vancouver, British Columbia
V6C 1L6

Attention: The Board of Directors of Hemisphere Energy Corporation

Re: **Form 51-101F2**
Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor of Hemisphere Energy Corporation (the "Company")

To the Board of Directors of Hemisphere Energy Corporation (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022 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 + 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, 2022, 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	Net Present Value of Future Net Revenue M$ (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates	December 31, 2022	Canada	-	395,347.9	-	395,347.9

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

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

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

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(Signed) *"Michael J. Verney"*

Michael J. Verney, P.Eng.

Executive Vice President

Calgary, Alberta, Canada
February 15, 2023

APPENDIX "B"

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

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

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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

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

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

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

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

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

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

(c) the content and filing of this report.

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

(Signed) *"Don Simmons"*
Don Simmons
President & Chief Executive Officer

(Signed) *"Dorlyn Evancic"*
Dorlyn Evancic
Chief Financial Officer

(Signed) *" Richard Wyman"*
Richard Wyman
Director & Chairman of the Reserves Committee

(Signed) *"Bruce McIntyre "*
Bruce McIntyre
Director & Member of the Reserves Committee

April 19, 2023

APPENDIX "C"

AUDIT COMMITTEE CHARTER

Purpose

The Audit Committee of Hemisphere Energy Corporation ("Hemisphere") assists the Board of Directors in the oversight of its integrity in financial reporting as outlined in National Instrument 52-110 *Audit Committees* ("NI 52-110").

Composition

The Audit Committee consists of no less than three directors, each of whom is "financially literate" and "independent" as defined under NI 52-110, and is annually appointed by the Board of Directors. The Chair of the Audit Committee is appointed by the Board of Directors at the same time as the member appointment.

Mandate

- Assisting the Board of Directors in fulfilling their oversight responsibilities with respect to the review of financial statements and other relevant public disclosures, compliance with legal and regulatory requirements relating to financial reporting, the external auditors' qualifications and independence, and the performance of the internal audit function and the external auditors.

- Meeting quarterly to review and approve the quarterly financial statements and management's discussion and analysis for recommendation to the Board of Directors.

- Meeting annually to review and approve the audited annual financial statements and management's discussion and analysis for recommendation to the Board of Directors.

- Annually reviewing the performance of the external auditors.

- Nominating the external auditors for recommendation to the Hemisphere shareholders at the annual general meeting of the shareholders.

- Advising the Board of Directors on the remuneration of the external auditors based on the time required to complete the audit and preparation of the audited annual financial statements, and the difficulty of the audit and performance of the standard auditing procedures under generally accepted auditing standards and International Financial Reporting Standards.

External Auditors

Hemisphere's external auditors are the independent representatives of the shareholders, yet are also accountable to the Board of Directors and the Audit Committee. The external auditors complete their audit procedures and reviews with professional independence, free from any undue interference from management or directors. The Audit Committee directs and ensures that the management fully co-operates with the external auditors in the course of carrying out their professional duties. The Audit Committee will have access to direct communications with the external auditors, if required.

The external auditors are prohibited from providing any non-audit services to Hemisphere, without the written consent of the Audit Committee unless such non-audit services are *De Minimus* Non-Audit Services as outlined in section 2.4 of NI 52-110. In determining whether the external auditors will be granted permission to provide non-audit services, the Audit Committee is to consider that the benefits to Hemisphere from the provision of such services, outweighs the risk of any compromise to or loss of the independence of the external auditors in carrying out their auditing mandate.

Notwithstanding the above non-audit services, the external auditors are prohibited at all times from carrying out any of the following services, while they are appointed the external auditors of Hemisphere:

(a) acting as an agent of Hemisphere for the sale of all or substantially all of the undertaking of Hemisphere; and

(b) performing any non-audit consulting work for any director or senior officer of Hemisphere in their personal capacity, but not as a director, officer or insider of any other entity not associated or related to Hemisphere.

The Audit Committee has the power to terminate the services of the external auditors, with or without the approval of the Board of Directors, acting reasonably.

Internal Controls

The Board of Directors will appoint a person who is responsible for implementing internal controls and performing the role as the internal auditor ensuring such controls are adequate and effective.

Continuous Disclosure Requirements

The Board of Directors will appoint a person who is responsible for ensuring that Hemisphere's continuous reporting requirements are met and in compliance with applicable regulatory requirements.

Annual Review

The Corporate Governance Committee annually reviews the Audit Committee Charter and recommends any amendments to the Board of Directors for approval.