Hemisphere energy corporation

ANNUAL INFORMATION FORM

For the year ended December 31, 2019

April 23, 2020

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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, 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 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) per barrel of oil equivalent. 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 a key performance indicator and is by the Company in 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.

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 Suite 501, 905 West Pender Street, Vancouver, British Columbia V6C 1L6.

The Company does not have any subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History of the Company

Fiscal year ended December 31, 2017

In April 2017 Hemisphere closed a non-brokered private placement of 4,028,200 CDE flow-through common shares for gross proceeds of $1,133,496.

During the second quarter Hemisphere completed maintenance turnarounds at Jenner and Atlee, and added a pipeline to move water around to injectors better in Atlee.

In September 2017, Hemisphere entered into a first lien senior secured credit agreement with Cibolo Energy Partners, LP and certain of its affiliates (the "**Lender**") providing for a multi-draw, non-revolving term loan facility of a maximum aggregate principal amount of up to US$35.0 million (the "**Credit Facility**") with an initial commitment amount of US$15.0 million. The interest rate for the Credit Facility is the three-month United States dollar London Interbank Offered Rate ("**LIBOR**") with a LIBOR floor of 1%, plus 7.50% payable quarterly, for a five-year term with a maturity date of September 15, 2022. USD$15 million was drawn by the Company in order to repay the Former Credit Facility and complete significant capital activity in the Atlee Buffalo area, including drilling six development wells, building a G pool battery, expanding the existing F pool battery, and expanding its land base in the area.

Fiscal year ended December 31, 2018

On January 23, 2018, Hemisphere amended its credit agreement with its Lender in order to increase the commitment amount available on its Credit Facility by US$5.0 million, bringing the aggregate amount committed by the Lender to US$20.0 million. On June 1, 2018, Hemisphere amended its credit agreement with its Lender in order to increase the commitment amount available on its Credit Facility by an additional US$10.0 million, bringing the aggregate amount committed by the Lender to US$30.0 million.

Hemisphere drilled fourteen wells during 2018 at the Atlee Buffalo area, of which three were turned into injectors and eleven were placed on production. The Company also expanded both of its Atlee Buffalo batteries to handle increased production.

Fiscal year ended December 31, 2019

In 2019, Hemisphere drilled eleven development oil wells in the Atlee Buffalo area of southeast Alberta. All eleven wells were placed on production by the end of the fourth quarter.

The Company funded the drill program from cash flow, and drew an additional US$0.5 million from its term loan during the year for working capital.

On June 27, 2019, Hemisphere announced that the TSX Venture Exchange ("**TSX-V**") had accepted the Company's notice of intention to commence a normal course issuer bid to purchase up to 8,016,731 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 normal course issuer bid commenced on July 1, 2019 and expires on July 1, 2020. 1,301,000 common shares of the Company have been purchased under the normal course issuer bid.

Significant Acquisitions

The Company did not make any significant acquisitions during 2019.

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".

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, 2019, Hemisphere had seven full-time head office employees and one full-time field employee. Additionally, the Company had six part-time consultants and three 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 operation 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.

Public Health Crises

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as the current COVID-19, may adversely affect the Company

The Company's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China. On January 30, 2020, the World Health Organization declared the outbreak a global health emergency and on March 11, 2020, the World Health Organization declared the outbreak a pandemic. Reactions across the globe to the spread of COVID-19 have led to, among other things, significant restrictions on travel, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread from China throughout Europe, the Middle East, Canada and the United States, amongst other countries, causing cities, provinces, states, countries and specific companies to impose unprecedented restrictions such as quarantines, business closures, shelter in place declarations and travel restrictions, amongst other measures in an attempt to slow the spread of COVID-19. While these effects are expected to be temporary, the duration of the business disruptions domestically and internationally and related financial impact cannot be reasonably estimated at this time and may last for an extended period of time. Similarly, the Company cannot estimate whether or to what extent this outbreak and the potential financial impact may extend to countries outside of those currently most heavily impacted. Such public health crises can result in volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, oil prices have significantly weakened in response to the outbreak of COVID-19. See "– *Weakness and Volatility in the Oil and Natural Gas Industry*". The risks to the Company of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations impacted by an outbreak. At this point, the extent to which COVID-19 may impact the Company is uncertain; however, it is possible that COVID-19 may have a material adverse effect on the Company's business, results of operations and financial condition.

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, may adversely affect the Company by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs (as defined herein) and natural gas, (ii) impairing its supply chain (for example, by limiting the manufacturing of materials or the supply of services used in the Company's operations), and (iii) affecting the health of its workforce, rendering employees unable to work or travel.

Should an employee or visitor in any of the Company's facilities, offices or work sites become infected with a serious illness that has the potential to spread rapidly, this could place the Company's workforce at risk. The 2020 outbreak of COVID-19 is one example of such an illness. The Company takes every precaution to strictly follow industrial hygiene and occupational health guidelines. Additionally, the Company follows posted health guidelines, as and when posted, to protect the health of its employees and decrease the potential impact of serious illness on its operations. There can be no assurance that this virus or another infectious illness will not impact the Company's personnel and ultimately its operations.

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

Natural Disasters, Terrorist Acts, Civil Unrest, Pandemics and Other Disruptions and Dislocations, such as the recent COVID-19 (coronavirus), may adversely affect the Company

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, state or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Company, 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 COVID-19 pandemic, domestic and global trade disruptions, infrastructure disruptions, civil disobedience or unrest (including the most recent protests and railway blockades in Canada), natural disasters, national emergencies, acts of war, technological attacks and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company, its customers, and/or either of their businesses or operations, which may have a material adverse effect on the Company's reputation, business, financial conditions or operating results.

Weakness in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and natural gas industry may affect the value of the Company's reserves and restrict its cash flow and ability to access capital to fund the development of it properties

Market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries, including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Risk Factors – Political Uncertainty*". These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Risk Factors – Royalties and Incentives*", " *Risk Factors – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors – Climate Change Regulation*". In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of the Company's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Company's cash flow resulting in less funds from operations being available to fund the Company's capital expenditure budget. Consequently, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year-over-year basis. See "*Risk Factors – Reserves Estimates*". In addition to possibly resulting in a decrease in the value of the Company's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Company's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Company's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. See "*Risk Factors – Additional Funding Requirements*".

Exploration, Development and Production Risks

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

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

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected competitiveness of other jurisdictions, including Canada. In addition, the North American Free Trade Agreement ("**NAFTA**") has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the Canada–United States–Mexico Agreement which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. The Canadian Parliament has not yet passed legislation to implement the USMCA. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Company.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Company's ability to market its products internationally, increase costs for goods and services required for the Company's operations, reduce access to skilled labour and negatively impact the Company's business, operations, financial conditions and the market value of the its common shares.

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. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project while a minority government in British Columbia remains opposed to the project and has attempted to regulate the transport of heavy oil products into and through British Columbia. Though the Supreme Court of Canada unanimously rejected the government of British Columbia proposed regulation of the transport of heavy oil products into and through British Columbia, disputes remain between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction.

The federal government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Political instability, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

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 affect on the Company's financial and operational results. See "*Industry Conditions – Liability Management Rating Program*" and "*Risk Factors – Third Party Credit Risk*".

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*" and "*Industry Conditions – Curtailment*". 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 shut downs 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. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. 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.

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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*", "*Industry Conditions – Curtailment*" and "*Risk Factors – Liability Management*".

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 Rating Programs*".

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*".

Hydraulic Fracturing

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

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

Alberta

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

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 – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change 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.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Company's operating expenses and may impair the Company's ability to compete

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Company's ability to acquire properties or require a substantial cash deposit with the regulator

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the Liability Management Rating Program (the "**AB LMR Program**") administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to the Company's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in *Redwater Energy Corporation* (Re) ("**Redwater**") on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program regime may prevent or interfere with the Company's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and natural gas companies that may be disproportionately affected by price instability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Climate change may pose varied and far ranging risks to the business and operations of the Company, both known and unknown, that may adversely affect the Company's business, financial condition, results of operations, prospects, reputation and share price

Chronic Climate Change Risks

The Company's exploration and production facilities and other operations and activities emit greenhouse gases ("**GHG**") which may require the Company to comply with greenhouse gas emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change and or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of the Company's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

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

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels, which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term reducing the demand for oil and natural gas production, resulting in a decrease in the Company's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk Associated with the Company's Operations*" and "*Risk Factors – Changing Investor Sentiment*".

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Company's ability to access its properties, cause operational difficulties including damage to machinery and facilities. 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 farmland and wild grassfires may lead to significant downtime and/or damage to such assets. Moreover, extreme weather conditions may lead to disruptions in the Company's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

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.

See "*Industry Conditions – Royalties and Incentives*".

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 is required to comply with positive and negative covenants under its Credit Facility which in certain cases, include certain operational and financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding and in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. 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 Credit Facility, 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 Credit Facility may impose 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 Lenders use the Company's reserves, existing and forecast commodity prices, applicable discount rate and other factors to periodically determine the Company's compliance with certain of its covenants under its Credit Facility. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices have recently increased they remain volatile as a result of various factors including limited egress options for Western Canadian oil and natural gas producers, actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce the funds available to the Company under the Credit Facility. This could result in the requirement to repay a portion, or all, of the Company's indebtedness.

The Supreme Court of Canada's decision in Redwater may give rise to new covenants and restrictions under the Credit Facility, should liability management rating ("**LMR**") levels fall below existing agreed-upon thresholds, including further limitations on asset dispositions and acquisitions. The Company may also be required to provide additional reporting to its lenders regarding its existing and/or budgeted abandonment and reclamation obligations, its decommissioning expenses, its LMR and/or any notices or orders received from an energy regulator in any applicable province.

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 counter-party 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.

Availability and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede the Company's exploration, development and operating activities

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Company's exploration, development and operating activities.

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 and Eco-Terrorism Risks

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 does not pay dividends and there is no assurance that it will do so in the future.

The Company has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, cash flow, results of operations, financial condition of the Company, the need for funds to finance ongoing operations and other considerations, as the Board of Directors of the Company considers relevant.

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 affect on the Company's financial condition.

Indigenous Claims

Indigenous claims may affect the Company

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. The Company is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays in the construction of infrastructure systems and facilities which could have a material adverse effect on the Company's business and financial results.

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.

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 has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The 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 normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company’s information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to 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 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 carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations do not affect the Company's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although laws and regulations are a matter of public record, the Company is unable to predict what additional laws, regulations 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 deriving authority from underlying 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; (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; (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 certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil, including global events such as the outbreak of COVID-19. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale. Worldwide oversupply of crude oil, a lack of available storage capacity and dramatically decreased demand due to the COVID-19 pandemic have driven crude oil prices to historic lows in 2020. OPEC and other oil producing countries announced an agreement to cut production by approximately 10 million bbls/d on April 12, 2020, in an effort to stabilize global oil markets.

Natural Gas

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

Natural Gas Liquids

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. 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.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Export crude oil, natural gas and NGLs from Canada are subject to CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's a written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("**Cabinet**") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, 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 not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different areas and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due 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.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from 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 require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets, through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience difficulties and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's Indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to of the Federal Court of Appeal decision, quashing the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and continues with modifications in place to allow for physical distancing on work sites. Construction is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two Indigenous groups subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019. The Federation of British Columbia Naturalists, an environmental group that was denied standing in the December 2019 judicial review, appealed the Federal Court of Appeal's standing decision to the Supreme Court of Canada. The appeal was dismissed on March 5, 2020.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

While it was expected that construction on the Keystone XL Pipeline ("**KXL**"), owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, the project has been subject to a number of delays. However, 2020 has seen progress for TC Energy. In January 2020, the United States government announced its approval of a key right-of-way that would allow KXL to cross 74 kilometers of federal land. On March 31, 2020, TC Energy announced a final investment decision to proceed with KXL, which included the announcement of a US $1.1 billion equity investment by the Government of Alberta in KXL, and that the Government of Alberta would fully guarantee a US $4.2-billion project-level credit facility.

TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and the first segment of KXL in the United States was installed in April 2020. Nevertheless, KXL remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits, and on April 15, 2020 a Montana judge ruled against the U.S. Army Corps of Engineers' use of a national permit that allows new energy pipelines throughout the country to cross water bodies. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations. The COVID-19 pandemic has given rise to further opposition to continued construction and concern about the ability of workers to build the pipeline while maintaining physical distancing and environmental standards. An application to halt production was brought before a United States Federal Judge on April 16, 2020.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the Oil Tanker Moratorium Act, which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tones to or from British Columbia's north coast. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents. On February 11, 2020, the Government of Alberta announced that it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2020, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits from February 6, 2020 to April 1, 2020, following two derailments that led to fires and oil spills in Saskatchewan.

Natural Gas

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project, which will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, BC, via the Coastal GasLink pipeline, which will be built and operated by TC Energy's subsidiary Coastal GasLink ("**CGL**") (the "**CGL Pipeline**"). Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell 65% of its interest in the CGL Pipeline, to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction is expected to close in the first half of 2020. The CGL Pipeline's route was altered as a result of feedback that LNG Canada received from Indigenous groups in the area, and on May 1, 2019, the British Columbia Oil and Gas Commission (the "**BC Commission**") approved the current planned route for the CGL Pipeline. However, the CGL Pipeline has faced intense opposition. For example, a challenge to the approval process of the CGL Pipeline was launched in August 2018, contending that it should have been subject to the federal review instead of a provincial review. In July 2019, the NEB confirmed that the CGL Pipeline was properly subject to provincial jurisdiction. In addition, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays of construction activities on the CGL Pipeline. Coastal Gaslink Pipeline Ltd. obtained an injunction on December 31, 2019, and enforcement of the injunction started in February 2020.

On February 19, 2020, the British Columbia Environmental Assessment Office (the "**EAO**") directed CGL to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being revised and finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Impact Assessment Agency of Canada ("**IA Agency**") has extended the timeline for the planning phase until July 18, 2020 at the request of the Province of Quebec. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, but Pieridae Energy Ltd. has delayed a final investment decision until the fourth quarter of 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the IA Agency.

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, as amended effective October 1 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbls/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for April 2020 and May 2020 is set at 3.81 million bbls/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta. The Curtailment Rules are set to be repealed by December 31, 2020.

The Company is not currently subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/USMCA

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Since coming into force, NAFTA has governed trade relations among its member countries. However, on November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "CUSMA".

As of March 13, 2020, each of Canada, the United States and Mexico have ratified the USMCA and it will come into force on June 1, 2020. Until then, NAFTA will continue to govern trade relations among Canada, Mexico, and the United States. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Article 605 of NAFTA (the proportionality clause) has historically prevented Canada from reducing oil and gas exports to the United States and Mexico relative to the total supply produced in Canada. Despite reducing crude oil production, the Government of Alberta's curtailment program has been compliant with NAFTA due to the operation of the proportionality rule. Reducing Canadian supply reduced Canada's required offering, thereby allowing Alberta to reduce production without causing Canada to breach its export obligations. However, the USMCA does not contain the proportionality rules of Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by 14 of 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and ten other countries have agreed on the text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam and Singapore.

While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the crude oil 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

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

On March 20, 2020, the Government of Alberta announced that all Crown Petroleum and Natural Gas agreements, Oil Sands agreements, and Metallic and Industrial Mineral permits expiring from March 20, 2020 up to and including December 31, 2020 will be extended for one year, in response to the economic stress on Alberta's oil and natural gas producers caused by the COVID-19 pandemic. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences. British Columbia has a policy of "zone specific retention" that 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 crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

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

Until recently, oil and natural gas activities conducted on Indigenous reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed An Act to Amend the Indian Oil and Gas Act, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. The Company has/does not have operations on Indigenous reserve lands.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable typically depends in part on prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totaling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells 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.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the AER on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

Oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly, and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014, and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

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

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

British Columbia

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGLs in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGLs and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGLs and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will, therefore, vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare, depending on the total number of hectares owned by the entity.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

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

Regulatory Authorities and Environmental Regulation

General

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

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On August 28, 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* ("**IAA**") came into force and the NEB Act and the *Canadian Environmental Assessment Act, 2012* ("**CEAA 2012**") were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

"Designated projects" under the IAA include interprovincial or international pipelines that require more than 75km of new right of way, and will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The impact assessment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75km of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

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. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested. The Government of Alberta is challenging the constitutionality of Bill C-69, and has submitted a reference question to the Alberta Court of Appeal. The case is expected to be heard in the fall of 2020.

On May 12, 2017, the federal government introduced Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the *Oil Tanker Moratorium Act* which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53′00′′ north latitude and west of 126°38′36′′ west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

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 legislation including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

On March 20, 2020, the Government of Alberta announced a $113 million contribution to the AER's industry levy, intended to provide financial relief in response to the economic stress and uncertainty facing Alberta's oil and natural gas industry as a result of the COVID-19 pandemic. On April 9, 2020, the Government of Alberta announced that Alberta Energy is deferring all public land sales and direct purchases of petroleum and natural gas and oil sands mineral rights for a minimum of 90 days, in response to the COVID-19 pandemic. The AER has suspended reporting requirements under the *Coal Conservation Act*, the OGCA, and the OSCA until August 14, 2020, and Alberta Environment and Parks has suspended most reporting requirements relating to approvals or registrations in the EPEA, licenses and approvals in the *Water Act*, and formal dispositions in the *Public Lands Act*. However, the obligation to monitor and collect data normally reported within any such approvals remains in place and subject to enforcement, as does the obligation to report emergencies, contraventions, releases and other incidents. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

The Government of Alberta relies on regional planning to accomplish its responsible 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 by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. 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 for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented. These regional plans may affect further development and operations in such regions.

Liability Management

On April 17, 2020, as part of an announcement of federal relief for Canada's oil and natural gas industry in response to the COVID-19 pandemic, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. The federal government also announced that it aims to address the oil and natural gas industry's concerns over liquidity by working with the Business Development Bank of Canada and Export Development Canada to strengthen credit support for medium-sized oil and natural gas companies. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

Alberta

The AER administers the AB LMR Program. The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licenses. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's LMR. Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect the Company's ability to obtain or transfer licenses.

Complementing 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 AB OWL Program, including the Company, fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. 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. On April 12, 2020 the Government of Alberta passed Bill 12: *The Liabilities Management Statutes Amendment Act*, which enables the Orphan Fund to manage and accelerate the clean-up of wells or sites which do not have a responsible owner. Bill 12 will come into force on proclamation.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions, holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, 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 transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs pending a final decision from the Supreme Court of Canada. The AER amended its licensing and liability management programs. Over the course of Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licencee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

In early March 2020, the Government of Alberta announced an extension of an existing $235 million loan to the Orphan Fund by up to $100 million, earmarked for decommissioning approximately 1,000 wells and initiating reclamation on 1,000 sites.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP completed its fifth year on March 31, 2020 but the AER has not released its subsequent annual reports on compliance levels since 2017. On April 9, 2020 the AER suspended the compliance deadline for the final year of the IWCP under Directive 013 for inactive wells under the IWCP, in response to the COVID-19 pandemic.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets. The Company is not participating in the voluntary ABC program.

British Columbia

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

As a result of certain amendments to the OGAA, on April 1, 2019 a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The OGAA permits the B.C. Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the B.C. Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in an annual work plan.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada.

The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments 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. As of December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2018, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. 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 emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

Seven provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, the Northwest Territories and Newfoundland. The federal fuel charge regime took effect in Saskatchewan, Manitoba and Ontario on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal fuel charge regime took effect in Alberta on January 1, 2020. While New Brunswick was previously subject to the federal fuel charge, the federal government agreed to recognize the equivalency of New Brunswick's proposed fuel charge in December 2019. The New Brunswick fuel charge will take effect on April 1, 2020.

Alberta, Saskatchewan and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada. The Court was set to hear the appeals in March 2020, but they have been tentatively postponed until June 2020 due to the COVID-19 pandemic. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia, along with various other interested parties.

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 crude 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 intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

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

On April 17, 2020, as part of its efforts to provide relief to Canada's oil and natural gas industry in light of the COVID-19 pandemic, the federal government announced a $750 million allocation to an Emissions Reduction Fund intended to create and maintain jobs through pollution reduction initiatives, with a focus on reduction of methane emissions. Funds disbursed through this program will primarily take the form of repayable contributions to conventional and offshore oil and gas firms.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the Oil Sands Emissions Limit Act came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed Technology Innovation and Emissions Reduction ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

On March 30, 2020, the Government of Alberta extended the deadlines to submit compliance reports and emissions reduction plans from March 31, 2020 to June 30, 2020.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the *Alberta Methane Regulations*; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the *Alberta Methane Regulations* and the *Federal Methane Regulations*.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, the Government raised the carbon tax to $35/tonne in April 2018, and subsequently raised it to $40/tonne on April 1, 2019. The Government of British Columbia intends to continue raising its carbon tax in $5 increments until it reaches $50/tonne in 2021.

On January 1, 2016, the *Greenhouse Gas Industrial Reporting and Control Act* (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, "**CleanBC**", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: i) increasing the generation of electricity from clean and renewable energy sources; ii) imposing a 15% renewable content requirement in natural gas by 2030; iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; iv) investing in the electrification of crude oil and natural gas production; v) reducing 45% of methane emissions associated with natural gas production; and vi) incentivizing the adoption of zero-emissions vehicles. The 2019 provincial budget provided $902 million over three years to support CleanBC, including electric vehicle rebates, incentives for making homes and businesses more energy efficient, and an enhanced climate action tax credit. On January 16, 2019, the B.C. Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020.

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 March 25, 2020 with an effective date of December 31, 2019 (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.

The reserves of the Company and the estimated net present value of the future net revenue of the Company's reserves set forth in the tables above reflect the royalty regime in place for the Province of Alberta as of the effective date of the McDaniel Report being December 31, 2019 and reflect the Modernized Royalty Framework released by the Government of Alberta on January 29, 2016. See "*Industry Conditions – Royalties and Incentives – Alberta*".

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, 2019
Forecast Prices and Costs
Reserves Summary

	Heavy Crude Oil		**Conventional Natural Gas**	
Reserves Category	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (MMcf)	Net[(2)] (MMcf)
Proved				
Developed Producing	4,780.5	4,046.9	938.9	860.0
Developed Non-Producing	63.6	57.9	13.1	11.1
Undeveloped	4,871.1	4,169.8	227.5	207.6
Total Proved	**9,715.2**	**8,274.7**	**1,179.4**	**1,078.8**
Total Probable	2,233.2	1,828.8	304.3	277.3
Total Proved Plus Probable	**11,948.4**	**10,103.5**	**1,483.8**	**1,356.1**

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	161,808.1	136,442.2	115,712.1	100,014.4	88,072.0	27.61
Developed Non-Producing	355.4	306.2	265.4	231.1	202.2	4.44
Undeveloped	155,541.0	111,314.7	82,219.0	62,368.7	48,376.5	19.56
Total Proved	**317,704.5**	**248,063.0**	**198,196.5**	**162,614.2**	**136,650.8**	**23.44**
Probable	89,303.5	54,946.4	36,316.7	25,474.2	18,752.8	19.37
Total Proved Plus Probable	**407,008.0**	**303,009.5**	**234,513.2**	**188,088.4**	**155,403.5**	**22.70**

Note:

(1) The unit values are based on net 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	137,634.0	118,345.1	101,710.1	88,883.0	79,022.3
Developed Non-Producing	270.8	227.7	192.7	163.9	139.9
Undeveloped	119,283.4	84,920.6	62,268.7	46,818.4	35,945.1
Total Proved	**257,188.2**	**203,493.3**	**164,171.4**	**135,865.3**	**115,107.2**
Probable	69,141.0	42,436.0	27,986.8	19,593.6	14,399.0
Total Proved Plus Probable	**326,329.1**	**245,929.3**	**192,158.2**	**155,458.9**	**129,506.2**

Total Future Net Revenue
(Undiscounted)
As of December 31, 2019
Forecast Prices and Costs

Reserves Category	Revenue[(1)]	Royalties[(2)]	Operating Costs	Development Costs	Abandon-ment & Reclamation Costs[(3)]	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	M$	M$	M$	M$	M$	M$	M$	M$
Total Proved	627,441	91,628	164,564	37,722	15,823	317,705	60,516	257,188
Total Proved plus Probable	790,907	120,130	208,987	38,752	16,031	407,008	80,679	326,329

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 Corporation. See "Abandonment and Reclamation Costs" below.*

Future Net Revenue by Product Type
As of December 31, 2019
Forecast Prices and Costs

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%) M$	Unit Value[1] $/bbl	$/Mcf
Proved	Heavy Crude Oil (including solution gas and by-products)	198,196	23.95	
Proved Plus Probable	Heavy Crude Oil (including solution gas and by-products)	234,513	23.21	

Notes:

(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, 2020 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, 2020

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)
2020	61.00	72.64	57.57	2.04	0	0.76
2021	63.75	76.06	62.35	2.32	1.7	0.77
2022	66.18	78.35	64.33	2.62	2.0	0.785
2023	67.91	80.71	66.23	2.71	2.0	0.785
2024	69.48	82.64	67.97	2.81	2.0	0.785
2025	71.07	84.60	69.72	2.89	2.0	0.785
2026	72.68	86.57	71.49	2.96	2.0	0.785
2027	74.24	88.49	73.20	3.03	2.0	0.785
2028	75.73	90.31	74.80	3.09	2.0	0.785
2029	77.24	92.17	76.43	3.16	2.0	0.785
2030	78.79	94.01	77.96	3.23	2.0	0.785
2031	80.36	95.89	79.52	3.29	2.0	0.785
2032	81.97	97.81	81.11	3.36	2.0	0.785
2033	83.61	99.76	82.73	3.43	2.0	0.785
2034	85.28	101.76	84.39	3.49	2.0	0.785
Thereafter		Escalation Rate of 2%/year			2.0	0.785

The weighted average sales prices realized by Hemisphere for the year ended December 31, 2019 were $53.30/bbl for heavy crude oil, $42.05/bbl for NGLs and $1.87/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, 2018	**7,454.4**	**2,953.0**	**10,407.4**	**946.1**	**309.1**	**1,255.2**	**-**	**-**	**-**	**7,612.1**	**3,004.5**	**10,616.6**
Extensions and improved recovery	1365.0	-865.1	499.9	25.3	6.2	31.5	-	-	-	1,369.2	-864.1	505.1
Infill Drilling	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions[1]	1,476.5	145.4	1,621.9	335.5	-11.0	324.5	0.5	-	0.5	1,533.0	143.5	1,676.5
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	v	-	-	-	-	-	-
Production	580.7	-	580.7	127.4	-	127.4	0.5	-	0.5	602.5	-	602.5
Dec. 31, 2019	**9,715.2**	**2233.2**	**11,948.4**	**1,179.4**	**304.4**	**1,483.8**	**-**	**-**	**-**	**9,911.8**	**2,283.9**	**12,195.7**

Notes:

(1) Negative technical revisions for heavy oil in the Probable Category are due to the conversion of such reserves into the Proved Category as a result of drilling success.

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, 2019, 2018, and 2017 based on forecast prices and costs.

	Heavy Crude Oil		**Conventional Natural Gas**	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End

	Gross (Mbbl)	Gross (Mbbl)	Gross (MMcf)	Gross (MMcf)
Proved Undeveloped				
December 31, 2017	1,176.9	2,665.6	50.5	151.6
December 31, 2018	2,796.2	4,049.4	123.6	183.8
December 31, 2019	1,365.0	4,871.1	25.3	227.5
Probable Undeveloped				
December 31, 2017	622.7	1,451.1	16.9	48.1
December 31, 2018	983.8	1,915.4	30.4	45.6
December 31, 2019	-865.1	1,060.4	6.2	55.7

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 four 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 four 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, 2019, Hemisphere had 122.2 net wells for which abandonment and reclamation costs are expected to be incurred over the next forty-seven 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) $16.0 million (undiscounted) and $2.2 million (10% discount) for abandonment and reclamation costs in the proved plus probable reserves category; and (ii) $15.8 million (undiscounted) and $2.2 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 Alberta Energy Regulator 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, 2019 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$

2020	6,420	6,420
2021	8,786	8,786
2022	12,700	12,700
2023	9,816	10,845
Remaining	-	-
Total (Undiscounted)	**37,722**	**38,752**

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.

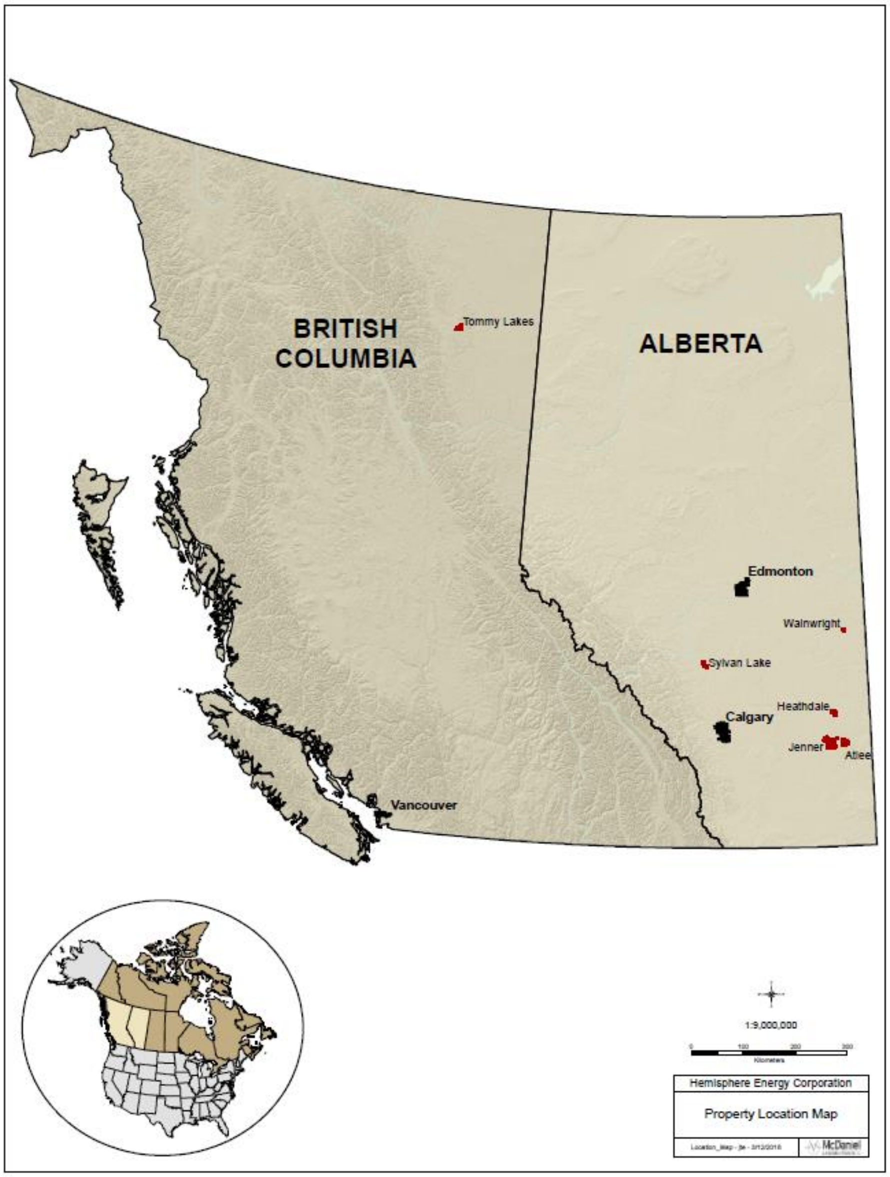
"undeveloped reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, 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, 2019 are located in Alberta and British Columbia. The following map identifies the location of the Company's assets:



Core Assets

The Company has two producing core assets located in southeast Alberta.

Jenner

Jenner is located 100 kilometres northwest of Medicine Hat. Hemisphere first entered the area in 2010 and owns 8,200 gross acres (7,224 net acres) as of December 31, 2019. 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, 2019, the McDaniel Report assigned total proved plus probable reserves of 1,067.4 Mbbl of heavy crude oil and 424.4 MMcf of conventional natural gas to the Company's Jenner property area. The Company held an interest in 3,960 gross acres 3,624 net acres) of undeveloped land in the Jenner area as of December 31, 2019.

Atlee Buffalo

Atlee Buffalo is located 25 kilometres northeast of Jenner. Hemisphere made its first acquisition in the area in late 2013 and owns 9,760 gross acres (9,760 net acres) as of December 31, 2019. The property has two oil pools delineated by vertical wells and defined by 3D seismic.

At December 31, 2019, the McDaniel Report assigned total proved plus probable reserves of 10,881.0 Mbbl of heavy crude oil and 1,059.4 MMcf of conventional natural gas to the Company's Atlee Buffalo property area. The Company held an interest in 6,800 gross acres (6,800 net acres) of undeveloped land in the Atlee Buffalo area as of December 31, 2019.

Non-Core Assets

Trutch (Tommy Lakes) is located 250 kilometres northwest of Fort St. John, British Columbia. The Company owns 5,456 gross acres (1,909 net acres) as of December 31, 2019, which includes non-operated wells producing liquids rich natural gas. At December 31, 2019, the McDaniel Report assigned no economic reserves for this property. The Company held an interest in 2,046 gross acres (613 net acres) of undeveloped land in the Trutch area as of December 31, 2019.

Hemisphere also has various working interests in three other non-core assets located in southern Alberta (Sylvan Lake, Heathdale, and Wainwright). At December 31, 2019, the McDaniel Report assigned no economic reserves for these properties. The Company held an interest in 3,360 gross acres (888 net acres) of land, of which 640 gross acres (160 net acres) are undeveloped in its non-core asset property areas as of December 31, 2019.

Oil and Natural Gas Wells

The following table summarizes Hemisphere's interest as at December 31, 2019 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	32	32	-	-	7	7	2	2
Jenner	8	8	-	-	21	21	4	4
Heathdale	-	-	-	-	-	-	-	-
Sylvan Lake	-	-	-	-	-	-	10	2.8
Wainwright	-	-	-	-	-	-	1	0.69
British Columbia								
Trutch	-	-	-	-	-	-	1	0.5
Total	**31**	**31**	**5**	**1.55**	**27**	**27**	**17**	**9.84**

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 less than 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 of 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, 2019:

	Exploratory Wells		**Development Wells**	
	Gross	Net	Gross	Net
Oil	-	-	11	11
Gas	-	-	-	-
Water Injector	-	-	-	-
Service Well	-	-	-	-
Stratigraphic Test Well	-	-	-	-
Dry Hole	-	-	-	-
Total	**-**	**-**	**11**	**11**

Production History

	Three Months Ended				Year Ended
	Mar. 31, 2019	Jun. 30, 2019	Sept. 30, 2019	Dec. 31, 2019	Dec. 31, 2019
Average daily production					
Heavy crude oil (bbl/d)	1,329	1,317	1,670	2,101	1,607
Conventional natural gas (Mcf/d)	287	295	404	381	342
NGL (bbl/d)	2	1	1	2	1
Combined (boe/d)	1,379	1,367	1,738	2,166	1,665
Average sales prices					
Heavy crude oil ($/bbl)	52.18	62.15	53.21	48.57	53.30
Conventional natural gas ($/Mcf)	7.14	(2.14)[(3)]	0.80	2.21	1.87
NGL ($/bbl)	43.84	32.29	55.62	38.64	42.05
Combined ($/boe)	51.85	59.44	51.34	47.53	51.85
Operating netback ($/boe)					

Petroleum and natural gas Revenue	51.85	59.44	51.34	47.53	51.85
Royalties	5.30	8.99	6.95	4.97	6.38
Operating costs	9.65	12.84	9.37	8.36	9.81
Transportation costs	2.45	2.59	2.45	2.67	2.55
Operating field netback(1)	34.45	35.02	32.57	31.53	33.11
Realized commodity hedging gain (loss)	(3.56)	(3.92)	(1.93)	(0.83)	(2.31)
Operating netback(2)	30.89	31.10	30.64	30.70	30.80

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.*
(3) *This price decrease is due to an overpayment on the Company's non-operated joint interest in British Columbia in March 2019, which was subsequently reversed in April 2019.*

Production Estimates

The following table discloses, by product type, the total volume of production estimated by McDaniel for the year ending December 31, 2020 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	1,995	202	2,028
Heathdale	-	-	-
Jenner	165	132	187
Sylvan Lake	-	-	-
Wainwright	-	-	-
British Columbia			
Trutch	-	-	-
Total	**2,160**	**334**	**2215**

Proved Plus Probable	Heavy Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Total (boe/d)
Alberta			
Atlee Buffalo	1,996	202	2,030
Heathdale	-	-	-
Jenner	168	134	190
Sylvan Lake	-	-	-
Wainwright	-	-	-
British Columbia			
Trutch	-	-	-
Total	**2,164**	**336**	**2,220**

Land Holdings Including Properties with No Attributed Reserves

The following table summarizes, by province, Hemisphere's developed and undeveloped landholdings as at December 31, 2019:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	**Gross**	**Net**
Alberta						
Atlee Buffalo	2,960	2,960	6,800	6,800	**9,760**	**9,760**
Heathdale	160	-	640	160	**800**	**160**
Jenner	4,240	3,600	3,960	3,624	**8,200**	**7,224**
Sylvan Lake	1,920	288	-	-	**1,920**	**288**
Wainwright	640	440	-	-	**640**	**440**
British Columbia						
Trutch	3,410	1,296	2,046	613	**5,456**	**1,909**
Total	**13,330**	**8,584**	**13,446**	**11,197**	**26,776**	**19,781**

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 2020, if not continued:

Location	Acreage	
	Gross	Net
Atlee Buffalo	1,600	1,600
Jenner	1,280	1,280
Trutch	-	-
Heathdale	-	-

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, 2019, Hemisphere has the following commodity contracts in place:

Product	Type	Volume	Price	Index	Term	Dec. 31, 2019 Fair Value
Crude oil	Swap	425 bbl/d	US$58.40	WTI-NYMEX	January 1, 2020 – March 31, 2020	(111,747)
Crude oil	Swap	425 bbl/d	US$57.15	WTI-NYMEX	April 1, 2020 – June 30, 2020	(105,497)
Crude oil	Swap	200 bbl/d	US$50.67	WTI-NYMEX	January 1, 2020 – August 31, 2020	(553,959)
Crude oil	Swap	425 bbl/d	US$55.85	WTI-NYMEX	July 1, 2020 – September 30, 2020	(90,617)
Crude oil	Collar	120 bbl/d	US$40.00-US$68.25	WTI-NYMEX	January 1, 2020 – December 31, 2020	(21,992)
Crude oil	Collar	200 bbl/d	US$40.00-US$67.05	WTI-NYMEX	September 1, 2020 – December 31, 2020	(19,009)
Crude oil	Swap	425 bbl/d	US$54.85	WTI-NYMEX	October 1, 2020 – December 31, 2020	(74,722)
Crued oil	Collar	275 bbl/d	US$40.00-US$65.50	WTI-NYMEX	January 1, 2021 – March 31, 2021	(18,999)
Crude oil	3-Way	350 bbl/d	US$40.00(put)/US$48.60 (put)/US$60(call)	WTI-NYMEX	January 1, 2021 – March 31, 2021	(51,971)
Crude oil	3-Way	625 bbl/d	US$40.00(put)/US$48.00 (put)/US$60(call)	WTI-NYMEX	April 1, 2021 – June 31, 2021	(81,030)
					Total	(1,129,543)

Hemisphere was not required to pay income taxes during the year ended December 31, 2019 and has approximately $67 million of tax pools available to be applied against future income for tax purposes. Based on available pools and current commodity prices, the Company does not expect to pay income tax in 2019 or 2020. Taxes payable beyond 2020 will primarily be a function of commodity prices, capital expenditures, and production volumes.

Costs Incurred

The following table summarizes Hemisphere's property acquisition costs, exploration costs and development costs for the year ended December 31, 2019:

	Property Acquisition Costs		Exploration Costs	Development Costs
	Proved Properties	Unproved Properties		
Total	-	-	-	**10,939,534**

DIVIDENDS

Hemisphere has not declared or paid any dividends since its incorporation. The future payments of dividends will depend on the earnings and financial condition of the Company and such other factors as the Board of Directors of the Company consider appropriate. See "*Risk Factors – Dividends*".

The Company is restricted, without the consent of its Lender, from declaring and paying dividends to its shareholders under the terms and conditions of its Credit Facility.

SHARE CAPITAL

Common Shares

Hemisphere has an unlimited number of common shares authorized. As of the date of this AIF there are 88,582,302 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 five 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. Stock options granted on or after September 21, 2017 are all subject to a vesting schedule, excluding 50,000 granted in March 2019 which vested immediately, whereby one-third vests immediately, one-third vests on the first anniversary, and one-third vests on the second anniversary of the grant date. Stock options granted prior to September 21, 2017 all had immediate vesting with the exception of those granted to investor relations which were subject to a vesting schedule of one-quarter of the total grant each three-month period.

As of the date of this AIF the Company has 7,084,000 stock options outstanding of which 7,084,000 have vested and are exercisable.

Warrants

As of the date of this AIF, the Company has 13,750,000 warrants outstanding.

MARKET FOR SECURITIES

The common shares of the Company are listed for trading on the TSX-V under the symbol "HME".

Common Share Trading

	Price Range		Total Volume Traded
	High	Low	
2019			
January	$0.14	$0.09	1,044,500
February	$0.14	$0.11	1,720,000
March	$0.18	$0.11	939,200
April	$0.20	$0.13	1,157,100
May	$0.17	$0.12	1,176,000
June	$0.15	$0.12	957,200
July	$0.14	$0.11	1,683,300
August	$0.12	$0.09	2,938,800
September	$0.18	$0.10	2,089,400
October	$0.17	$0.15	782,200
November	$0.17	$0.14	788,500
December	$0.22	$0.14	2,453,900
2020			
January	$0.23	$0.16	767,500
February	$0.21	$0.15	653,500
March	$0.19	$0.06	2,288,300
April 1 to 22	$0.09	$0.07	1,033,900

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, 2019 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 1, 2019	Stock options	50,000	$0.12	March 1, 2024

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.
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.

Name and Municipality of Residence	Position with Hemisphere	Director or Officer Since	Principal Occupation During the Past Five Years
Dorlyn Evancic, 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. Delta, British Columbia, 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.

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 9,872,996 common shares or approximately 11% (14% 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, 2019, 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, 2019	101,000	12,500	5,000	Nil
December 31, 2018	94,200	5,000	4,200	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, 2018.

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 2000, 1055 West Hastings Street, Vancouver, British Columbia V6E 2E9, 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

March 25, 2020

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 an Independent Qualified Reserves Evaluator 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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019 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, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue M$ (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates	December 31, 2019	Canada	-	234,513.2	-	234,513.2

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented 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) *"B.R. Hamm"*

B.R. Hamm, P. Eng.
President & CEO

Calgary, Alberta, Canada
March 25, 2020

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 23, 2020

APPENDIX "C"

Hemisphere energy corporation

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.