

**YANGARRA RESOURCES LTD.**

**ANNUAL INFORMATION FORM**

**For the Year Ended December 31, 2020**

**March 4, 2021**

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### **SCHEDULES**

SCHEDULE "A" REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES  
EVALUATOR OR AUDITOR

SCHEDULE "B" REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS  
DISCLOSURE

SCHEDULE "C" AUDIT COMMITTEE CHARTER

## ABBREVIATIONS

### Abbreviations

Oil and Natural Gas Liquids		Natural Gas	
Bbl or bbl	Barrel	Mcf or mcf	thousand cubic feet
Bbls or bbls	Barrels	Mmcf	million cubic feet
Mbbl	thousand barrels	Mcf/d or mcf/d	thousand cubic feet per day
Mmbbl	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels	Mbtu/d	thousand British Thermal Units per day
Bbl/d or bbl/d	barrels per day	MMBTU or mmbtu	million British Thermal Units
BOPD or bopd	barrels of oil per day	Bcf or bcf	billion cubic feet
NGLs	natural gas liquids	GJ	Gigajoule

### Other

BOE or boe                      barrel of oil equivalent of natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas. Disclosure provided herein in respect of boes 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 the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value.**

BOE/d, boe/d or boepd        barrel of oil equivalent per day.

In this Annual Information Form, references to "dollars" and "\$" are to the currency of Canada, unless otherwise indicated and M or M\$ means thousands of dollars.

## FORWARD-LOOKING STATEMENTS

Certain information contained in this Annual Information Form constitutes forward-looking statements and forward-looking information within the meaning of applicable securities legislation. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intend", "forecast", "plans", "guidance" and similar expressions is intended to identify forward-looking statements or information.

More particularly and without limitation, this Annual Information Form and the documents incorporated by reference herein contain forward-looking statements and information relating to the following:

- the performance characteristics of the Corporation's oil, NGLs and natural gas properties;
- oil, NGLs and natural gas production levels;
- the size of the oil, NGLs and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- the impact of COVID-19 and the associated effect of the world-wide weakness in demand for oil and gas as a result of quarantine measures;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future funds from operations;
- capital programs;
- debt levels;

- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under and changes to governmental regulatory regimes and tax laws;
- our business plans and strategy; and
- capital expenditure programs.

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

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

- weakness in the oil and natural gas industry;
- the impact of COVID-19 on the Corporation, its employees and the oil and natural gas industry generally;
- market prices of oil and natural gas;
- differentials;
- fluctuation in the supply and demand for oil and natural gas;
- operational risks and liabilities inherent in oil and natural gas operations;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- our ability to market our oil and natural gas;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- uncertainties and changes in royalty regimes;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- cyber-security issues; and
- the other factors discussed under "*Risk Factors*".

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are based on certain key expectations and assumptions made by the Corporation, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labour and services.

Although the Corporation believes that the expectations reflected in the forward-looking statements and information in this Annual Information Form and in the documents incorporated by reference herein are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources, changes in tax, royalty and environmental legislation and the risks under the heading "Risk Factors" in this Annual Information Form. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of factors and risks is not exhaustive.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are made as of the date hereof and, unless so required by applicable law, the Corporation undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise. The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are expressly qualified by this cautionary statement.

#### **Non-IFRS Measures**

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "netbacks" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. We consider "netback" to be a key measure as they demonstrate Yangarra's profitability relative to current commodity prices. Corporate netbacks are comprised of operating, field operating, funds flow from operations and net income / (loss) netbacks. Operating netback is calculated as the average sales price of its commodities (including realized gains on financial instruments) and then subtracts royalties, operating costs and transportation expenses. Field operating netback subtracts the realized gains on financial instruments, funds flow from operations netback starts with the operating netback and further deducts general and administrative costs, finance expense and adds finance income. To calculate the net income (loss) netback, Yangarra takes the funds flow netback and deducts share-based compensation expense as well as depletion and depreciation charges, accretion expense, unrealized gains on financial instruments, any impairment or exploration and evaluation expense and deferred income taxes. There is no IFRS measure that is reasonably comparable to netbacks

### **INCORPORATION AND ORGANIZATION**

Yangarra Resources Ltd. (the "**Corporation**" or "**Yangarra**") was formed on May 1, 2010 as a result of an amalgamation under the *Business Corporations Act* (Alberta) ("**ABCA**") between Yangarra and its wholly owned subsidiary, Athabaska Energy Ltd. The Corporation's predecessor entity, also called Yangarra Resources Ltd. , was formed on November 9, 2005 as a result of an amalgamation under the ABCA between TriOil Ltd. ("**TriOil**") and Yangarra Resources Inc. ("**Yangarra Predecessor**"). Effective on December 31, 2009, Yangarra Predecessor acquired all of the issued and outstanding shares of Athabaska Energy Ltd. ("**Athabaska**") by issuing 50,000,004 common shares in the capital of Yangarra Predecessor at a deemed price of \$0.05 per share (the "**Athabaska Acquisition**").

On May 30, 2014, the Corporation filed articles of amendment to effect a consolidated of the common shares of the Corporation (the "**Common Shares**") on a three old Common Shares for one new Common Share (3:1) basis.

TriOil was incorporated under the ABCA under the name "1000863 Alberta Ltd." and changed its name to "TriOil Ltd." and amended its share capital to add first and second preferred shares on September 26, 2002. TriOil amended its articles to remove its "private company" restrictions on November 13, 2002. Effective on August 13, 2004, TriOil amalgamated with Entrada Energy Inc. and continued to operate under the name "TriOil Ltd."

Yangarra Predecessor was incorporated under the ABCA under the name "324220 Alberta Ltd." and changed its name to "Ayrex Resources Ltd." on August 20, 1985. Yangarra Predecessor consolidated its share capital on a four for one (4:1) basis on May 6, 2003 and changed its name to "Yangarra Resources Inc." on June 16, 2003. Yangarra Predecessor amended and registered its restated articles to include an unlimited number of common shares and preferred shares on April 30, 2004.

The Corporation's head office and registered office is located at Suite 1530, 715 - 5th Avenue S. W. , Calgary, Alberta, T2P 2X6.

The Corporation has one wholly-owned subsidiary, "Yangarra Resources Corp." incorporated under the ABCA.

## **BUSINESS OF THE CORPORATION**

### **Three Year History**

#### *2018*

On April 6, 2018, the Corporation announced that it had increased its Credit Facility to \$150 million.

On October 3, 2018, the Corporation announced that it had increased its Credit Facility to \$175 million.

#### *2019*

On March 7, 2019, the Corporation announced that it had increased its Credit Facility to \$225 million.

On November 27, 2019, the Corporation announced that it had received Toronto Stock Exchange ("TSX") approval for the implementation of a normal course issuer bid (the "NCIB") whereby Yangarra may purchase for cancellation up to 4,268,152 Common Shares on the open market through the facilities of the TSX. As a result of market uncertainty due to the Covid-19 pandemic, in order to preserve capital, no shares were acquired under the NCIB.

#### *2020*

On June 30, 2020, the Corporation announced that it had decreased its Credit Facility to \$210 million.

### **Significant Acquisitions**

The Corporation did not complete any significant acquisitions during the most recently completed financial year.

## **DESCRIPTION OF THE BUSINESS**

### **General**

Yangarra is a growth oriented, exploration focused oil and natural gas company. The Corporation is involved in the production, exploration and development of resource properties in Central Alberta. For the year ended December 31, 2020, Yangarra's oil and gas assets averaged production of 9,888 boe/d of oil, natural gas and NGLs (compared to average production of 12,572 boe/d of oil, natural gas and NGLs for the year ended December 31, 2019). As at December 31, 2020, Yangarra owned approximately 109,579 gross (96,563 net) acres of undeveloped land. See "*Statement of Reserves Data and Other Oil and Gas Information*" in this Annual Information Form.

## Strategy

Yangarra plans to grow over the next five years by drilling its extensive Cardium acreage. The Corporation may also explore and develop its Glauconitic and Duvernay assets in Central Alberta.

Yangarra's business plan is to focus on sustainable and profitable per share growth in both cash flow from operations and net asset value. To accomplish this, the Corporation will focus on enhancing its asset base through selective land acquisitions, exploratory drilling and development drilling.

The Corporation expects to internally generate exploration and development opportunities possessing medium risk and multiple prospective productive zone potential with a prudent exposure to higher risk/reward prospects. The Corporation intends to maintain a balance between exploration, development and exploitation drilling, combined with selective acquisition opportunities that meet the Corporation's business parameters. To achieve sustainable and profitable growth, the Corporation will control the timing and costs of its projects wherever possible. Accordingly, the Corporation will seek to become the operator of its properties to the greatest extent possible. Further, to minimize competition within its geographic areas of interest, the Corporation will, after giving consideration to its risk profile, strive to maximize its working interest ownership in its properties. While the Corporation intends to have the skills and resources necessary to achieve its objectives, participation in exploration and development in the oil and natural gas industry has a number of inherent risks. See "*Risk Factors*".

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria:

- (a) risk capital required to secure or evaluate the investment opportunity;
- (b) the potential return on the project, if successful;
- (c) the likelihood of success; and
- (d) the risked return versus cost of capital.

In general, the Corporation will use a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable high levels of profitable production and financial growth.

## Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

- (a) world market forces, including the ability of OPEC and Russia to set and maintain production levels and prices for crude oil;
- (b) political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;
- (c) increases or decreases in crude oil quality and market differentials;
- (d) availability of takeaway pipeline capacity;
- (e) the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by the Corporation for its crude oil and natural gas;
- (f) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;

- (g) global and domestic economic and weather conditions;
- (h) price and availability of alternative fuels;
- (i) the effect of energy conservation measures and government regulations; and
- (j) The demand impact of COVID-19.

We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes. See "*Risk Factors – Volatility of Oil and Gas Prices and Markets*", "*Risk Factors – Weakness in the Oil and Gas Industry*", "*Risk Factors – Hedging*" and "*Information Concerning the Oil and Natural Gas Industry – Curtailment*".

### **Revenue Sources**

For the year ended December 31, 2020, 68% of the revenue from Yangarra's properties before royalties was derived from oil and NGLs and 32% was derived from natural gas (compared to 82% of the revenue being derived from oil and NGLs and 18% being derived from natural gas for the year ended December 31, 2019). Production is sold to marketers at delivery points in or close to the producing field.

### **Need to Replace and Grow Reserves**

The future oil and natural gas production of the Corporation and, therefore, future cash flows, are highly dependent upon ongoing success in exploring on the Corporation's current and future undeveloped land base, exploiting the current producing properties and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, reserves and production will decline over time as reserves are depleted.

The business of discovering, developing, or acquiring reserves is capital intensive. To the extent cash flows from the Corporation's operating activities are insufficient and external sources of capital become limited or unavailable, the ability for the Corporation to make the necessary capital investments to maintain and expand its oil and natural gas reserves may be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace and grow production at acceptable costs.

### **Competition**

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation will actively compete for capital, skilled personnel, undeveloped land, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

### **Environmental Policies**

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. Key environmental considerations include air quality and reduction of greenhouse gas emissions, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment, remediation and reclamation). These practices and procedures apply to our employees

and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policies.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation.

Our environmental management program and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program is monitored by our health, safety and environmental committee and includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an asset integrity program; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response and clean-up program; a fugitive emission survey and repair program; and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as our oil and gas properties are abandoned. In 2019, expenditures for normal compliance with environmental regulations were not material and expenditures for above normal compliance were \$0.9 million.

## **Personnel**

As at December 31, 2020, Yangarra had 64 employees (14 head office & 50 field). As at the date hereof, Yangarra has 65 employees (13 head office & 51 field).

## **RISK FACTORS**

The holding of securities in the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision relating to the Corporation's securities. **The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.**

## **COVID-19**

On March 11, 2020, the World Health Organization declared the COVID-19 outbreak a global pandemic. COVID-19's impact on global markets was significant through the year and as the situation continues to rapidly evolve, the magnitude of its effects on the economy, demand of oil and gas, Yangarra's financial and operational performance and on our personnel is uncertain at this time. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. Unexpected developments in financial markets, regulatory environments, or consumer behaviour may also have adverse impacts on our results, business, financial condition or liquidity, for a substantial period of time.

Significant health and safety measures have been implemented at our offices, facilities and work sites, grounded in the recommendations of public health officials. These include restricting all travel, mandating self-isolation for returned travelers and any employees exhibiting symptoms or exposed to the virus, implementing physical distancing parameters between individuals, increasing cleaning and sanitization in workplaces, and where possible, instructing employees to work remotely to reduce interpersonal contact. The energy business has been deemed an essential service in all the jurisdictions where the Corporation operates.

The Corporation continues to closely monitor the COVID-19 situation and should the duration, spread or intensity of the pandemic further develop in 2021, further negative impacts on commodity prices, personnel, market supply and demand can be expected. These factors may impact the Company's operating plan, liquidity and cash flows, and the valuation of long-lived assets. The Corporation's ability to obtain additional capital including, but not limited to, debt and equity financing may be adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals due to the pandemic.

The extent to which the COVID-19 pandemic continues to impact our results, business, financial condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the development and widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the development and distribution of an effective vaccine also continues to raise uncertainty.

### **Weakness in the Oil and Gas Industry**

2020 was a tumultuous year for the oil and gas industry as whole, and market events and conditions, including global excess oil and natural gas supply, COVID-19 and drastic reductions in worldwide demand for oil and gas products resulting in historically low oil prices, actions taken by the Organization of the Petroleum Exporting Countries ("OPEC") and Russia, sanctions against Iran and Venezuela, market volatility, isolationist and punitive trade policies, and disruptions in Asia, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-hydrocarbon sentiment, have caused a significant decrease in the valuation of oil and gas companies and a significant decrease in confidence in the oil and gas industry. See "*Risk Factors – Political Uncertainty*" and "*Risk Factors – COVID-19*". These difficulties have been exacerbated in Canada by government actions and the resultant uncertainty surrounding regulatory, tax and royalty changes that has been and may continue to be implemented by the federal government. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry. Lower commodity prices may also affect the volume and value of the Corporation's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce the Corporation's cash flow which could result in a reduced capital expenditure budget. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future or if it is able to do it may be on unfavourable and highly dilutive terms.

### **Exploration, Development and Production Risks**

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

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing

(including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and funds 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. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us.

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

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

### **Credit Facilities**

The amount authorized under the Corporation's Credit Facility is dependent on the borrowing base determined by its lenders. The lenders under the Amended and Restated Credit Agreement use the Corporation's reserves, commodity prices, and other factors, to periodically determine the Corporation's borrowing base. There remains a substantial amount of uncertainty with commodity prices. Further reductions in commodity prices could result in a reduction to the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facilities. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

### **Volatility of Oil and Gas Prices and Markets**

The Corporation's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of the Corporation including, but not limited, to the world economy and OPEC's ability to adjust supply to world demand, government regulation, political stability and the availability of alternative fuel sources. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand including LNG egress to global markets, economic performance, weather conditions and availability and pricing of alternative fuel sources. In addition, the marketability of the production depends upon the availability and capacity of gathering systems and pipelines, the effect of federal and provincial regulation on such production and transportation and general economic conditions. All of these factors are beyond the control of the Corporation.

Decreases in oil and natural gas prices typically result in a reduction of the Corporation's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Corporation's reserves. Any substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in the Corporation's net production revenue, cash flows and profitability and have a material adverse effect on the Corporation's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation will in part be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

From time to time the Corporation has and may in the future 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, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. 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.

### **Additional Funding Requirements**

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experience unexpected and/or prolonged deterioration, the Corporation's access to additional funding may be required.

Because of global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to 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 Corporation's petroleum properties may require additional financing and there no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production of the Corporation's properties.

### **Development of Additional Reserves**

The Corporation's future success is dependent upon its ability to explore, develop or acquire additional oil and natural gas reserves that are economically recoverable at attractive acquisition prices. Except to the extent that the Corporation conducts successful activities or acquires properties containing proved reserves, or both, the proved reserves and production will generally decline as reserves are produced. If prevailing oil and natural gas prices were to increase significantly, the Corporation's costs to add reserves could be expected to increase. The

drilling of oil and natural gas wells involves a high degree of risk, especially the risk of a dry hole or of a well that is not sufficiently productive to provide an economic return on the capital expended to drill the well.

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which the Corporation has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three-dimensional seismography, reservoir simulation studies and horizontal drilling may, where appropriate, may be used by the Corporation to improve its ability to find, develop and produce oil and natural gas.

### **Political Uncertainty**

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. During its tenure, the former American administration withdrew the United States from the Trans-Pacific Partnership and passed sweeping tax reform, which, among other things, significantly reduced U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The former U.S. administration also took action to reduce regulation, which affected relative competitiveness of other jurisdictions.

In addition, the United States Mexico Canada Agreement (the "USMCA") which replaced the former North American Free Trade Agreement ("NAFTA") was ratified on July 1, 2020 and may impact our business See "*Information Concerning the Oil and Natural Gas Industry – International Trade Agreements*". The newly-inaugurated Biden administration in the U.S. has indicated that it will roll-back certain policies of the former administration and has taken action to cancel TC Energy Corporation's Keystone X.L. pipeline permit. While it is unclear which other legislation or policies of the former Trump administration will be rolled-back and if such roll-backs will be a priority of the new administration in light of the ongoing COVID-19 pandemic, any future actions taken by the new U.S. administration could 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 us.

In addition to the changing political landscape in the United States, the impact of the United Kingdom's exit from the European Union are slowly emerging and some impacts may not become apparent for some time. 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 our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our 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. The United Conservative Party government in Alberta is supportive of the Trans Mountain Pipeline expansion project and, although there has been notable opposition from the government of British Columbia, the federal Government remains in support of the project. 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. See "*Information Concerning the Oil and Natural Gas Industry – Transportation Constraints and Market Access*".

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. Lack of political consensus, 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 "*Information Concerning the Oil and Natural Gas Industry – Climate Change Regulation*", "*Information Concerning the Oil and Natural Gas Industry – Transportation Constraints and Market Access*", "*Information Concerning the Oil and Natural Gas Industry – Curtailment*" and "*Information Concerning the Oil and Natural Gas Industry – International Trade Agreements*".

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development - particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt our activities. See "*Information Concerning the Oil and Natural Gas Industry – Transportation Constraints and Market Access – Natural Gas*".

## **Title**

Although satisfactory title reviews of the Corporation's properties are conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Corporation to a property.

## **Environmental Concerns**

The operation of oil and natural gas wells involves a number of natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions resulting in liability to the Corporation and possibly liability to third parties. Companies operating in the oil and natural gas industry are subject to extensive environmental regulation which provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in fines or the issuance of clean-up orders. See "*Information Concerning the Oil and Natural Gas Industry – Environmental Regulation*". The Corporation will make reasonable provision for well abandonment and reclamation where appropriate; however, there can be no assurance that such provision will be sufficient to satisfy all such obligations. No sinking fund or reserve will be established for the purpose of site reclamation or abandonment costs.

## **Regulatory**

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which controls and regulations may be amended from time to time. See "*Information Concerning the Oil and Natural Gas Industry*". Governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

## **Royalty Regimes**

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

## **Hydraulic Fracturing**

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 our 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 we are ultimately able to produce from our reserves.

## **Climate Change**

GHG emission regulations in Canada and the US are evolving, but as these regulations are established they are likely to have a significant impact on organizations involved in the oil sands regions, including Yangarra. It is difficult to assess the overall impact these regulations will have on Yangarra at this time but it could result in increased costs to comply, delays in having projects approved and potentially a reduction in demand for oil from these regions, all of which could have a material negative impact on our business.

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect our business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations may materially adversely affect Yangarra's business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by Yangarra or by consumers of Yangarra's products. The imposition of such measures might negatively affect Yangarra's costs and prices for Yangarra's products and have an adverse effect on earnings and results of operations.

Future federal legislation, including potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from Yangarra's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Corporation is unable to predict the impact of emissions reduction legislation on the Corporation and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

## **Reserves Estimates**

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

In accordance with applicable securities laws, the Corporation's independent reserves consultants have used both constant and forecast price and cost estimates in calculating reserves quantities for the Corporation's reserves. 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 therefrom will vary from the estimates contained in the applicable engineering reports. The reserves reports are based in part on the assumed success of activities intended to be undertaken in future years. The reserves and

estimated cash flows to be derived therefrom contained in the applicable engineering reports will be reduced to the extent that such activities do not achieve the level of success assumed in the engineering reports.

### **Purchase of Reserves**

Acquisitions of resource issuers and resource assets by the Corporation will be based on engineering and economic assessments made by management and reviewed by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other governmental levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. In particular, changes in the prices of and markets for oil and natural gas from those anticipated at the time of making such assessments will affect the value of the Corporation's securities. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than anticipated.

### **Depletion of Reserves**

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on the Corporation's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited, and from time to time production declines can be severe under certain conditions.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired.

There can be no assurance that the Corporation will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

### **Foreign Exchange**

Operating costs incurred by the Corporation are generally paid in Canadian dollars. World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Corporation's net production revenue. To the extent that the Corporation has engaged or will in the future engage in risk management activities related to commodity prices and foreign exchange rates, through entry into oil and natural gas price hedges and forward foreign exchange contracts or otherwise, the Corporation will be subject to unfavourable price changes and credit risks associated with the counter-parties with which it contracts.

### **Potential Conflicts of Interest**

Some of the directors of the Corporation are also directors of other oil and natural gas companies, which may from time to time be in competition with the Corporation for working interest partners, property acquisitions, or other limited resources. Where required by law, appropriate disclosure of such conflicts will be made by the applicable directors. In particular, the Corporation follows the provisions of the ABCA. These provisions state that in the event that a director has an interest in a contract or proposed contract or agreement, such director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise permitted by the ABCA.

### **Competition**

The oil and natural gas industry is intensely competitive and the Corporation will compete for joint venture partners, capital, reserves acquisitions and skilled industry personnel with a substantial number of other companies

which have greater resources. Many such companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a worldwide basis and as such have greater and more diverse resources upon which to draw. There is also competition between the oil industry and other industries with respect to the supply of energy and fuel to industrial, commercial and individual customers.

### **Liability Management**

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 AB LMR Program administered by the AER are currently underway. In July 2020, the Government of Alberta announced that the AB LMR and associated programs will be replaced by the AB LMF. Other changes to the requirements of liability management programs, may result in significant increases to our compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in *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. As a result of the decision, the Government of Alberta implemented the Liabilities Management Statutes and Amendment Act, which places the financial burden of a defunct licensee's abandonment and reclamation obligations in the working interest partners of the defunct licensee and may order the AER Orphan Fund to assume custody of wells or sites without a responsible owner to expedite the cleanup process.

In addition, the AB LMF Program may prevent or interfere with our 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 asset. See "*Information Concerning the Oil and Natural Gas Industry – Liability Management Rating Programs*".

### **Changes in Legislation**

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry, will not be changed in a manner which will adversely affect the Corporation. There can be no assurance that tax authorities having jurisdiction will agree with how the Corporation calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of the Corporation.

### **Enforcement of Operating Agreements**

Operations of the wells located on properties not operated by the Corporation are generally governed by operating agreements that typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation.

### **Substantial Capital Requirements**

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, the Corporation may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly, including transactions involving the issuance of securities,

which may be dilutive. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

### **Additional Funding Requirements**

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to the Corporation.

### **Issuance of Debt**

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

### **Insurance**

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

### **Reliance on Operators and Key Employees**

To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Corporation will be largely dependent upon the performance of its management and key employees. The Corporation does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Corporation.

### **Delays in Business Operations**

In addition to the usual delays in payments by purchasers of oil and natural gas to the Corporation or to the operators, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

## **Permits and Licences**

The operations of the Corporation may require licences and permits from various governmental authorities. There can be no assurance that the issuer will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects.

## **Aboriginal Claims**

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of the Corporation's assets, however, if a claim arose and was successful, it could have an adverse effect on the Corporation and its operations.

## **Seasonality**

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and 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 swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and potential declines in production of oil and gas of the Corporation.

## **Income Taxes**

The Corporation will file all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all 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 Corporation, whether by re-characterization of exploration and development expenditures, or otherwise, such reassessment may have a negative impact on current and future taxes payable and such impact may be material.

## **Credit Facility Arrangements**

We currently have a credit facility and are required to comply with covenants under our Credit Facility which include certain financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under our Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The impact of the Supreme Court of Canada's decision in the Redwater case on lending practices in the crude oil and natural gas sector and actions taken by secured creditors and receivers/trustees of insolvent borrowers has not yet been determined but could affect lending practices as secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced.

If our lenders require repayment of all or a portion of the amounts outstanding under our Credit Facilities for any reason, including for a default of a covenant, there is no certainty that we would be in a position to make such repayment. Even if we are able to obtain new financing in order to make any required repayment under our Credit Facilities, we may not be on commercially reasonable terms, or terms that are acceptable to us. If we are unable

to repay amounts owing under Credit Facilities, the lenders under our Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

## **Hedging**

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

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

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

## **Acquisition Risk**

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

Additionally, the oil and gas property acquisition business is highly competitive, and is populated with many companies, large and small, with the capital and expertise to evaluate, purchase, and exploit producing and non-producing opportunities. Even with capital and experience, the industry risks of drilling dry holes and cost overruns are significant. Environmental compliance is an increasingly complex and costly burden to entry for many new exploration areas, and often times, and even if permits are obtained, they are sufficiently restrictive that a property cannot be explored to its full potential. The Corporation may not be able to locate acquisition opportunities, or finance those that the Corporation can. The Corporation offer no assurance that its entry into this business activity will be successful.

## **Management of Growth**

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

## **Expiration of Licenses and Leases**

Our properties are held in the form of licences and leases and working interests in licences and leases. If we, or the holder of the licence or lease, fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence

or lease will be met. The termination or expiration of our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our business, financial condition, results of operations and prospects.

### **Litigation**

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

### **Third Party Credit Risk**

The Corporation is or 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 the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations.

### **Carbon Pricing Risk**

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Information Concerning the Oil and Natural Gas Industry – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The 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 our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with our counterparts who operate in jurisdictions where there are less costly carbon regulations.

### **Reputational Risk Associated with Our Operations**

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

related litigation against governments and fossil fuel companies may impact our reputation. See "*Risk Factors – Climate Change*".

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

### **Non-Governmental Organizations**

The oil and natural gas exploration, development and operating activities conducted by us may, at times, be subject to public opposition. Such public opposition could expose us to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. See "*Information Concerning the Oil and Natural Gas Industry – Transportation Constraints and Market Access*". There is no guarantee that we will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require us to incur significant and unanticipated capital and operating expenditures.

### **Changing Investor Sentiment**

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

### **Information Technology Systems and Cyber-Security**

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

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to business activities or our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive

information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If we become a victim to a cyber phishing attack it could result in a loss or theft of our financial resources or critical data and information, or could result in a loss of control of our technological infrastructure or financial resources. Our employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to our computers.

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

## **STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION**

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated and was prepared on February 9, 2021. The effective date of the Statement is December 31, 2020. All currency values are in Canadian dollars (unless otherwise specified).

The tables below summarize the Corporation's crude oil, NGLs and natural gas reserves and the present value of future net cash flows associated with such reserves, as at December 31, 2020, as evaluated and prepared by Deloitte LLP ("**Deloitte**") independent petroleum engineers of Calgary, Alberta in their report dated February 9, 2021, based on forecasted price assumptions (the "**2020 Reserves Report**"). The 2020 Reserves Report has been prepared in accordance with the standards in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in National Instrument 51-101 and the COGE Handbook. The tables below summarize the data contained in the 2020 Reserves Report and, as a result, may contain slightly different numbers than the 2020 Reserves Report due to rounding. All future cash flows are stated prior to provision for indirect costs and after deduction of royalties, estimated future capital expenditures and well abandonment costs. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The Corporation's crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided. In the various reserves related tables included herein, columns may not add due to rounding.

The Corporation is required to pay royalties to the Crown or other royalty owners and receives royalties from various working interest parties for commodities produced. Crown royalty payments are subject to change and any changes may have an adverse impact on the profitability of a project.

Attached as Schedule "A" to this Annual Information Form is the report on reserves data of Deloitte and attached as Schedule "B" to this Annual Information Form is the report of management and directors of the Corporation on the oil and gas reserves disclosure.

## Petroleum and Natural Gas Reserves and Net Present Value

The following table summarizes Deloitte's estimates of the Corporation's oil and natural gas reserves at December 31, 2020, based on forecast price assumptions and calculated without discount.

### SUMMARY OF OIL AND GAS RESERVES BASED ON FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2020

Reserves Category	Light and Medium Oil (Mbbbl)		Conventional Gas (MMcf)		Shale Gas (MMcf)		Natural Gas Liquids (Mbbbl)		Total BOE (Mboe)	
	W.I. Gross	Net	W.I. Gross	Net	W.I. Gross	Net	W.I. Gross	Net	W.I. Gross	Net
Proved Developed Producing	4,576	4,146	79,807	73,880	1,147	1,090	4,686	4,043	22,754	20,684
Proved Developed Non-Producing	1,870	1,597	47,868	43,554	0	0	2,748	2,215	12,595	11,072
Proved Undeveloped	13,527	11,881	206,195	190,647	5496	5,221	12,276	10,432	61,084	54,957
<b>Total Proved</b>	<b>19,972</b>	<b>17,623</b>	<b>333,870</b>	<b>308,081</b>	<b>6,643</b>	<b>6,311</b>	<b>19,709</b>	<b>16,691</b>	<b>96,434</b>	<b>86,713</b>
Probable	12,154	10,113	207,953	189,575	8,132	7,450	12,959	10,253	61,127	53,204
<b>Total Proved Plus Probable</b>	<b>32,126</b>	<b>27,737</b>	<b>541,823</b>	<b>497,657</b>	<b>14,775</b>	<b>13,761</b>	<b>32,668</b>	<b>26,944</b>	<b>157,561</b>	<b>139,917</b>

The following table is a summary of net present values of future net revenues associated with such reserves at December 31, 2020, based on forecast price assumptions before and after deducting income taxes, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%. Future net revenue includes estimated abandonment costs related to wells and production facilities required to produce reserves.

### SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS AS OF DECEMBER 31, 2020

Reserves Category	Before Income Taxes				
	0.0% (M\$)	5.0% (M\$)	10.0% (M\$)	15.0% (M\$)	20.0% (M\$)
Proved Developed Producing	506,456	387,937	316,329	268,787	234,994
Proved Developed Non-Producing	263,656	198,336	160,446	135,571	117,893
Proved Undeveloped	1,054,480	758,251	573,429	450,352	363,872
<b>Total Proved</b>	<b>1,824,592</b>	<b>1,344,523</b>	<b>1,050,203</b>	<b>854,710</b>	<b>716,759</b>
Probable	1,354,564	722,397	439,246	290,103	202,846
<b>Total Proved Plus Probable</b>	<b>3,179,157</b>	<b>2,066,921</b>	<b>1,489,449</b>	<b>1,144,813</b>	<b>919,604</b>

Reserves Category	After Income Taxes				
	0.0% (M\$)	5.0% (M\$)	10.0% (M\$)	15.0% (M\$)	20.0% (M\$)
Proved Developed Producing	465,397	363,382	300,496	257,995	227,321
Proved Developed Non-Producing	203,302	153,503	124,859	106,157	92,913
Proved Undeveloped	810,282	575,654	429,031	331,598	263,391
<b>Total Proved</b>	<b>1,478,980</b>	<b>1,092,538</b>	<b>854,386</b>	<b>695,750</b>	<b>583,625</b>
Probable	1,043,632	552,846	333,463	218,373	151,407
<b>Total Proved Plus Probable</b>	<b>2,522,613</b>	<b>1,645,384</b>	<b>1,187,849</b>	<b>914,122</b>	<b>735,032</b>

The following table sets forth elements of future net revenue attributed to Proved Reserves and Proved Plus Probable Reserves of the Corporation as of December 31, 2020, based on forecast price assumptions and calculated without discount.

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)  
BASED ON FORECAST PRICES AND COSTS  
AS OF DECEMBER 31, 2020**

<b>Reserves Category</b>	<b>Revenue (M\$)</b>	<b>Royalties (M\$)</b>	<b>Operating Costs (M\$)</b>	<b>Investment Costs (M\$)</b>	<b>Well Abandonment Costs (M\$)</b>	<b>Future Net Revenue Before Income Taxes (M\$)</b>	<b>Future Income Taxes (M\$)</b>	<b>Future Net Revenue After Income Taxes (M\$)</b>
Proved Developed Producing	826,065	60,229	245,139	90	14,150	506,456	41,060	465,397
Proved Developed Non-Producing	400,246	48,517	84,647	3,426	-	263,656	60,354	203,302
Proved Undeveloped	2,186,584	202,056	497,514	416,051	16,484	1,054,480	244,198	810,282
<b>Total Proved</b>	<b>3,412,895</b>	<b>310,802</b>	<b>827,300</b>	<b>419,566</b>	<b>30,634</b>	<b>1,824,592</b>	<b>345,612</b>	<b>1,478,980</b>
Probable	2,538,993	320,228	651,802	202,059	10,340	1,354,564	310,932	1,043,632
<b>Proved Plus Probable</b>	<b>5,951,888</b>	<b>631,030</b>	<b>1,479,102</b>	<b>621,625</b>	<b>40,974</b>	<b>3,179,157</b>	<b>656,544</b>	<b>2,522,613</b>

The following table sets forth the net present value of future net revenues by production group attributed to Proved and Proved plus Probable Reserves of the Corporation as of December 31, 2020, based on forecast price assumptions.

**NET PRESENT VALUES OF FUTURE NET REVENUE  
BY PRODUCTION GROUP  
BASED ON FORECAST PRICES AND COSTS  
AS OF DECEMBER 31, 2020**

<b>Reserves Category</b>	<b>Production Group</b>	<b>Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M\$)</b>	<b>Net Reserves Unit Value Before Income Taxes (Discounted at 10%/Year)</b>
<b>Proved</b>	Associated and Non-Associated Gas (including by-products)	111,389	\$1.81/mcf
	Shale Gas	1,729	\$0.27/mcf
	Light and Medium Oil (including solution gas and by-products)	937,085	\$55.27/bbl
	<b>TOTAL</b>	<b>1,050,203</b>	\$37.16/boe
<b>Proved Plus Probable</b>	Associated and Non-Associated Gas (including by-products)	153,397	\$1.45/mcf
	Shale Gas	14,427	\$1.05/mcf
	Associated and Non-Associated Gas (including by-products)	1,321,625	\$49.54/bbl
	<b>TOTAL</b>	<b>1,489,449</b>	\$ 31.99/boe

## **Definitions**

"**W.I. Gross**" reserves are the Corporation's working interest (operating or non-operating) share before deducting royalty obligations and without including any royalty interests of the Corporation.

"**Co. Share Gross**" reserves are the Corporation's working interest (operating or non-operating) share and before deducting royalty obligations but including any royalty interests of the Corporation.

"**Net**" reserves are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations plus any royalty interests of the Corporation.

"**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according with the level of certainty associated with the estimates and may be sub-classified based on development and production status.

"**Production**" is the cumulative quantity of petroleum that has been recovered at a given date.

"**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. At least 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves is the targeted level of certainty.

"**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. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probably reserves is the targeted level of certainty.

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

"**Developed Producing Reserves**" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Non-Producing Reserves**" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

## **Pricing Assumptions**

### **Forecast Prices Used in Estimates**

The forecast price and market forecasts prepared by Deloitte are based on information available from numerous government agencies, industry publication, oil refineries, natural gas marketers, and industry trends. The prices are Deloitte's best estimate of how the future will look, based on the many uncertainties that exist in both the domestic Canadian and international petroleum industries. Deloitte considers the current monthly trends, the

actual and trends for the year to date, and the prior year actual in determining the forecast. The crude oil and natural gas forecasts are based on yearly variable factors weighted to higher percent in current data and reflecting a higher percent to the prior year historical. These forecasts are Deloitte's interpretation of current available information and while they are considered reasonable, changing market conditions or additional information may require alteration from the indicated effective date.

Inflation forecasts and exchange rates, an integral part of the forecast, have also been considered.

	Price Inflation Rate	Cost Inflation Rate	Cdn to US Exchange Rate
<b>2020</b>	0.8%	0.8%	\$0.754
<b>2021</b>	0.0%	0.0%	\$0.770
<b>2022</b>	2.0%	2.0%	\$0.780
<b>2023</b>	2.0%	2.0%	\$0.800
<b>2024</b>	2.0%	2.0%	\$0.800
<b>2025 beyond</b>	2.0%	2.0%	\$0.800

Oil, NGL, and natural gas base case prices, utilized by Deloitte in the Deloitte Reserve Report were as follows:

#### Price Forecast Used in Estimates

Year	Oil		Natural Gas		Natural Gas Liquids		
	WTI Cushing (Oklahoma) (\$US/bbl)	Edmonton City Gate 40° API (\$Cdn/bbl)	Alberta Reference – Gas Prices (\$Cdn/mcf)	Alberta AECO – Gas Prices (\$Cdn/mcf)	Pentanes + Condensate Edmonton (\$Cdn/bbl)	Butanes Edmonton (\$Cdn/bbl)	Propane Edmonton (\$Cdn/bbl)
<b>Historical</b>							
2013	\$97.91	\$93.36	\$2.98	\$3.17	\$103.52	\$77.44	\$38.54
2014	\$93.26	\$94.00	\$4.22	\$4.50	\$101.47	\$59.43	\$42.93
2015	\$48.69	\$57.00	\$2.56	\$2.69	\$55.15	\$33.70	\$5.35
2016	\$43.15	\$52.22	\$1.93	\$2.16	\$52.43	\$31.45	\$8.71
2017	\$50.88	\$61.88	\$2.13	\$2.19	\$63.65	\$40.98	\$27.92
2018	\$62.20	\$68.89	\$1.24	\$1.52	\$77.14	\$46.90	\$29.65
2019	\$56.80	\$68.78	\$1.45	\$1.82	\$65.83	\$20.82	\$14.81
2020	\$39.90	\$45.91	\$2.00	\$2.45	\$65.83	\$20.82	\$14.81
<b>Forecast</b>							
2021	\$46.00	\$53.25	\$2.40	\$2.65	\$53.25	\$23.95	\$18.65
2022	\$54.05	\$62.80	\$2.45	\$2.70	\$62.80	\$34.55	\$28.25
2023	\$59.80	\$68.30	\$2.50	\$2.75	\$68.30	\$44.35	\$30.75
2024	\$61.00	\$69.65	\$2.55	\$2.80	\$69.65	\$45.25	\$31.35
2025	\$62.25	\$71.05	\$2.60	\$2.85	\$71.05	\$46.15	\$32.00
2026	\$63.50	\$72.50	\$2.65	\$2.95	\$72.50	\$47.10	\$32.65

**Notes:**

- All prices are in Canadian dollars except WTI and NYMEX which are in U.S. dollars.
- Edmonton City Gate prices based on light sweet crude posted at major Canadian refineries (40 Deg. API <0.5% Sulphur).
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point.
- 1 Mcf is equivalent to 1 mmbtu.
- Alberta gas prices, except AECO, include an average cost of service to the plant gate.

Weighted average historical prices realized by Yangarra for the year ended December 31, 2020 before transportation were \$2.28/Mcf for natural gas, \$18.45/Bbl for NGLs and \$47.64/Bbl for oil.

## Reconciliations of Changes in Reserves

The following table sets out a reconciliation of the changes in the Corporation's reserves as at December 31, 2020 against such reserves at December 31, 2019 based on forecast prices and cost assumptions:

	Light and Medium Oil			Natural Gas Liquids		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(Mstb)	(Mstb)
Opening Balance	19,186.1	12,549.7	31,735.8	17,996.4	13,277.5	31,273.9
Production	-978.5	-	-978.5	-755.6	-	-755.6
Technical Revisions	-328.6	-569.8	-898.4	1,235.2	152.2	1,387.4
Extensions	2,102.2	179.2	2,281.4	1,398.4	92.3	1,490.7
Economic Factors	-8.8	-5.2	-14.0	-165.4	-562.7	-728.1
Closing Balance	19,972.4	12,153.9	32,126.4	19,709.0	12,959.3	32,668.2

	Conventional Gas			Shale Gas		
	Gross Proved	Gross Probable	Gross Proved Plus Probable	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)
Opening Balance	283,084.6	196,747.4	479,832.0	6,290.0	7,595.7	13,885.7
Production	-12,839.2	-	-12,839.2	-92.1	-	-92.1
Technical Revisions	39,261.3	9,629.9	48,891.1	445.0	536.0	981.2
Extensions	24,363.2	1,607.5	25,970.6	-	-	-
Economic Factors	-0.2	-31.4	-31.6	-	-	-
Closing Balance	333,869.6	207,953.4	541,823.0	6,643.0	8,131.8	14,774.8

	MBOE		
	Gross Proved	Gross Probable	Gross Proved Plus Probable
	(Mboe)	(Mboe)	(Mboe)
Opening Balance	85,411.6	59,884.4	145,296.0
Production	-3,889.3	-	-3,889.3
Technical Revisions	7,524.3	1,276.7	8,801.0
Extensions	7,561.2	539.4	8,100.6
Economic Factors	-174.3	-573.1	-747.4
Closing Balance	96,433.5	61,127.4	157,560.9

## Timing of Initial Undeveloped Reserves Assignment

The following table sets forth the gross volumes of proved undeveloped reserves, by each product type, attributed to the Corporation's assets for the years ended December 2020, 2019, and 2018, based on forecast prices and costs.

### Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbbl)
2018	13,622	157,656	10,278
2019	13,225	195,141	12,149
2020	13,527	211,691	12,276

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in for production or wells not yet drilled at year end that are adjacent to producing wells. In addition, such reserves

may relate to planned infill drilling locations. Plans are included in the Deloitte report to develop these reserves. The future timing of these undeveloped reserves reflects an orderly operational development of the reserves considering infrastructure limitations and corporate portfolio management.

Deloitte has assigned 54,957 Mboe of proved undeveloped reserves in the 2020 Reserves Report under forecast prices and costs, together with approximately \$420 million of associated undiscounted future capital expenditures. Proven undeveloped capital spending in the first two forecast years of the 2020 Reserves Report accounts for approximately \$222 million or 53%, of the total forecast.

### **Probable Undeveloped Reserves**

Year	Light and Medium Oil (Mbbbl)	Natural Gas (non-associated & associated) (MMcf)	Natural Gas Liquids (Mbbbl)
2018	13,051	162,049	10,739
2019	12,553	205,010	13,324
2020	12,154	216,085	12,959

Deloitte has assigned 61,127 Mboe of probable undeveloped reserves and has allocated future development capital of approximately \$202 million to all probable undeveloped reserves with none scheduled for the first two years.

### **Significant Factors or Uncertainties Affecting Reserves Data**

Probable undeveloped reserves are generally adjacent to proven undeveloped reserves, lands contiguous to production or indicated by analogy to be productive. In general, once proved and/or probable undeveloped reserves are identified, Yangarra schedules them into development plans within five years.

A number of factors that could result in delayed or cancelled development are: changing economic conditions (due to pricing, operating and capital expenditure fluctuations); changing technical conditions (for example production anomalies such as water breakthrough or accelerated depletion); multi-zone developments (for example, 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.

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and cost changes. The Corporation's estimates are based on current production forecast, prices and economic conditions.

As additional data and circumstances change, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either downward or upward as warranted. As new geological, production and economic data is incorporated into the process of estimated reserves the accuracy of the reserve estimate improves.

The Corporation's reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Corporation's control.

The Corporation's oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company which have been disclosed in financial statements and management's discussion and analysis as filed on SEDAR ([www.sedar.com](http://www.sedar.com)) and this Annual Information Form.

## Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) (\$MM)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) (\$MM)
2021	101.7	101.7
2022	120.4	120.4
2023	67.7	67.7
2024	68.8	68.8
2025	61.0	77.0
Thereafter	-	186.0
Total for all years undiscounted	419.6	621.6

Yangarra expects that such funding of its share of future development on capital expenditure programs will be primarily obtained from internally generated cash flow and equity financings and debt facilities.

## Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest or a royalty interest as at December 31, 2020, which are producing or which the Corporation considers to be capable of production. All wells set forth in the table are located in Alberta.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
<b>Central Alberta</b>				
Producing	152	133.1	15	10.5
Shut-in	-	-	34	28.2

### Notes:

- Shut-in wells means wells which are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons.
- Gross wells are defined as the total number of wells in which the Corporation has an interest.
- Net wells are defined as the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

## Property Overview

The following is a description of the major oil and natural gas properties, and facilities in which the Corporation had an interest as of December 31, 2020. Production volumes represent the working interest share of the Corporation before the deduction of royalties. Reserve amounts are stated, before deduction of royalties, at December 31, 2020 based on escalating cost and price assumptions, as set forth in the 2020 Reserves Report.

### Central Alberta Area

Yangarra holds working interests ranging from 9% to 100% in multiple sections in this area with high potential Glauconitic (47 gross (26 net) sections), Cardium (166 gross (148 net) sections), Viking, Second White Specs (45 gross (29.0 net) sections), Rock Creek and Eilerslie zones.

The field is located 60 miles west of Red Deer, near the town of Rocky Mountain House, Alberta. Yangarra has a 100% ownership in a compressor station in the Willesden Green area of Central Alberta capable of 16 Mmcf/d constructed in early 2004, an oil battery was added to this facility in 2016. Yangarra has a compressor facility in the Ferrier area of Central Alberta that was built early in 2013, this compressor station is capable of 22 Mmcf/d. An oil battery and truck service facility were constructed in December 2017 just north of the town of Rocky

Mountain House. A compressor station in the West Ferrier area of Central Alberta was constructed in May/June of 2018 capable of 35 Mmcf/d. Yangarra constructed a compressor facility in the Chedderville area in early 2019 capable of 25 Mmcf/d. All facilities process third party volumes providing the Corporation with incremental profit. The O'Chiese area has two compressors station capable of 10 Mmcf/d. Yangarra has a 100% interest in a field office with accommodation, a shop and storage.

As of December 31, 2020, 167 gross wells (143.6 net wells) are producing.

### Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land holdings as of December 31, 2020.

<u>Location</u>	<u>Gross (hectares)</u>	<u>Net (hectares)</u>
Alberta	44,345	39,078

At December 31, 2020, there was no material commitments associated with the Corporation's undeveloped land holdings. The Corporation has rights to explore, develop, and exploit undeveloped land holdings that will expire.

### Significant Factors to Properties with No Attributed Reserves

The Corporation will develop properties with no attributed reserves over the next 5-10 years.

### Exploration and Development

In 2021, the Corporation intends to undertake a portfolio of exploration and development projects to capture and advance projects that provide opportunities utilizing multi-well pads and horizontal drilling with multi-stage fracturing technology. The Corporation's 2021 capital program is anticipated to be equivalent to operating cash flows and the existing bank facilities.

### Additional Information Concerning Abandonment and Reclamation Costs

The 2020 Reserves Report includes average well abandonment and reclamation costs of \$60,000 per well, depending on the formation and depth of the well. The abandonment costs are based on average costs from the wells we abandoned during 2020. The 2020 Reserves Report does not address well site reclamation for existing wells, pipeline right-of-ways, and facility abandonment/salvage costs including potential environmental concerns.

Yangarra has 201 gross wells for which it expects to incur abandonment and restoration costs. These costs included well abandonment and surface lease reclamation. The estimated total abandonment and reclamation costs, forecast net of estimated salvage value, under the proved reserves category is \$13,386,500 (undiscounted). The total proved plus probable abandonment and reclamation costs are \$23,600,400 (undiscounted). 100% of such amounts were deducted as abandonment costs in estimating future net revenue of the Corporation in respect of proved and proved plus probable reserves as disclosed above. Estimated abandonment costs are included in the 2020 Reserves Report as a deduction in arriving at future net revenue.

### Forecast Prices and Costs – Proved (M\$)

Year	Abandonment Costs (Undiscounted)
2021	-
2022	-
2023	-
2024	-
2025	-
Thereafter	13,386.5
Total	13,386.5

## Forecast Prices and Costs – Proved Plus Probable (M\$)

Year	Abandonment Costs (Undiscounted)
2020	-
2021	-
2022	-
2023	-
2024	-
Thereafter	23,600.4
Total	23,600.4

## Forward Contracts

As at December 31, 2020, the Corporation was committed to the following commodity price risk contracts:

Year	Volume	Term	Reference	Type	Strike Price
<u>Oil</u>					
2021	500 bbl/d	Jan to Mar	US\$ WTI	Swap	USD \$42.30/bbl
2021	500 bbl/d	Jan to Jun	US\$ WTI	Swap	USD \$44.70/bbl
<u>Gas</u>					
2020/2021	5,000 GJ/d	Jun 2020 to Mar 2021	AECO	Swap	CDN \$2.40/GJ
2020/2021	5,000 GJ/d	Nov 2020 to Mar 2021	AECO	Collar	CDN \$2.75/GJ - \$3.40/GJ
2021	5,000 GJ/d	Jan 2021 to Dec 2021	AECO	Swap	CDN \$2.805/GJ
<u>Propane</u>					
2021	200 bbl/d	Jan to Dec	Conway - C3 to Mont Belvieu C3	Basis Swap	Minus USD 0.01/Gallon

## Tax Horizon

Yangarra was not required to pay income tax in 2020 and based on current tax pools, projected cash flow, and projected exploration costs, the Corporation does not expect to be taxable in 2021.

## Costs Incurred

For the year ended December 31, 2020, exploration and development capital expenditures were \$51 million. The breakdown for the Corporation's capital expenditures during 2020 is presented below:

	(\$000's)
Land, acquisitions and lease rentals	\$ 324
Drilling and completion	44,816
Geological and geophysical	640
Equipment	4,226
Other asset additions	1,087
Total	<u>\$ 51,093</u>

## Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Yangarra participated during the year ended December 31, 2020.

<b>Exploration Wells</b>	<u>Gross</u>	<u>Net</u>	<b>Development Wells</b>	<u>Gross</u>	<u>Net</u>
Light and Medium Oil	-	-	Light and Medium Oil	13	13
Natural Gas	-	-	Natural Gas	-	-
Service	-	-	Service	-	-
Dry	-	-	Dry	-	-
<b>Total</b>	<b>-</b>	<b>-</b>	<b>Total</b>	<b>13</b>	<b>13</b>

## Production Estimates

The following table sets out the volume of Yangarra's production estimated for the first year reflected in the estimates of future gross revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	<b>Total Proved Reserves</b>			<b>Total Proved + Probable Reserves</b>		
	Light and medium oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Light and medium oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)
Central Alberta	6,813	87,488	5,037	6,870	88,755	5,110

\* Table includes fields that account for more than 20% of the estimated production reflected in the estimate of future net reserves.

## Production History

The following tables set forth the Corporation's average daily production volume before deductions of royalties payable to others, and crude oil, NGLs and natural gas prices. Also shown are royalties, production and transportation costs, and average netbacks for the period January 1, 2020 – December 31, 2020.

### Average Daily Production

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil (bbl/d)	3,548	2,510	2,132	2,264
Natural gas (mcf/d)	38,712	33,214	27,445	30,322
Natural gas liquids (bbl/d)	2,122	1,830	1,703	1,825
<b>Total (BOE/d)</b>	<b>12,122</b>	<b>9,876</b>	<b>8,409</b>	<b>9,170</b>

### Average Prices Received per Unit – (Excluding commodity contracts, before deduction of royalties)

Three months ended	March 31	June 30	Sept 30	Dec 31
Light and medium oil (\$/bbl)	52.05	31.31	49.49	55.13
Natural gas (\$/mcf)	16.59	13.98	18.96	24.43
Natural gas liquids (\$/bbl)	2.11	2.25	2.47	2.75
<b>(\$ / BOE)</b>	<b>24.92</b>	<b>18.05</b>	<b>24.03</b>	<b>26.96</b>

### Royalties Paid per Unit

Three months ended	March 31	June 30	Sept 30	Dec 31
<b>Total royalties (\$/BOE)</b>	<b>1.49</b>	<b>0.35</b>	<b>1.26</b>	<b>1.52</b>

### Production and Transportation Costs

Three months ended	March 31	June 30	Sept 30	Dec 31
<b>Total costs (\$/BOE)</b>	<b>6.67</b>	<b>6.32</b>	<b>6.10</b>	<b>6.04</b>

## Netbacks Received

Three months ended	March 31	June 30	Sept 30	Dec 31
Total netbacks (\$/BOE)	16.71	11.46	16.67	19.39

## Production Volume by Field

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2020:

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/d)
Central Alberta	2,611	32,404	1,876	9,888

## Uncertainty of Reserves Estimates

The reserve and recovery information contained in the 2020 Reserves Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the independent estimates of Deloitte.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. The reserve and cash flow information set forth herein represent estimates only. The reserves and estimated future net cash flow from the Corporation's assets have been independently evaluated effective December 31, 2020 by Deloitte. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success in the evaluations.

## DIRECTORS AND OFFICERS OF THE CORPORATION

The name, province and country of residence and principal occupation for the last five years of each of the directors and executive officers of the Corporation are as follows:

<u>Name and Municipality of Residence</u>	<u>Position</u>	<u>Principal Occupation</u>	<u>Director or Officer Since</u>
James G. Evaskevich <sup>(4)</sup> Calgary, Alberta	President, Chief Executive Officer, and Director	President and Chief Executive Officer of the Corporation since December 2001.	December 19, 2001
James A. Glessing <sup>(4)</sup> Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of the Corporation since December 1, 2010. Prior thereto CFO & VP Finance of North Peace Energy (2007-2010).	December 1, 2010
Randall J. Faminow Calgary, Alberta	Vice President, Land	VP Land of the Corporation since October 18, 2011. Prior thereto VP, Land for Spry Energy Ltd (2007-2011).	October 18, 2011

<b>Name and Municipality of Residence</b>	<b>Position</b>	<b>Principal Occupation</b>	<b>Director or Officer Since</b>
Lorne D. Simpson <sup>(4)</sup> Cochrane, Alberta	Vice President, Operations	VP Operations of the Corporation since April 11, 2013. Prior thereto Manager of Drilling and Completions for the Corporation (2012-2013), Supervisor, Drilling Operations with PetroBakken Energy Ltd. (2010-2012), Manager Drilling and Completions with Open Range (2009-2010).	April 11, 2013
Gurdeep Gill <sup>(4)</sup> Calgary, Alberta	Vice President, Business Development	VP Business Development of the Corporation since August 1, 2018. Prior thereto head of investment banking at AltaCorp Capital Inc. (2011-2018).	August 1, 2018
Trish Olynyk <sup>(4)</sup> Calgary, Alberta	Vice President, Finance	VP Finance of the Corporation since April 9, 2019. Prior thereto controller of the Corporation (2005-2019).	April 9, 2019
Gordon A. Bowerman <sup>(1)(2)(3)</sup> Calgary, Alberta	Director	President of Cove Resources Ltd. , a private oil and gas company based in Calgary, since 1987.	December 19, 2001
Robert D. Weir <sup>(1)(2)(3)</sup> Calgary, Alberta	Director	President of Weir Resource Management Ltd. , a private company based in Calgary, since 1981.	November 11, 2003
Frederick (Ted) L. Morton <sup>(1)(2)(3)</sup> Calgary, Alberta	Director	Professor at the University of Calgary (1981 – present) and MLA, Foothills Rockyview (2004 – 2012).	February 24, 2014
Neil M. Mackenzie <sup>(1)(2)(3)</sup> Calgary, Alberta	Director	Retired Businessman, prior thereto, Vice-President of Blackstone Drilling Fluids Ltd. (2010 – 2018).	February 24, 2014

**Notes:**

- (1) Member of the Audit Committee.
- (2) Member of the Corporate Governance and Nominating Committee.
- (3) Member of the Compensation Committee.
- (4) Member of the Management Committee

Each director of the Corporation shall hold office until the next annual meeting of shareholders or until their successors are duly elected or appointed pursuant to the Corporation's by-laws, unless the director's office is earlier vacated.

**Shareholdings of Directors and Executive Officers**

As at December 31, 2020, the directors and officers of the Corporation, as a group, beneficially owned or controlled, directly or indirectly, 14,536,705 Common Shares, representing approximately 17% of the issued and outstanding Common Shares as at that date. The directors and executive officers, as a group, also held options to purchase 6,581,119 Common Shares as at December 31, 2020.

The fully diluted holdings of directors and executive officers, as a group were 21,117,824 Common Shares, or approximately 22% of the Common Shares that were outstanding on a fully diluted basis, at December 31, 2020.

**Cease Trade Orders**

To the knowledge of management of the Corporation, no director or executive officer as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Corporation), 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 hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) 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 management of the Corporation, no director or executive officer of the Corporation is, as of the date hereof, or has been, within 10 years before the date hereof, a director or executive officer of any company that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal to 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.

To the knowledge of management of the Corporation, no director or executive officer of the Corporation has, within 10 years before the date hereof, 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 its assets.

## **Penalties and Sanctions**

To the knowledge of management of the Corporation, no director or executive officer or shareholder holding a sufficient number of common shares to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority, or has been subject to any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor making an investment decision.

## **Conflicts of Interest**

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject to in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial or director positions with other oil and natural gas companies whose operations may, from time to time, be in direct competition with those of the Corporation or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Corporation. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract. In addition, the directors are required to act honestly and in good faith with a view to the best interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation.

## **AUDIT COMMITTEE**

The purpose of the Corporation's audit committee is to provide assistance to the Board of Directors (the "**Board**") in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. It is the objective of the audit committee to maintain a free and open means of communications among the Board, the independent auditors and the senior management of the Corporation.

The full text of the audit committee's charter is attached hereto as Schedule "C" and forms part of this Annual Information Form.

### **Composition of the Audit Committee**

The audit committee is comprised of Gordon Bowerman (Chair), Robert Weir, Frederick (Ted) Morton and Neil Mackenzie. Each of the members are independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**"). Each of the members is financially literate within the meaning of section 1.6 of NI 52-110.

## Relevant Education and Experience

The following relevant education and experience of the members of the Audit Committee have been used in assessing their financial literacy and are relevant to the performance of their responsibilities as audit committee members:

*Gordon Bowerman, B.A.*– Mr. Bowerman has over 40 years experience in the oil and gas industry, including various experience in production, land, accounting, asset purchases and sales. Mr. Bowerman currently is the President of a private oil and gas company.

*Robert Weir, P.Eng* – Mr. Weir has over 30 years experience in the oil and gas industry, including as the President of Weir Resource Management Ltd., a private company based in Calgary, since 1981.

*Frederick (Ted) Morton B.A. PhD* – Mr. Morton held various positions in the Alberta Government included Minister of Energy, Minister of Finance and Enterprise, and Minister of Sustainable Resources.

*Neil Mackenzie* –Mr. MacKenzie is or has been a director and officer and has been on the Audit Committee of various public companies, including Canyon Services Group Inc. and Challenger Energy Corp. and was until 2018 a Vice-President at Blackstone Drilling Fluids Ltd., a private oil and gas drilling fluids company. In addition, Mr. MacKenzie held senior position in oil and gas companies from 1976-2010.

## Pre-Approval Policies and Procedures

The audit committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

## Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Committee to nominate or compensate an external auditor (currently, MNP LLP, Chartered Accountants) not adopted by the Board.

## Reliance on Certain Exemptions

Since the effective date of NI 52-110, the Corporation has not relied on the exemptions contained in sections 2.4 (*De Minimis Non-audit Services*), 3.2 (*Initial Public Offerings*), 3.4 (*Events Outside Control of Member*), 3.5 (*Death, Disability or Resignation of Audit Committee Member*), of NI 52-110, or an exemption, in whole or in part, granted under Part 8 of NI 52-110.

## External Auditor Service Fees (By Category)

<u>Year Ended</u>	<u>Audit Fees</u>	<u>Audit Related Fees</u>	<u>Tax Fees</u>	<u>All Other Fees</u>
December 31, 2020	\$121,000 <sup>(1)</sup>	\$nil	\$nil	\$nil
December 31, 2019	\$121,000 <sup>(1)</sup>	\$nil	\$nil	\$nil

### Notes:

- (1) Includes \$36,000 for quarterly reviews.  
(2) Includes \$36,000 for quarterly reviews.

## DESCRIPTION OF CAPITAL STRUCTURE

### Credit Facility

The Corporation's \$210 million Credit Facility is comprised of a \$185 million revolving syndicated facility and a \$25 million revolving operating facility. The Credit Facility has a termination date of May 29, 2022. Prior to any

anniversary date, being May 31 of each year, we may request an extension of the then current termination date, subject to approval by the banks.

The Credit Facility bears interest at the banks' prime lending or bankers' acceptance rates plus applicable margins. The applicable margin charged by the bank is dependent upon our debt to earnings before interest, taxes, depreciation and amortization (EBITDA) ratio for the most recent two quarters.

The Company is subject to a single financial covenant requiring an adjusted working capital ratio above 1:1 (current assets plus the undrawn availability under the revolving facility, divided by the current liabilities less the drawn portion of the revolving facility and excluding unrealized commodity contracts). The Company was in compliance with this covenant as at December 31, 2020 and December 31, 2019. The facility is secured by a general security agreement over all assets of the Company.

## Share Capital

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

The Corporation is authorized to issue an unlimited number of Common Shares, without nominal or par value, and an unlimited number of First Preferred Shares (the "**First Preferred Shares**") and the Second Preferred Shares in the capital of the Corporation, both issuable in series (the "**Second Preferred Shares**", and together with the First Preferred Shares, the "**Preferred Shares**"). As of the date of this Annual Information Form, 85,379,725 Common Shares and nil Preferred Shares are issued and outstanding.

## Common Shares

Holders of Common Shares are entitled to: (a) one vote per post-consolidated Common Share at all meetings of shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board, as a class equally with the holders of the Preferred Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Common Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, share rateably, together with the holders of Preferred Shares and of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

## First Preferred Shares

Holders of First Preferred Shares shall: (a) not be entitled to receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) be entitled to receive dividends if, as and when declared by the Board on the First Preferred Shares as a class in preference to the holders of the Second Preferred Shares and Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends; and (c) be entitled to, in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive in preference to the holders of the Second Preferred Shares and Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

## Series A First Preferred Shares

The Corporation previously had a series of First Preferred Shares outstanding ("**Series A First Preferred Shares**") Holders of Series A First Preferred Shares shall: (a) not be entitled to receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) be entitled to receive dividends: (i) on a semi-annual basis within 30 days of the first and second fiscal-year halves of the Corporation, which can be paid in the form of cash or Common Shares at the election of the Board, with the deemed price of such Common Shares to be the

Market Price (as such term is defined in the Corporate Finance Manual of the TSX Venture Exchange) of such Common Shares at the time of settlement on the First Preferred Shares; (ii) as a class in preference to the holders of the Second Preferred Shares and Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends; and (iii) each Series A First Preferred Share shall be entitled to a cumulative dividend at the rate of 5% per annum on the stated amount of \$1.00 per Series A Preferred Share (the "**Stated Amount**") of such Series A First Preferred Share; (c) be entitled to, in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive an amount equal to the Stated Amount per Series A First Preferred Share plus any declared but unpaid dividends prior to any payment or distribution to any other class of shares of the Corporation; and (d) have the option, exercisable not earlier than the date that is 18 months after the Series A Preferred Shares are issued, to force the Corporation to redeem or purchase all or any of the Series A First Preferred Shares held by such holder. In addition, the Corporation has the right to redeem the Series A First Preferred Shares at any time in cash at the price equal to the Stated Amount plus any declared but unpaid dividends.

## Second Preferred Shares

Holders of Second Preferred Shares shall not be entitled to: (a) receive notice of, to attend or vote at any meeting of the shareholders of the Corporation; (b) receive dividends if, as and when declared by the Board on the First Preferred Shares as a class in preference to the holders of the Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares in respect of the dividends, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Second Preferred Shares in respect of dividends; and (c) in the event of any liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, or any other distribution of its assets for the purpose of winding up its affairs, receive in preference to the holders of the Common Shares, and any other shares of the Corporation ranking junior to the First Preferred Shares, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes ranking in priority to the Second Preferred Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

## DIVIDENDS

The Corporation has not declared or paid any dividends on the Common Shares. Any decision to pay dividends on such shares in the future will be made by its Board on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. It is not the current intention of the Corporation to pay any dividends on the Common Shares in the near future.

## MARKET FOR SECURITIES

### Trading Price and Volume

The Common Shares have been listed and posted for trading on the Toronto Stock Exchange ("**TSX**") since June 27, 2014. Prior thereto, the Common Shares were listed and posted for trading on the TSX Venture Exchange. The following table sets out the price range for, and trading volume of the Common Shares as reported by the TSX for the periods indicated:

	Trading Price		Volume Traded
	High	Low	# of shares
January 2020	\$ 1.53	\$ 1.08	6,594,900
February 2020	\$ 1.17	\$ 0.79	8,857,800
March 2020	\$ 0.90	\$ 0.27	13,028,600
April 2020	\$ 0.56	\$ 0.33	6,570,900
May 2020	\$ 0.71	\$ 0.40	5,844,700
June 2020	\$ 0.88	\$ 0.58	7,218,700
July 2020	\$ 0.72	\$ 0.58	2,290,800
August 2020	\$ 0.66	\$ 0.59	3,526,200
September 2020	\$ 0.62	\$ 0.42	2,918,300

	Trading Price		Volume Traded
	High	Low	# of shares
October 2020	\$ 0.53	\$ 0.43	3,473,900
November 2020	\$ 0.65	\$ 0.43	6,005,100
December 2020	\$ 0.74	\$ 0.58	3,345,800

### ESCROWED SECURITIES

No securities of the Corporation are currently escrowed.

### INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

#### Government Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and our oil and gas operations are subject to various Canadian federal, provincial, territorial, and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations.

More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning our operations, the spacing of wells, unitization and pooling of properties, and royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of our operations. The Corporation cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may also restrict the rates of flow of oil and gas wells below actual production capacity.

Although Yangarra does not expect that these controls and regulations will affect the operations of Yangarra in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and Yangarra is unable to predict what additional legislation or amendments may be enacted.

#### Pricing and Marketing

##### *Oil*

Producers of crude oil, bitumen, and bitumen blend negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of such commodities. The price depends, in part, on product quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms, and the world price of oil.

### *Natural Gas*

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms.

The government of Alberta also regulates the volume of natural gas that may be removed from the province for consumption elsewhere, based on such factors as reserve availability, transportation arrangements and other market considerations.

### *Natural Gas Liquids*

The price of condensate and other natural gas liquids ("NGLs") sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms.

### **Exports from Canada**

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

### **Transportation Constraints and Market Access**

#### *Pipelines*

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 permitting difficulties in the United States and is now expected to be in-service in the latter half of 2021.

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

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. In January 2021 the newly elected Biden administration revoked the Presidential Permit for the Keystone XL Pipeline effectively terminating the project.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, potentially forcing the lines comprising this segment of the pipeline system to be shut down by May 2021. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards.

#### *Marine Tankers*

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

#### *Crude Oil and Bitumen by Rail*

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020 that trains hauling more than 20 cars carrying dangerous goods, including oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in April 2020 and replaced in November 2020. The speed limits and other requirements established in November 2020 ministerial order will remain in place until permanent rule changes are approved.

#### *Natural Gas*

Natural gas prices in Alberta 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. TC Energy received Government of Canada approval for an expansion to its NOVA gas transmission system in October 2020, with pipeline construction activities expected to begin in January 2021 and a target in-service date of April 2022. The CER has started a process to determine whether it will extend the temporary service protocol. Final argument took place in late January 2021.

Additionally, while a number of liquefied natural gas (“LNG”) export plants have been proposed in 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 proponents of the LNG Canada LNG export terminal announced a positive final investment decision to proceed with the project. Pre-construction activities began in November 2018, with a planned completion target of 2025.

In late 2019, TC Energy announced that it would sell a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction closed in May 2020. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet’suwet’en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding.

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 Oil and Gas 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 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 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 its final investment decision until mid-2021.

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 Impact Assessment Agency of Canada (“**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 first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. The regulatory hearing process

is currently underway and a final decision from the CER is not expected until mid-2021. If Enbridge receives CER approval, it intends to hold the open season by the end of 2021.

### **International Trade Agreements**

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

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

### **Curtailment**

In December 2018, the Government of Alberta announced that it would mandate a short-term and temporary curtailment of provincial oil and bitumen production. Curtailment first took effect on January 1, 2019. As contemplated in the Curtailment Rules, the Government of Alberta, on a monthly basis, required oil and bitumen producers producing more than 20,000 Bbls/d to limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

As of December 2020, monthly oil production limits are no longer in effect. However, the Curtailment Rules, which were set to be repealed on December 31, 2020, have been extended such that the Government of Alberta retains the ability to impose production limits if needed.

### **Gathering and Processing Facilities and Pipeline Systems**

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work because of actions taken by regulators could also affect the Corporation's production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

The Federal Government has signaled that it plans to review the National Energy Board approval for large projects. This may cause the timeframe for project approvals for current and future applications to increase.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

## **Land Tenure**

Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses, and permits and regulations as legislated by the respective Provincial and Federal governments. Lease terms vary in length, usually from two to five years. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Oil produced from oil sands owned by the Province of Alberta is produced under provincial Crown oil sands leases. Two types of oil sands agreements are issued under the Oil Sands Tenure Regulation, 2010 made under the *Mines and Minerals Act*: (i) permits, issued for a five-year term, which can be converted to leases; and (ii) leases, issued for an initial 15-year term, which can be continued as to all or any portion the Minister of Energy may determine. The regulation requires that exploration or development activity be undertaken according to prescribed levels of evaluation or production. Permits may generally be converted to leases provided certain minimum levels of exploration have been achieved and all lease rentals have been timely paid. A lease may generally be continued after the initial term as to all or any portion the Minister of Energy may determine, provided certain minimum levels of exploration or production have been achieved and all lease rentals have been timely paid. The surface rights required for pipelines, upgraders and cogeneration and other facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

Jurisdictions in western Canada, including the provinces of Alberta, and Saskatchewan have legislation in place for mineral rights reversion to the Crown where formations cannot be shown to be capable of production at the end of their primary lease term. Such legislation may also include mechanisms available to energy companies to "continue" lease terms for non-productive lands, having met certain criteria as laid out in the relevant legislation.

Oil and natural gas can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

## **Royalties and Incentives**

### *General*

For crude oil, natural gas and related production from Federal or Provincial government lands, the royalty regime is a significant factor in the profitability of our production. Crown royalties payable in respect of crown lands are determined by governmental regulation and are typically calculated as a percentage of the value of gross production. The value of the production and the rate of royalties payable generally depend on prescribed reference prices, well productivity, geographical location, the field discovery rate and the type of product produced.

Royalties payable on production from privately owned lands are determined by negotiations between the mineral owner and the resource owner, although production from such lands is subject to certain provincial taxes and royalties. Any such royalties (or royalty-like interests) are carved out of the working interest owner's interest through non-public transactions and are often referred to as overriding royalties, gross overriding royalties, net profit interests or net carried interests.

From time to time, provincial governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

In addition, the federal government may from time to time provide incentives to the oil and gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, which will provide oil and gas businesses with eligible Canadian development expenses and Canadian oil and gas property expenses with a first year deduction of one and a half times the deduction that is otherwise available. The federal government also announced in late 2018 that it will make \$1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package, however, is mostly in the form of loans and is earmarked for crude oil and natural gas projects related to economic diversification as well as direct funding for clean growth crude oil and natural gas projects.

## *Alberta*

Alberta has adopted a new, modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. 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 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 is 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 horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator ("**AER**") on an annual basis.

Producers pay a flat royalty rate of 5 percent 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 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 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.

The Old Framework is applicable to all conventional 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 oil production under the Old Framework range from a base rate of 0% to a cap of 40%.

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. 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%.

Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production 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. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is four percent of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

### **Incentive Programs**

The new Enhanced Hydrocarbon Recovery Program (the "**EHR Program**") began January 1, 2017 and replaced the previous royalty framework. The EHR Program is intended to promote incremental production through enhanced recovery methods and consists of two main components. The first component targets tertiary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or other approved methods. The second component targets secondary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by water flooding, gas cycling, gas flooding, polymer flooding or other approved methods. Under both components of the program, a company pays a flat royalty of 5 per cent on crude oil, natural gas and natural gas liquids produced from wells in an approved scheme for a limited benefit period. After the benefit period ends, wells in these schemes are subject to normal royalty rates under the Modernized Framework.

The new Emerging Resources Program (the "**ERP**") began January 1, 2017. The ERP is intended to encourage industry to open up new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. For the purposes of the ERP, a project consists of a defined geographic area, target formation, set of wells and associated infrastructure. Wells that receive program benefits pay a flat royalty rate of 5% until their combined revenue equals their combined program specific cost allowances established under the ERP, which will replace the standard Drilling and Completion Cost Allowance under the Modernized Framework in respect of such wells. After achieving payout of the specific cost allowance, wells are subject to normal royalty rates under the Modernized Framework.

### **Environmental Regulation**

As an operator of oil and natural gas properties in Canada, we are subject to stringent federal, provincial, territorial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas exploration, production, and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper abandonment of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations. 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 ("**CO<sub>2</sub>e**"), 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**").

The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative and policy considerations while adjudicative functions fall to independent commissioners. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA and the hearing is expected to take place in the first half of 2021.

### *Alberta*

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) and the *Oil and Gas Conservation Act* (Alberta). Environmental compliance in Saskatchewan is governed in general by the *Environmental Management and Protection Act* (Saskatchewan) and the *Oil and Gas Conservation Act* (Saskatchewan). Further federal environmental legislation is embodied in the *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012*.

The Corporation currently operates or lease, and has in the past operated or leased, a number of properties that have been used for the exploration and production of oil and gas. Although Yangarra utilizes and has utilized standard industry operating and disposal practices, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have

been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed wastes or remediate property contamination, or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

The Corporation may be affected by the Lower Athabasca Region Plan ("**LARP**") under the Alberta *Land Stewardship Act*, which came into effect on September 1, 2012 and is currently being implemented. LARP is a legislative instrument equivalent to regulations and will be binding on the government of Alberta and provincial regulators, including those governing the oil and gas industry. LARP is the first of an anticipated seven regional land-use plans in the province and applies to over two million hectares of land and, among other things, implements management frameworks for air emissions, water use, and land disturbance to control cumulative environmental effects of industrial development.

On September 1, 2012, framework for air quality, surface water quality and groundwater came into force, subjecting future and existing and future operations in the region to more onerous environmental constraints and stringent operating parameter. As part of these frameworks, parties may be required to participate in regional monitoring and report on the progress of implementation. Further, conversation areas established under LARP may impact some oil sands license holders in the region, as there is the potential for specific oil sands leases to be cancelled by the government. Should such a situation occur, the Alberta government would be responsible for compensating affected license holders.

On February 3, 2012 the government of Alberta and the government of Canada released the Joint Canada-Alberta Implementation Plan for Oil Sands Monitoring (the "**Monitoring Plan**"). The Monitoring Plan is designed to provide an improved understanding of the potential cumulative environmental effects of oil sands development and will increase air, water, land and biodiversity monitoring in the oil sands region. The Monitoring Plan is expected to be phased in over a three-year period and funding will be provided by industry. To support the Monitoring Plan industry has agreed to provide aggregate funding of up to \$50 million a year. On October 17, 2012, the government of Alberta announced that it will establish an independent arm's-length environmental monitoring agency in the province. The independent agency is expected to begin work in the oil sands region with a focus on integrated and coordinated monitoring of land, air, water and biodiversity.

The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. A recent example of this trend is the high-level of regulatory attention that the practice of hydraulic fracturing continues to receive in various jurisdictions. The Province of Alberta has recently announced its intention to adopt mandatory disclosure requirements and an online registry for hydraulic fracturing activities. Additionally, the AER, recently released a new Hydraulic Fracturing Directive, effective August 21, 2013, which sets out AER requirements for managing the subsurface integrity of wells associated with hydraulic fracturing. While Yangarra believes that it is in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on the Corporation, the Corporation cannot give any assurance that it will not be adversely affected in the future.

The Corporation has established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which it operates. Yangarra employs an environmental, health, and safety department whose responsibilities include providing assurance that operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although Yangarra maintains pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

## **Accountability and Transparency**

The federal Extractive Sector Transparency Measures Act (the "**ESTMA**") imposes mandatory reporting requirements on certain entities engaged in the commercial development of oil, gas or minerals, which includes exploration, extraction and holding permits to explore or extract. All companies subject to ESTMA are required to report payments over \$100,000 made to any level of a Canadian or foreign government, including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders) and infrastructure improvement payments. These categories are distinct and regardless of the aggregate payment amount, one or more individual categories must reach the \$100,000 threshold for reporting to be required.

Any persons or entities found in violation of the ESTMA (which includes making a false report, failing to make the report public or failing to maintain records for the prescribed period) can be fined up to \$250,000 for each day that the offence continues. There is a further fine of up to \$250,000 for any person or entity who has structured payments in order to avoid the obligation to report such payments under the ESTMA. Officers or directors who authorized or acquiesced in the commission of an offence can be subject to personal liability, regardless of whether the entity for which they acted has been prosecuted or convicted. The ESTMA contains a due diligence defence whereby no person will be found guilty of an offence under the ESTMA if the person can establish that he or she exercised due diligence to avoid committing the offence. Additionally, there is a five year limitation period within which proceedings must be brought for offences under the ESTMA.

## **Climate Change Regulation**

Our exploration and production facilities and other operations and activities emit GHGs which may require us to comply with federal and/or provincial GHG 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 or mitigate our effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our 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. 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 us to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to our premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, we 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 hydrocarbons which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the hydrocarbon 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 recent years, climate change advocacy groups have attempted to bring legal action against various levels of government for climate-related harms.

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 our operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas production, resulting in a decrease in our profitability and a reduction in the value of our assets or requiring asset impairments for financial statement purposes. See "*Information Concerning the Oil and Natural Gas Industry – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*",

*"Risk Factors – Reputational Risk Associated with our Operations"* and *"Risk Factors – Changing Investor Sentiment"*.

#### *Federal (Canada)*

In December 2015, Canada and 195 other countries that are members of the United Nations Framework Convention on Climate Change met in Paris, France and signed the Paris Agreement on climate change. The stated objective of the Paris Agreement is to hold "the increase in global average temperature to well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius." The countries which agreed to the Paris Agreement committed to meeting every five years to review their individual progress on GHG emissions reductions and to consider amendments to non-binding individual country targets. Canada is required to report and monitor its GHG emissions, though the implementation of such reporting and monitoring has yet to be determined. The Paris Agreement also contemplates that by 2020 the parties thereto will develop a new market-based mechanism related to carbon trading, which is expected to be based largely on lessons learned from the Kyoto Protocol. The Government of Canada has announced that it will develop a country-wide approach to implementing the Paris Agreement in 2016.

The Corporation is unable to predict the impact of the Paris Agreement on its operations. It is possible that mandatory emissions reduction requirements may have a material adverse effect on the Corporation's financial condition, results of operations and cash flow.

Over the last several years, the federal government has undertaken a number of initiatives to achieve domestic GHG reductions. These measures include regulations, codes and standards, targeted investments, incentives, tax measures and programs that directly reduce GHG emissions.

On October 3, 2016 the Government of Canada announced a pan-Canadian approach to the pricing of GHG emissions. The federal plan provides all Canadian provinces and territories a year to introduce their own carbon pricing models of either a cap and trade program or a carbon tax meeting a standard to be prescribed, failing which the federal government will begin to levy its own carbon tax on a broad set of emission sources. The initial default carbon tax is expected to begin at \$10 per tonne of GHG emissions on January 1, 2018 and increase by \$10 per tonne per year until it reaches \$50 per tonne in 2022.

Six provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories. The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal carbon-pricing regime took effect in Alberta on January 1, 2020. Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. The Saskatchewan and Ontario references have advanced in parallel where the appeal Courts ruled in favour of the constitutionality of the federal carbon tax. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and such court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled appeals, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

In addition, on June 29, 2016 Canada joined the United States and Mexico in agreeing to reduce methane emissions from the oil and gas sector by up to 45% by 2025 by developing and implementing federal regulations for both existing and new sources of venting and fugitive methane emissions. Previously, on March 10, 2016 Canada and the United States committed to take action on methane emissions through federal regulations as expeditiously as possible. The federal methane regulations are expected to be published in 2017.

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, but will not come into force until 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 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 the September 23, 2020 Throne Speech, the federal government has indicated that it intends to make a number of investments that will help it achieve net-zero emissions by 2050, including investments intended to: (i) improve transit options; (ii) make zero-emissions vehicles more affordable; (iii) expand electric vehicle charging infrastructure across the country; (iv) launch a fund that will help attract investments in the development of zero-emissions technology, including a corporate tax cut of 50% for companies participating in this initiative; (v) develop a Clean Power Fund that will, in part, help regions transition to cleaner sources of power generation; and (vi) support continued investment in the development and implementation of renewable and clean energy technologies. Specific program details have not yet been announced.

On November 19, 2020, the federal government introduced the Canadian Net-Zero Emissions Accountability Act in Parliament. If passed, this Act will bind the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making.

## Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the Climate Leadership Act (the "**CLA**") 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 CO<sub>2</sub>e 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 CO<sub>2</sub>e 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.

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 CO<sub>2</sub> 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.

### **Liability Management Rating Programs**

The AER administers a Liability Management Rating Program (the "**AB LMR Program**"), which is currently undergoing changes, including a name change to the "Liability Management Framework" (the "**AB LMF**"). The AB LMR Program is a liability management program governing most conventional upstream oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LFP**"), and the Licensee Liability Rating Program (the "**AB LLR Program**"). 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 licensee, must reduce its liabilities or provide the AER with a security deposit. Failure to do so may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**").

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. The Orphan Fund was originally conceived to be bankrolled exclusively by licensees in the AB LLR Program and AB OWL Program who contribute to a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan fund approximately \$335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered \$113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB 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.

In response to the increase in orphaned oil and gas sites and the environmental risks associated therewith, the AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information. 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 they can meet their abandonment and reclamation obligations, such as by posting security or reducing their existing obligations.

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

Additionally, the Government of Alberta announced in July 2020 that the AB LMF will replace the AB LMR Program and its constituent programs. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LMR Program and establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of oil and gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require mandatory annual minimum payment towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

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

The AER has published a draft of an amended Directive 067 to implement some of these changes (the "**Draft Directive**"), and has issued a call for feedback on the Draft Directive that will be open until mid-February 2021. The changes introduced by the Draft Directive include building on the AER's corporate and financial disclosure requirements for parties who wish to acquire, hold or transfer licences in Alberta, and broadening the AER's discretion to withhold or revoke licensees' privileges if they are assessed as posing an "unreasonable risk". The feedback that the AER receives will be considered in the determination of the final revised Directive 067, and the rollout of the AB LMF may require changes to other Directives as well. As a result, our ongoing and future transactions may be affected in this period of transition, resulting in processing delays for licence transfers and regulatory uncertainty as the criteria and requirements for licensees are subject to change.

To address abandonment and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. Beginning in 2015, for example, the AER oversaw the Inactive Well Compliance Program, a five-year intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, 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 through industry collaboration and economies of scale.

Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets.

### **Federal and Provincial Support for Liability Management**

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, the federal government pledged \$1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its \$1 billion share of the federally provided funds through the Site Rehabilitation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a \$200 million loan to Alberta's Orphan Fund. The Government of British Columbia is disbursing its \$120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program and the Legacy Sites Reclamation Program. In Saskatchewan, \$400 million in federal funding will be allocated through the Accelerated Site Closure Program ("ASCP"). The first phase of the ASCP will make \$100 million available to eligible service companies to conduct abandonment and reclamation work. Further tranches of the ASCP, up to \$300 million, will be made available in the future.

### **Changing Investor Sentiment**

A number of factors, including the effects of the use of hydrocarbons on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments 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 our Board of Directors, management and employees.

Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in us, or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of our assets which may result in an impairment change.

## **LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

### **Legal Proceedings**

In the normal conduct of operations, there are other pending claims by and against the Corporation. Litigation is subject to many uncertainties, and the outcome of individual matters is not predictable with assurance. In the opinion of management, based on the advice and information provided by its legal counsel, the final determination of these other litigations will not materially affect the Corporation.

### **Regulatory Actions**

To the knowledge of management of the Corporation, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

## **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

None of the directors, executive officers of the Corporation, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10 percent of any class or series of outstanding voting securities of the Corporation, nor any associate or affiliate of the foregoing persons had any material interest, direct or indirect, in any transaction during the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

## **TRANSFER AGENT AND REGISTRAR**

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal office located in Calgary, Alberta.

## **MATERIAL CONTRACTS**

The Corporation did not enter into any material contracts outside the ordinary course of business within the most recently completed financial year or prior thereto that are still in effect.

## **INTERESTS OF EXPERTS**

Deloitte prepared the 2020 Reserves Report referred to in this Annual Information Form. As of the date hereof, the partners, employees and consultants of Deloitte who participated in or who were in a position to directly influence the preparation of the 2020 Reserves Report do not hold any of the securities of the Corporation.

MNP LLP has confirmed that it is independent of the Corporation in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

## **ADDITIONAL INFORMATION**

Additional information relating to the Corporation may be found on SEDAR at [www.sedar.com](http://www.sedar.com). Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Corporation's information circular dated March 13, 2020. Additional financial information is also provided in the Corporation's consolidated financial statements and MD&A for the year ended December 31, 2020.

**SCHEDULE "A"**  
**REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES**  
**EVALUATOR OR AUDITOR**

To the Board of Directors of Yangarra Resources Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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 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 sets forth the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2020, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Management /Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Yangarra Resources Ltd. Reserve Estimation and Economic Evaluation	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (\$M, before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
Deloitte LLP	December 31, 2020	Canada	-	<b>\$1,489,449</b>	-	<b>\$1,489,449</b>

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Deloitte LLP  
700, 850 – 2nd Street S.W.  
Calgary, Alberta  
T2P 3P8

*(signed) "Andrew Botterill"*  
\_\_\_\_\_  
Andrew Botterill, P. Eng.  
Partner

Execution date: February 9, 2021

**SCHEDULE "B"**  
**REPORT OF MANAGEMENT AND DIRECTORS**  
**ON OIL AND GAS DISCLOSURE**

Management of Yangarra Resources Ltd. (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 which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, estimated using forecast prices and costs.

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 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, in the event of a proposal to change the independent qualified reserves evaluator, to inquire whether there had been disputes between the previous independent qualified reserves evaluator and management; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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; 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) "James Evaskevich"  
James Evaskevich  
President and CEO

(signed) "James Glessing"  
James Glessing  
CFO

(signed) "Robert Weir"  
Robert Weir  
Director

(signed) "Gordon Bowerman"  
Gordon Bowerman  
Director

February 9, 2021

**SCHEDULE "C"**  
**AUDIT COMMITTEE CHARTER**

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All of the Audit Committee members shall be independent and financially literate within the meaning of National Instrument 52-110 or its successor or replacement policy (the "**Instrument**") or as the case may be exempt from the requirements of sections 1.4 and 1.5 of the Instrument in accordance with the Instrument provisions.

Meaning of Financial Literacy — For the purposes of this Mandate, an individual is financially literate if he or she 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 complexity of the issues that can reasonably be expected to be raised by the issuer's financial statements.

The Audit Committee shall meet at least four times per year, on a quarterly basis, to fulfill its mandate.

The Audit Committee shall recommend to the Board of Directors:

- (a) the external auditor to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation; and
- (b) the compensation of the external auditor.

The Audit Committee is directly responsible for overseeing the work of the external auditor engaged for the purposes of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditor regarding financial reporting.

The Audit Committee shall pre-approve all non-audit services to be provided to the Corporation or its subsidiaries' entities by the Corporation's external auditor.

The Audit Committee shall review the Corporation's financial statements, MD&A and annual and interim profit or loss press release before the Corporation publicly discloses this information.

The Audit Committee must satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements, other than the public disclosure referred to in the paragraph above, and must periodically assess the adequacy of those procedures.

The Audit Committee must establish procedures for:

- (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal controls, or auditing matters; and
- (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

The Audit Committee shall review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.