ANNUAL INFORMATION FORM

for the year ended December 31, 2019

March 16, 2020

TABLE OF CONTENTS

ABBREVIATIONS

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	one barrel	Mcf	one thousand cubic feet
Bbl	barrels	Mcfe	one thousand cubic feet of natural gas equivalent on the basis of 6 Mcfe for 1 bbl of oil (unless otherwise indicated)
bbl/d	barrels per day	MMcf	one million cubic feet
Mbbl	thousand barrels	Bcf	one billion cubic feet
BOE	barrels of oil equivalent of natural gas on the basis of 1 BOE for 6 Mcf of natural gas (unless otherwise indicated)	Mcf/d	one thousand cubic feet per day
MBOE	one thousand barrels of oil equivalent	MMcf/d	one million cubic feet per day
MMBOE	one million barrels of oil equivalent	GJ	gigajoule
BOE/d	barrels of oil equivalent per day	GJs/d	gigajoules per day
NGL	natural gas liquids	Btu	British thermal unit
Stb	standard stock tank barrel	MMbtu	million British thermal units

BOEs or Mcfe may be misleading, particularly if used in isolation. A BOE or Mcfe conversion ratio of six Mcf to one 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. This conversion factor is an industry accepted norm and is not based on either energy content or current prices. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.

Other

AECO	Rockpoint Gas Storage Canada Ltd.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
m^3	cubic metres
$000's	thousands of dollars
WCS	Western Canadian Select, the standard reference for heavy blended crude, price paid at Hardisty, Alberta
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	thousand cubic metres ("**10^3m^3**")	0.0282
thousand cubic metres	Mcf	35.494
bbl	cubic metres ("**m^3**")	0.159
cubic metres	bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

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

"**BMEC**" means Black Mountain Energy Corporation, a corporation incorporated under the laws of Alberta which was amalgamated with Old Gear on May 1, 2010;

"**BMEC Acquisition**" means the offer of BMEC to purchase all of the issued and outstanding Class A common shares of Old Gear from the shareholders of Old Gear in exchange for 1.4 common shares of BMEC and 0.258125 non-voting preferred shares of BMEC for each Class A common share of Old Gear outstanding;

"**Board**" means the board of directors of the Corporation;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means common shares in the capital of Gear;

"**Convertible Debenture Indenture**" means the convertible debenture indenture dated November 30, 2015 between the Corporation and Computershare Trust Company of Canada governing the terms of the Convertible Debentures;

"**Convertible Debentures**" means the 4.00% convertible unsecured subordinated debentures due November 30, 2020 of Gear;

"**Corporation**" or "**Gear**" means Gear Energy Ltd., a corporation amalgamated under the laws of the Province of Alberta;

"**Credit Facilities**" means the $50 million credit facilities with a syndicate of lenders led by Alberta Treasury Branches entered into by Gear on July 27, 2016 concurrently with the completion of the Striker Arrangement, as amended and increased by a first amending agreement made as of November 30, 2016, a second amending agreement made as of May 25, 2017, a third amending agreement made as of May 4, 2018, a fourth amending agreement made as of September 18, 2018 increasing the borrowing base to $115 million concurrently with the completion of the Steppe Arrangement, and as amended and decreased to $90 million by a fifth amending agreement made as of May 23, 2019;

"**Gross**" means:

(a) in relation to an entity's interest in production and reserves, its "company gross reserves", which are such entity's working interest (operating and non-operating) before deduction of royalties and without including any royalty interest of such entity;

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

(c) in relation to properties, the total area of properties in which an entity has an interest;

"**NCIB**" has the meaning ascribed to it in the section "*General Development of the Business – Three Year History – Year Ended December 31, 2019*";

"**Net**" means:

(a) in relation to an entity's interest in production and reserves, such entity's interest (operating and non-operating) after deduction of royalties obligations, plus the entity's royalty interest in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating an entity's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which an entity has an interest multiplied by the working interest owned by it;

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* adopted by the Canadian Securities Administrators;

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations* adopted by the Canadian Securities Administrators;

"**Old Gear**" means Gear Energy Ltd., a corporation incorporated under the laws of Alberta which was amalgamated with BMEC on May 1, 2010;

"**OPEC**" means the Organization of the Petroleum Exporting Countries;

"**Options**" means options to purchase Common Shares granted under the share option plan of the Corporation;

"**Preferred Shares**" means preferred shares, issuable in series, in the capital of Gear;

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval, accessible at www.sedar.com;

"**Series 1 Preferred Shares**" means the authorized Series 1 preferred shares in the capital of Gear;

"**Sproule**" means Sproule Associates Limited, independent oil and natural gas reservoir engineers of Calgary, Alberta;

"**Sproule Report**" means the independent engineering evaluation of Gear's oil, natural gas liquids and natural gas interests prepared by Sproule effective December 31, 2019 and dated February 4, 2020;

"**Steppe**" means Steppe Resources Inc., a corporation incorporated under the laws of the Province of Alberta which was amalgamated with Gear on September 18, 2018;

"**Steppe Arrangement**" means the acquisition by Gear of all the issued and outstanding common shares of Steppe pursuant to a plan of arrangement under the ABCA whereby shareholders of Steppe received 0.1445 of a Common Share for each share of Steppe;

"**Steppe Petroleum**" means Steppe Petroleum Inc., a corporation incorporated under the laws of the Province of Alberta which was amalgamated with Gear on January 1, 2019;

"**Steppe (USA)**" means Steppe Petroleum (USA) Inc., a corporation incorporated under the laws of the State of Delaware, and a wholly-owned subsidiary of the Corporation as a result of the January 1, 2019 amalgamation between Gear and Steppe Petroleum;

"**Striker**" means Striker Exploration Corp. a corporation amalgamated under the laws of Alberta which was amalgamated with Gear on July 29, 2016;

"**Striker Arrangement**" means the acquisition by Gear of all the issued and outstanding common shares of Striker pursuant to a plan of arrangement under the ABCA whereby shareholders of Striker received 2.325 Common Shares for each share of Striker;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5^{th} Supp.), as amended, including the regulations; and

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

CONVENTIONS

Certain terms used herein are defined under the heading "*Certain Definitions*".

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2019.

READER ADVISORY REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, the financial and business prospects and financial outlook, Gear's strategy to attempt to enhance returns on its assets, Gear's strategy to achieve growth, Gear's expected acquisition criteria, reserve and production estimates, details of Gear's capital budget for 2020, expected exploration and development activities, expected timing for developing undeveloped reserves, drilling and re-completion plans, timing of drilling, re-completion and tie-in of wells, expected plans to test Gear's emergency response plan, expected abandonment and reclamation activities, expected future abandonment and reclamation obligations, productive capacity of wells, details of capital expenditure activity and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, price differentials, exchange rates, production expenses, transportation costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward-looking statements or forward-looking information (collectively, "**forward-looking statements**"). Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These forward-looking statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with public health risks including COVID-19, risks associated with volatility of commodity prices, oil and gas exploration, development, exploitation, production, changes to the Corporation's capital budget, marketing and transportation, loss of markets, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals, ability to access sufficient capital from internal and external sources, risks relating to the Corporation's ability to repay amounts outstanding under the Credit Facilities when, and if, required and the risk factors outlined under "*Risk Factors*" and elsewhere herein. The recovery and reserve estimates of the Corporation's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such forward-looking statements but which may prove to be incorrect. Although the Corporation believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because the Corporation can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this Annual Information Form, assumptions have been made regarding, among other things: future oil and natural gas prices; the Corporation's current capital budget for 2020; the Corporation's potential drilling locations and budget for 2020 if commodity prices change, upwards or downwards, in a material fashion; the general stability of the economic and political environment in which the Corporation operates; the impact of increasing competition; the timely receipt of any required regulatory approvals; the ability of the Corporation to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Corporation has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Corporation to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Corporation to secure adequate product transportation; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation operates; and the ability of the Corporation to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

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

CORPORATE STRUCTURE

Name, Address and Incorporation

Gear is a Canadian exploration and production company with heavy and light oil production in central Alberta, west central and southeast Saskatchewan and British Columbia.

Gear was incorporated on June 25, 2007 under the ABCA as "Black Mountain Energy Corporation". On January 29, 2010, BMEC acquired all of the issued and outstanding common shares of Old Gear pursuant to the BMEC Acquisition. BMEC and Old Gear amalgamated on May 1, 2010 and continued under the name "Gear Energy Ltd."

On June 3, 2010, Gear amended its articles to: (i) consolidate the Common Shares on the basis of one post-consolidation Common Share for every five pre-consolidation Common Shares; and (ii) to convert the then-issued and outstanding Series 1 Preferred Shares to Common Shares on the basis of one post-consolidation Common Share for every five pre-consolidation Series 1 Preferred Shares.

Gear was amalgamated under the provisions of the ABCA on September 21, 2011 with its wholly-owned subsidiary, Lift Resources Inc., and continued under the name "Gear Energy Ltd."

Pursuant to the Striker Arrangement, Gear was amalgamated with Striker on July 27, 2016, and continued under the name "Gear Energy Ltd."

Pursuant to the Steppe Arrangement, Gear was amalgamated with Steppe on September 18, 2018, and continued under the name "Gear Energy Ltd."

Gear was then amalgamated under the provisions of the ABCA on January 1, 2019 with its wholly-owned subsidiary, Steppe Petroleum, and continued under the name "Gear Energy Ltd." As a result, Steppe (USA), a corporation incorporated under the laws of the State of Delaware, U.S.A and formerly a direct and wholly-owned subsidiary of Steppe Petroleum, is now a direct and wholly-owned subsidiary of Gear. Other than Steppe (USA), Gear has no subsidiaries.

The head office of Gear is located at Suite 800, 205 – 5th Avenue S.W., Calgary, Alberta T2P 2V7 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The following is a summary of the significant events in the development of the Corporation's business over the last three completed financial years.

Year Ended December 31, 2017

On May 10, 2017 at the Corporation's annual meeting of shareholders, Messrs. Peter Verburg and Neil Roszell retired from the Board.

On May 25, 2017, the Corporation increased the borrowing base under the Credit Facilities to $55 million. In conjunction with the increase of the borrowing base, the revolving period was extended until May 31, 2018 and was extendible for 364 days with the consent of the lenders.

Total capital spending in 2017, including net acquisitions, was $49 million. The majority of these funds were spent to drill 34 gross (34 net) horizontal oil wells with a 97% success rate. The 2017 drilling program focused on multiple areas including Wildmere, Paradise Hill, Hoosier, Wilson Creek and Killam.

Year Ended December 31, 2018

On May 31, 2018, Ms. Bindu Wyma was appointed to the Board and to the Reserves Committee of the Board.

On May 4, 2018, the Corporation increased the borrowing base under the Credit Facilities to $75 million. In conjunction with the increase of the borrowing base, the revolving period was extended until May 30, 2019 and was extendible for 364 days with the consent of the lenders.

On September 18, 2018, Gear completed the Steppe Arrangement whereby the Corporation acquired all of the issued and outstanding common shares of Steppe pursuant to a plan of arrangement under the ABCA. Shareholders of Steppe received 0.1445 of a Common Share for each share of Steppe owned, resulting in the issuance of 21.9 million Common Shares by Gear. Gear also assumed Steppe's net debt of approximately $40.9 million, after taking into account Steppe's transaction costs.

Pursuant to the Steppe Arrangement, Steppe amalgamated with 2138359 Alberta Ltd., a wholly-owned subsidiary of Gear, and continued under the name "Steppe Resources Inc." Immediately following the amalgamation, Gear amalgamated with the newly formed Steppe Resources Inc., now a wholly-owned subsidiary of Gear, and continued under the name "Gear Energy Ltd."

Concurrent with the completion of the Steppe Arrangement, Gear entered into an amending agreement in respect of the Credit Facilities, providing for an increase in the borrowing base to $115 million. The next semi-annual borrowing base review of the Credit Facilities will occur on or about May 31, 2019. Steppe's senior secured credit facility was repaid in full and terminated in connection with the closing of the Steppe Arrangement.

Total capital spending in 2018, including net acquisitions, was $110 million. Aside from the Steppe Arrangement, the majority of these funds were spent to drill 26 gross (24 net) horizontal oil wells with a 96% success rate. The 2018 drilling program focused on multiple areas including Wildmere, Wilson Creek, Paradise Hill and Hoosier.

Year Ended December 31, 2019

On May 8, 2019, Mr. Raymond Cej retired from the Board.

On May 23, 2019, the Corporation reduced the borrowing base of the Credit Facilities from $115 million to $90 million. The Credit Facilities are currently comprised of a $70 million syndicated revolving term credit facility and a $20 million operating credit facility. In conjunction with the change of the borrowing base, the revolving period was extended until May 30, 2020 and was extendible for 364 days with the consent of the lenders. If the revolving period is not extended the maturity date of the Credit Facilities will be one year after the end of the revolving period.

On July 9, 2019, the Corporation announced that Mr. John O'Connell resigned from the Board and Mr. Scott Robinson was appointed to the Board.

On August 7, 2019, the Corporation announced that Mr. Kevin Olson retired from the Board and Messrs. Greg Bay and Wilson Wang were appointed to the Board.

On August 7, 2019, the Corporation announced its intention to proceed with a normal course issuer bid (the "**NCIB**") pursuant to which Gear would be able to repurchase for cancellation its Common Shares through the facilities of the TSX. In order to effect the NCIB, Gear was required to reduce its stated capital pursuant to the provisions of the ABCA. At a special meeting of Gear's shareholders held on September 20, 2019, the shareholders of the Corporation approved a special resolution to reduce the stated capital of the Common Shares by $150 million to $90 million. See "*Description of Capital Structure – Reduction in Stated Capital*".

The TSX approved the NCIB on September 23, 2019. The NCIB commenced on September 25, 2019 and will terminate on the earlier of: (i) the date on which Gear has acquired all Common Shares sought pursuant to the NCIB; or (ii) September 24, 2020, unless terminated earlier at the option of the Corporation upon prior notice being given to the TSX. Pursuant to the NCIB, Gear will be able to purchase for cancellation up to 10,954,673 Common Shares (approximately 5% of its then issued and outstanding Common Shares) for a one year period at prevailing market prices at the time of purchase. The total number of Common Shares Gear is permitted to purchase is subject to a daily purchase limit of 58,069 Common Shares (representing 25% of the average daily trading volume of 232,278 Common Shares on the TSX calculated for the six-month period ended

August 31, 2019); however, Gear may make one block purchase per calendar week which exceeds the daily purchase restrictions. The Common Shares purchased will be purchased by a registered broker through the facilities of the TSX and other alternative Canadian trading platforms at the time of such transaction. For the period ended December 31, 2019, 1.6 million Common Shares with an aggregate value of $0.7 million were repurchased pursuant to the NCIB.

On November 27, 2019, the Corporation completed its semi-annual borrowing base review and no further changes were made to the Credit Facilities. The next semi-annual borrowing base review of the Credit Facilities will occur on or about May 31, 2020.

Total capital spending in 2019, including net acquisitions, was $36.0 million. The majority of these funds were spent to drill 16 gross (16 net) oil wells with a 100% success rate**.** The 2019 drilling program focused on multiple areas including Wildmere, Maidstone, Tableland and Wilson Creek.

Recent Developments

Gear's original approved capital budget for 2020 was $50 million. Pursuant to that budget for 2020, 75% of the budgeted capital was intended to be dedicated to drilling on 26 locations (25.2 net), including five southeast Saskatchewan light oil wells, 17 Lloydminster area heavy crude oil wells and four (3.2 net) Central Alberta light and medium oil wells; 13% of budgeted capital was intended to be invested in continued waterflood expansions, recompletions, workovers and field facility projects; 7% of budgeted capital was intended to be invested in ongoing abandonment and reclamation activities; and the remaining 5% of budgeted capital was intended to be invested towards land, seismic and other corporate costs.

Subsequent to the release of that budget, global oil prices weakened materially as a result of the COVID-19 pandemic compounded by OPEC+, led by Saudi Arabia and Russia, failing to reach an agreement on constraining output, and a revised 2020 budget was approved with capital reduced to $13 million. $11 million of the expenditures were forecast to be completed by the end of the first quarter which included the drilling of nine wells within various medium and heavy oil assets. The remaining $2 million were forecasted for non-discretionary spending required through to the end of the year. See "*Description of the Business – Business Plan and Corporate Strategy*".

For the period from January 1, 2020 to March 14, 2020, 1.1 million Common Shares with an aggregate value of $0.5 million were repurchased pursuant to the NCIB.

Significant Acquisitions

There were no significant acquisitions completed by the Corporation during its most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

DESCRIPTION OF THE BUSINESS

General

Gear is a Calgary, Alberta based junior Canadian crude oil and natural gas exploration and production company. All of the Corporation's oil and gas properties are located in Alberta, British Columbia and Saskatchewan. The Corporation currently has core holdings in central Alberta and west central and southeast Saskatchewan. The Corporation has a significant land position in Alberta and Saskatchewan and intends to continue to evaluate additional oil and gas assets in Alberta and Saskatchewan.

Business Plan and Corporate Strategy

Gear's strategy is to provide long term production and cash flow growth on a per debt adjusted share basis as a low cost oil and gas operator. The Corporation's business plan contemplates that the Corporation will pursue exploration, development and exploitation drilling, complemented with property or corporate acquisitions exhibiting synergies in land, facilities, production and operating efficiencies.

Gear plans to achieve this growth by pursuing assets with the following characteristics:

- Geographically focused
- Definable resource base with low risk production
- Repeatable projects that are statistically economic
- Horizontally amenable producing horizons
- Easy surface access and existing infrastructure
- High operatorship percentage

See "*Risk Factors*".

Gear's strategy to attempt to enhance returns on its assets is by:

- Drilling and developing on controlled lands
- Focusing on operational and cost efficiencies
- Continually improving operations through innovation and imitation
- Adopting and refining advanced drilling and completing techniques
- Pursuing strategic acquisitions with significant potential synergies

In reviewing potential drilling or acquisition opportunities, Gear gives consideration to a variety of criteria, including: (i) the capital required to secure or evaluate the investment opportunity; (ii) if successful, the potential return on the project; (iii) the likelihood of success; (iv) the risk of return versus cost of capital; (v) the strategic benefits to Gear; and (vi) Gear's ability to operate a project.

The Board may, in its discretion, approve asset or corporate acquisitions or investments, including those acquisition or investments that do not conform to the guidelines discussed above based upon the Board's consideration of, among other things, the qualitative aspects of the subject properties, including risk profile, technical upside, productive life and asset quality.

In December of 2019, the Board approved a $50 million capital budget for 2020, targeting further growth in funds from operations through a strategic balance between production stability, continued improvement of its strong balance sheet and additional purchases of its Common Shares under the NCIB. At the time, Gear expected its 2020 capital program to be financed with funds from operations. Following a dramatic period of oil price weakness resulting from the COVID-19 pandemic compounded by OPEC+, led by Saudi Arabia and Russia, failing to reach an agreement on constraining output, the Board approved a revised budget in March of 2020 with a capital program reduced to $13 million.

The amount of capital the Corporation will expend for its 2020 exploration and development program and the nature of its expenditures may vary materially based on commodity prices, market access, transportation constraints, other industry conditions and the Corporation's drilling results as the year progresses. Access to additional capital may spur an expansion of the program; however, any significant reduction in commodity prices, any unexpected reduction in Gear's access to capital or any constraints on Gear's ability to transport and market its production may lead to a reduction in the Corporation's 2020 exploration and development program. Although Gear's management remains committed to the above strategy, the current instability and uncertainty in the Canadian crude oil and natural gas industry and the challenges crude oil and natural gas producers continue to face with respect to the availability of funds and access to markets may impact Gear's ability to continue to pursue its business strategy. See "*Industry Conditions*" and "*Risk Factors*" for further details.

Specialized Skill and Knowledge

Gear believes that its team has all of the key components to successfully implement its business plan: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; extensive experience in crude oil and natural gas exploration and development in Western Canada; and an entrepreneurial spirit that allows Gear to effectively identify, evaluate and execute on value-added initiatives. See "*Directors and Executive Officers*".

Competitive Conditions

The crude oil and natural gas industry is intensely competitive in all its phases. Companies operating in the upstream petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration and development, commodity prices, foreign exchange rates, interest rates, environmental damages, market access and the current weakness impacting the crude oil and natural gas industry as a whole. See "*Risk Factors – Competition*".

Gear expects the intense level of competition to continue in the future. Gear competes with a substantial number of other entities, certain of which have greater technical or financial resources particularly when it comes to acquiring reserves, crude oil and natural gas mineral rights, skilled industry personnel, access to end user markets and capital to finance their activities. With the maturing nature of the Western Canadian Sedimentary Basin, access to new prospects is becoming more competitive and complex and Gear's ability to execute its business plan of growing its crude oil and natural gas reserves and cash flow will depend not only on the Corporation's ability to exploit and develop existing properties but also its ability to identify and acquire additional properties or prospects for exploratory and development drilling. Gear believes that its competitive position is equivalent to that of other crude oil and natural gas issuers of similar size and at a similar stage of development.

Cyclical Nature of Business

In general, the energy business is cyclical in nature and heavily dependent on macro-economic cycles. In periods of economic expansion and growth the demand for energy increases as economies build inventory and productive capacity. Generally, in periods of economic contraction or recession, the rate of growth in energy demand declines. These macroeconomic cycles often impact global, North American and local prices for commodities, particularly crude oil and natural gas prices. In addition, the actions of OPEC and other oil producing countries and other factors impacting supply of oil will impact the price of oil. See "*Risk Factors – Weakness and Volatility in the crude oil and natural gas Industry*".

Demand for heavy crude oil begins to increase in the spring time and peaks in the summer months as heavy crude oil is often the base feed stock which supply refineries that make end products such as transportation fuels, heating oils, and asphalt for road paving. During the fall, refiners switch from making gasoline for summer driving season and asphalt for paving season and enter turn around season creating temporary lower demand for heavy crudes while these refineries undergo maintenance and repairs. Demand picks up again through the winter with a focus on making heating fuels until the spring comes and refiners again switch to focus on building gasoline stocks for the summer season. Demand for light oil can also vary throughout the year, although not usually with the same volatility as heavy crude oil.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, 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 natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain.

In anticipation of the operational delays associated with "spring break up", the Corporation takes certain steps to mitigate interruption to its activities including, scheduling drilling and completion activities to be completed before the spring break up season, setting up extra batteries to collect the crude oil and natural gas produced during such time, servicing pipelines and facilities to ensure they are in working order in the event access is limited. Through the duration of spring break up, drilling and exploratory activities slow and the Corporation's production which is not otherwise tied-in may be shut in temporarily if access is limited.

In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury as a result of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity (including temporary production shut-ins), damage to the Corporation's equipment or injury to its personnel.

See "*Risk Factors – Seasonality*".

Environmental Considerations and Protection

The Corporation is required to comply with various federal, provincial and municipal laws related to climate change and protection of the environment. Compliance with such laws affect a variety of aspects of the Corporation's operations including, among others, abandonment and reclamation of wells, facilities and related infrastructure, flaring and venting of natural gas, water usage and disposal, greenhouse gas ("**GHG**") emissions and clean-ups of spills.

In addition to compliance with the abandonment and reclamation obligations under provincial legislation in Alberta, British Columbia and Saskatchewan, Gear believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs. As a result, Gear allocates a portion of its annual capital budget to such activities. During 2019, Gear invested approximately $2.9 million in the abandonment and reclamation of wells and related facilities and infrastructure. For further information relating to the abandonment and reclamation programs in Alberta, British Columbia and Saskatchewan and see "*Industry Conditions - Regulatory Authorities and Environmental Regulation – Liability Management Rating Program*".

The federal government and certain provincial governments have enacted legislation aimed at discouraging the use of fossil fuels in an effort to decrease GHG emissions. Over the long-term, laws designed to curb the use of fossil fuels in Canada and other countries could have an impact on the demand for fossil fuels and have a negative impact on the price of oil and natural gas, which would have an effect on the Corporation's financial results and ultimately the sustainability of the Corporation's business model. In the short-term, carbon taxes and other legislative measures designed to curb GHG emissions may adversely affect Gear's financial results as such taxes increase the costs of fuels used to operate Gear's machinery and vehicles; however, as Gear does not have any facilities that exceed current emissions thresholds that would subject Gear to more onerous requirements, the short, medium and long-term impacts of carbon taxes and similar measures are not expected to have a material effect on the Corporation's financial results. As at the date hereof, Gear's current emission levels are not subject to any climate change regulations. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Climate Change*" and "*Risk Factors – Carbon Pricing Risk*".

Partially in response to legislative measures aimed at curbing flaring and venting of natural gas and the associated release of methane and other GHGs into the atmosphere, Gear strives to collect and market gas in order to decrease the volume that is flared or vented. In 2019, Gear spent approximately $1.3 million on transportation and other infrastructure to allow gas from its production to be collected and brought to market rather than such gas being vented or flared. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Climate Change*" and "*Risk Factors – Carbon Pricing Risk*".

Gear undertakes waterflooding and fracing activities as part of its operations. The majority of the water is reused and recycled in the waterflood and completion activities; therefore, there is immaterial financial costs associated with disposal. Although minimal, Gear works to ensure the safe disposal of the fluids to avoid the contamination of ground water. In addition to the costs associated to waterflooding/fracing activities, Gear may from time to time have limited access to sufficient volumes of fluids or there may be restrictions imposed on such activities in the areas in which it operates which would have a negative effect on Gear's production volumes and revenues. See "*Risk Factors – Disposal of Fluids Used in Operations*" and "*Risk Factors – Waterflood*".

Although Gear operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety, occasionally fluid spills and other incidents threatening the environment may occur. The costs of cleaning up such spills could negatively affect the Corporation's financial and operating results as the Corporation has to incur costs and utilize resources in cleaning up such spills. In 2019, the Corporation experienced no material spills.

Health, Safety, Environmental and Social Policies

Gear's management, employees and all contractors are responsible and accountable for the overall health, safety and environmental program of the Corporation. Gear operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

Gear maintains a safe and environmentally responsible workplace and provides training, equipment and procedures to all individuals in adhering to its policies. It also solicits and takes into consideration input from neighbors, communities and other stakeholders in regard to protecting people and the environment.

At the field level, Gear has a corporate Environment Management System which is continuously updated and meets the regulatory guidelines. Procedures are put in place to ensure that the utmost care is taken in the day-to-day management of Gear crude oil and natural gas properties with an emphasis on incident prevention. In addition, Gear requires each of its field workers to have completed industry standard courses.

The Corporation also has Emergency Response Plans ("**ERPs**") which are prepared in accordance with applicable regulations. The ERPs are designed to provide the policies, practices and procedures to be implemented in the event of an emergency situation that arises at or as a result of Gear's operations, including but not limited to: a serious injury or fatality, fire or explosion, uncontrolled or hazardous product release and oil or hazardous chemical spill. The purpose of the ERPs is to protect the health, safety and welfare of the public and workers and minimize the potential adverse environmental effects. Gear held a functional tabletop ERP exercise in Alberta in 2019 to test our understanding and effectiveness in the case of an actual emergency. Gear holds exercises annually to ensure that our staff and executives are ready should the need arise. Management intends to test the ERPs in 2020 to ensure their effectiveness and procedures are revised to ensure the Corporation is adhering to the highest industry standards.

The Board receives a report from management at each quarterly Board meeting outlining any environmental or safety incidents that occurred or areas of concern that have arisen since the last quarterly Board meeting. More significant incidents, if any, are discussed in greater detail and management and the Board consider whether any changes should be implemented as a result of the incident.

Employees

As at December 31, 2019, Gear had 33 employees with 22 staff in the Calgary office and 11 employees located in Gear's operating areas in Alberta and Saskatchewan. Gear also has a number of contract operators in the field.

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 February 4, 2020. The effective date of the Statement is December 31, 2019 and the preparation date of the Statement is February 4, 2020.

Disclosure of Reserves Data

The Corporation engaged Sproule to provide an evaluation of the Corporation's proved and proved plus probable reserves as at December 31, 2019. The reserves data set forth below (the "**Reserves Data**") is based upon the Sproule Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas proved and probable reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards and the reserve definitions contained in the COGE Handbook and NI 51-101. The Reserves Committee of the Board has reviewed and approved the Sproule Report and this statement. The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

All of the Corporation's reserves are in Canada and, specifically, in the Provinces of Alberta, British Columbia and Saskatchewan.

All evaluations of future net production revenue set forth in the tables below are based on forecast prices and costs and are after direct lifting costs and future capital investments. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained, and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF CORPORATION OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (MMcf)	CONVENTIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	TOTAL Gross (MBOE)	TOTAL Net (MBOE)
Proved Developed										
Producing	3,913	3,531	3,348	3,084	6,827	6,056	462	366	8,861	7,991
Non-Producing	-	-	93	86	-	-	-	-	93	86
Proved Undeveloped	2,970	2,720	3,465	3,199	3,713	3,379	242	210	7,295	6,692
Total Proved	6,882	6,251	6,906	6,369	10,541	9,435	704	576	16,249	14,769
Probable	4,360	3,906	5,800	5,184	4,660	4,209	329	270	11,265	10,060
Total Proved plus Probable	11,242	10,157	12,705	11,553	15,201	13,644	1,033	846	27,515	24,829

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/BOE)
Proved Developed											
Producing	150,050	170,449	162,581	150,606	139,370	150,050	170,449	162,581	150,606	139,370	20.34
Non-Producing	2,869	2,461	2,137	1,875	1,660	2,869	2,461	2,137	1,875	1,660	24.82
Proved Undeveloped	140,908	103,341	76,088	56,982	43,251	140,908	103,341	76,088	56,982	43,251	11.37
Total Proved	293,826	276,252	240,807	209,463	184,281	293,826	276,252	240,807	209,463	184,281	16.30
Probable	330,848	239,250	182,584	144,950	118,405	255,288	181,589	136,963	107,851	87,588	18.15
Total Proved plus Probable	624,674	515,502	423,390	354,413	302,686	549,114	457,841	377,769	317,314	271,869	17.05

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS[1] (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	1,017,169	99,120	344,596	152,046	127,581	293,826	-	293,826
Total Proved plus Probable	1,784,050	186,893	573,822	260,936	137,725	624,674	75,560	549,114

Note:

(1) Reflects estimated abandonment and reclamation for all existing wells (both active and inactive), undeveloped locations (booked by Sproule in the Sproule Report), and facilities. See "*Additional Information Relating to Reserves Data"*.

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
Proved Reserves	Light and Medium Crude Oil[1]	125,326	$15.79/boe
	Heavy Crude Oil[1]	115,024	$17.98/boe
	Conventional Natural Gas[2]	456	$1.05/boe
Proved Plus Probable Reserves	Light Crude Oil and Medium Crude Oil[1]	193,864	$15.29/boe
	Heavy Crude Oil[1]	228,650	$19.71/boe
	Conventional Natural Gas[2]	876	$1.60/boe

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Columns may not add due to rounding.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth in the "*Certain Definitions*" and below.

3. Levels of Certainty for Reported Reserves:

The qualitative certainty levels referred to below are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

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

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

4. Forecast Costs and Price Assumptions

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were an average of forecast prices and costs published by Sproule, GLJ Petroleum Consultants Ltd., and McDaniel & Associates Consultants Ltd. as at December 31, 2019, which are as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL							
	WTI Cushing Oklahoma	Edmonton Oil Price 40° API	WCS Oil Price	Natural Gas AB Plant Gate Spot Gas Price	Pentanes Plus Edmonton	Butanes Price Edmonton	Inflation Rates[(1)]	Exchange Rate[(2)]
Year	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/MMBtu)	($Cdn/bbl)	($Cdn/bbl)	%/Year	($US/$Cdn)
Forecast								
2020	61.00	72.64	57.57	2.04	76.83	42.10	0.0	0.760
2021	63.75	76.06	62.35	2.32	79.82	47.03	1.67	0.770
2022	66.18	78.35	64.33	2.62	82.30	50.66	2.00	0.785
2023	67.91	80.71	66.23	2.71	84.72	52.21	2.00	0.785
2024	69.48	82.64	67.97	2.81	86.71	53.48	2.00	0.785
2025	71.07	84.60	69.72	2.89	88.73	54.77	2.00	0.785
2026	72.68	86.57	71.49	2.96	90.77	56.07	2.00	0.785
2027	74.24	88.49	73.20	3.03	92.76	57.32	2.00	0.785
2028	75.73	90.31	74.80	3.09	94.65	58.50	2.00	0.785
2029	77.24	92.17	76.43	3.16	96.57	59.71	2.00	0.785
2030+	Escalated oil, gas and product prices at 2% per year thereafter							

Notes:

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

Weighted average historical prices realized, before transportation and financial derivative contracts, by the Corporation for the year ended December 31, 2019 were $1.63/Mcf for natural gas, $66.69/bbl for light and medium oil, $53.87/bbl for heavy crude oil and $22.26/bbl for NGLs.

5. Sproule's evaluation this year as a result of changes to the COGE Handbook reflects the full estimated abandonment and reclamation for all existing wells (both active and inactive), undeveloped locations (booked by Sproule in the Sproule Report), and facilities regardless of whether such entities had any attributed reserves. Previous to this year's evaluation, well abandonment and lease reclamation costs had only been included for wells (both existing and undeveloped locations) that had been attributed reserves but additional abandonment and lease reclamation costs associated with existing wells with no attributed reserves and facility abandonment and reclamation expenses were not included in the analysis.

6. The forecast price and cost assumptions assume the continuance of current laws and regulations.

7. The extent and character of all factual data supplied to Sproule were accepted by Sproule as represented. No field inspection was conducted.

8. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

Reconciliations of Changes in Gross Reserves

RECONCILIATION OF CORPORATION GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2018[(1)]	7,207	4,265	11,472	7,282	6,467	13,749	658	332	990
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	40	39	79	782	544	1,326	8	7	15
Infill Drilling	205	454	660	-	-	-	18	9	27
Improved Recovery	62	(8)	54	-	13	13	8	2	10
Technical Revisions	400	(466)	(66)	380	(1,192)	(812)	110	(21)	89
Acquisitions	12	33	45	-	-	-	1	4	5
Dispositions	(12)	(3)	(15)	-	-	-	(1)	-	(1)
Economic Factors	(319)	47	(271)	(54)	(32)	(86)	(12)	(4)	(16)
Production	(714)	-	(714)	(1,484)	-	(1,484)	(86)	-	(86)
December 31, 2019[(2)]	6,882	4,360	11,242	6,906	5,800	12,705	705	329	1,033

	CONVENTIONAL NATURAL GAS			TOTAL		
FACTORS	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MBOE)	Gross Probable (MBOE)	Gross Proved Plus Probable (MBOE)
December 31, 2018[(1)]	11,918	5,044	16,962	17,134	11,904	29,037
Discoveries	-	-	-	-	-	-
Extensions	150	143	294	856	614	1,469
Infill Drilling	223	110	332	261	482	742
Improved Recovery	145	(80)	65	94	(7)	87

Technical Revisions	47	(402)	(355)	898	(1,746)	(848)
Acquisitions	11	37	48	15	43	58
Dispositions	(7)	(2)	(9)	(14)	(4)	(18)
Economic Factors	(395)	(189)	(584)	(450)	(20)	(471)
Production	(1,552)	-	(1,552)	(2,543)	-	(2,543)
December 31, 2019(2)	10,540	4,661	15,201	16,249	11,265	27,515

Notes:

(1) The opening balance as at December 31, 2018 was derived from an independent engineering evaluation of Gear's oil, natural gas liquids and natural gas interests prepared by Sproule effective December 31, 2018 and dated February 12, 2019.
(2) Columns may not add due to rounding.

Both proved and proved plus probable reserves under economic factors were negatively impacted by a weaker 2019 year end evaluator average price deck compared to the evaluator average price deck used for the opening balance.

The primary contributor to the negative technical revisions for the proved plus probable reserves was base performance issues in several legacy heavy oil properties, continued conservatism on the view of future production profiles for both developed and undeveloped locations, and finally the removal of drill locations on expired mineral acreage in heavy oil and Saskatchewan light oil.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the remaining proved undeveloped reserves and the remaining probable undeveloped reserves, each by product type, attributed to Gear's assets for the years ended December 31, 2019, 2018 and 2017.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2017	65	1,448	785	3,032	320	5,931	57	224	960	5,693
2018	2,063	3,268	528	3,175	829	3,779	50	191	2,779	7,264
2019	145	2,970	368	3,465	115	3,713	9	242	541	7,295

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2017	25	1,310	1,415	4,766	170	3,505	30	231	1,498	6,891
2018	2,227	2,972	1,045	4,541	621	2,330	32	146	3,408	8,047
2019	445	2,923	425	4,178	132	2,279	8	156	900	7,637

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.

In general, once proved and/or probable reserves are identified, they are included in Gear's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two to three years; however, these locations will continue to be re-evaluated to assess their relative economic merits when compared to other projects available to the Corporation. Undeveloped reserves planned to be developed beyond two to three years are scheduled in that manner due to various factors including access to capital, limitations on egress and pricing uncertainty. A number of factors that could result in delayed or cancelled development are as follows:

- development of a superior opportunity inventory to select from;
- changing economic conditions (due to pricing, royalties, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

See "*Other Oil and Gas Information – Principal Properties*", "*Additional Information Relating to Reserves Data – Future Development Costs*" and "*Other Oil and Gas Information – Capital Expenditures*" for a description of the Corporation's exploration and development plans and expenditures.

Significant Factors or Uncertainties

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

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs to produce and sell any material portion of its reserves. Where required, capital to construct facilities and pipelines necessary to deliver the forecasted products to market has been deducted from the estimates of cash flows used to calculate future net revenue. The Corporation has not entered into any contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized except for those contractual obligations described under the heading "*Other Oil and Gas Information – Forward Contracts and Marketing*".

The Corporation does not anticipate any unusually high abandonment or reclamation costs. Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Gear's audited financial statements for the year ended December 31, 2019 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com

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:

	Forecast Capital Costs (M$)	
Year	Proved Reserves	Proved Plus Probable Reserves
2020	29,480	51,980
2021	51,219	79,114
2022	35,776	60,298
2023	25,051	32,618
2024	10,519	16,302
Thereafter	-	20,623
Total Undiscounted	152,046	260,936

On an ongoing basis, Gear will use internally generated funds from operations, debt and new equity issues if available on favourable terms to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Corporation.

If funds from operations are other than projected, capital expenditures may be adjusted. In addition, depending on a number of factors including commodity prices, industry conditions and the Corporation's financial and operating results, debt or equity financing may not be available, which could also result in adjustments to the capital program as required. On March 11, 2020, the Corporation decided to reduce its 2020 capital program from $50 million to $13 million in order to manage cash. Those decisions were made in light of global reaction to the spread of COVID-19 and the resultant reduction in oil demand, compounded by OPEC+, led by Saudi Arabia and Russia, failing to reach an agreement on constraining output in face of lower global demand to support global oil prices and the stated intention of certain OPEC member countries to discount future deliveries and increase crude oil supply into the market.

Other Oil and Gas Information

Principal Properties

The Corporation is engaged in the exploration for and development and production of crude oil and natural gas in Western Canada. All of the Corporation's current operations are in the Provinces of Alberta and Saskatchewan, with some minor operations in the Province of British Columbia.

The following is a description of the Corporation's oil and natural gas properties as at the date hereof, unless otherwise stated. The reserve amounts stated are gross reserves, as at December 31, 2019 based on forecast costs and prices as evaluated in the Sproule Report (see "*Reserves Data*"). The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. The production values are all stated on a company interest basis, which includes Gear's royalty interests but does not deduct for royalties payable by Gear.

Celtic/Paradise Hill, Saskatchewan

The Celtic/Paradise Hill property was acquired as primarily undeveloped non-producing land starting in March 2014 and is located within Township 52, and Ranges 23 and 24 W3 and is approximately 40 kilometres northeast of Lloydminster Alberta. It is currently comprised of approximately 7,700 gross (7,500 net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Celtic/Paradise Hill is characterized by unconsolidated Upper Mannville group clastic reservoirs with depths ranging from 500 meters to 650 meters. While the McLaren formation has been the most exploited interval, Sparky and Waseca also hold potential as future development targets on Gear acreage.

Consistent with Gear's other heavy crude oil sites, each one to four well pad is equipped to operate independently and as such, the risk of a single event culminating into a material production loss is mitigated. Solution gas is gathered through a pipeline system and is used to heat production tanks. All oil production is tank treated to produce sales quality oil before being trucked to sales points. In 2014 Gear successfully drilled the first two gross (2 net) half section lined horizontal McLaren oil wells into the area. In 2015, a further three gross (3 net) horizontal wells were drilled. In 2016, Gear drilled an additional eight gross (8 net) horizontal McLaren oil wells. In 2017, Gear drilled fifteen gross (15 net) horizontal McLaren oil wells. In 2018, Gear drilled ten gross (10 net) horizontal McLaren oil wells. In 2019, Gear did not drill any wells in the area. The revised plan for 2020 includes the drilling of five gross (5 net) horizontal McLaren oil wells in the Celtic/Paradise Hill area. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 4,355 Mbbls of heavy crude oil at December 31, 2019 within the Celtic area.

The average production from the area for in 2019 was 1,796 BOE/d all of which consisted of heavy crude oil.

Wildmere Area, Alberta

The Wildmere field is located within Townships 47, 48 and 49, and Ranges 3, 4, 5 and 6W4, is approximately 200 kilometres southeast of Edmonton, Alberta. The property consists of approximately 27,000 gross (25,000 net) acres of lands with no material expiries as the majority of the lands have been continued pursuant to the applicable tenure regulations.

The Wildmere area is a heavy crude oil area characterized by unconsolidated Upper Mannville group clastic reservoirs with depths ranging from 600 meters to 700 meters. While the Lloydminster and Cummings formations have been the most exploited intervals, the General Petroleum, Colony and Sparky formations have also proven to be successful development targets for heavy crude oil on Gear acreage.

Each of Gear's Wildmere heavy crude oil sites is the surface location for one to four wells. Every pad is equipped to operate independently and, as such, the risk of a single event resulting in a material production loss is mitigated. Solution gas is pipeline connected through most of the field allowing wells to share gas for tank heating, to sell gas, or to deliver purchased gas if desired in order to offset propane otherwise used for tank heating. All Wildmere oil production is tank treated to produce sales quality oil before being trucked to sales points.

In 2016, Gear drilled three gross (3 net) quad-lateral un-lined horizontal wells in the Cummings at Wildmere. The original 2016 budget included plans to drill eleven multi-lateral horizontal Wildmere wells into the Cummings formation; however, that plan was put on hold due to poor oil prices. In 2017, Gear drilled five gross (5 net) multi-lateral un-lined horizontal wells in the Cummings at Wildmere. During 2017, six gross (6 net) dual-lateral un-lined horizontal wells targeting the GP formation were also drilled in Wildmere. In 2018, Gear drilled five gross (5 net) multi-lateral un-lined horizontal heavy crude oil wells in the Cummings and the Sparky formations. In 2019, Gear drilled eight gross (8 net) multilateral un-lined horizontal heavy crude oil wells in the GP and Sparky formations. The revised plan for 2020 has no budgeted drilling in the Wildmere area. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 3,647 Mbbls of heavy crude oil and 0.3 Bcf of natural gas as at December 31, 2019 within the Wildmere area. The average production from the area in 2019 was 1,360 BOE/d, which consisted of 1,301 bbls/d of heavy crude oil and 356 mcf/d of conventional natural gas.

Wilson Creek, Alberta

The Wilson Creek property was acquired in July 2016 pursuant to the Striker Arrangement and is located primarily within Townships 42 and 43, and Ranges 4 and 5 W5 in Central Alberta. The primary target zone is the regional Basal Belly River consolidated sandstone formation, which is a light oil pool that requires hydraulic fracturing. It is comprised of approximately

54,000 gross (42,000 net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Wilson Creek development is primarily characterized by the Basal Belly River reservoir with depth of approximately 1,300 meters. The light oil in the area is processed partially at single well batteries and partially with individual wells flow-lined to central facilities. In both cases, the resulting clean oil is trucked to the various sales points. The associated gas from Wilson Creek is gathered through third party infrastructure and sold to various parties.

In 2016 following completion of the Striker Arrangement, Gear drilled 2 gross wells (2 net) full section horizontal light oil wells into the Basal Belly River, one of which was completed in late 2016 and the other which was completed in early 2017. In 2017, Gear drilled three gross wells (2.8 net) full section horizontal light oil wells into the Basal Belly River. In 2018, Gear drilled seven gross (4.9 net) full section or extended reach light oil horizontal light oil wells. In 2019, Gear drilled one gross (1 net) horizontal light oil well in the Wilson Creek area. The revised plan for 2020 has no budgeted drilling in the area. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 3,841 Mbbls of light crude oil and NGLs and 6.3 Bcf of natural gas as at December 31, 2019 within Wilson Creek.

The average production from the area in 2019 was 1,034 BOE/d, which consisted of 584 bbls/d of heavy crude oil, 1,578 mcf/d of conventional natural gas and 187 bbls/d of natural gas liquids.

Tableland, Saskatchewan

The Tableland property was acquired in September 2018 pursuant to the Steppe Arrangement and is located primarily within Townships 1 and 2, and Ranges 10 and 11 W2, approximately 30 kilometers southwest of Estevan in Southeast Saskatchewan. It is comprised of approximately 35,000 gross (34,000 net) acres of land. There are no material expiries expected as the majority of lands have been continued pursuant to the applicable tenure regulations.

Tableland development is predominately focused on the Three Forks/Torquay formation, with minor production from the Bakken and Ratcliffe formations. The reservoir depths range from 1,400 to 1,700 meters. The sweet, light oil in the area is transported via pipe and truck to be processed at two Gear-owned central facilities. Sales oil is then trucked from those facilities to various sales points. The associated gas from the Tableland production is currently flared, although various options for conservation are being evaluated.

The acquisition of the Tableland property provides Gear with an opportunity to utilize its fractured drilling expertise developed in Wilson Creek, Alberta in the Torquay formation. The Tableland acquisition also provides Gear with an opportunity to potentially exploit the Ratcliffe and Bakken formations using multi-lateral, un-lined horizontal drilling techniques, similar to those employed successfully by the Corporation throughout its heavy crude oil portfolio. In 2019, Gear drilled five gross (5 net) two mile horizontal light oil wells in the Tableland area. The revised plan for 2020 has no budgeted drilling in the Tableland area. See "*Description of the Business – Business Plan and Corporate Strategy*".

A pipeline owned by Gear runs from the Tableland property in Saskatchewan to Divide County, North Dakota. Although the pipeline was initially built by Steppe to transport natural gas from Tableland to the United States for the sale of such natural gas, no substances have been transported through the pipeline since February 1, 2016.

The Sproule Report assigns total proved plus probable reserves of 5,661 Mbbls of light crude oil and NGLs as at December 31, 2019 within Tableland.

The average production from the area for in 2019 was 905 BOE/d all of which consisted of light and medium crude oil.

Other Areas

The Corporation held interests in a number of wells and lands in other portions of Alberta, British Columbia and Saskatchewan at December 31, 2019. In 2017, Gear drilled three heavy crude oil wells in Hoosier, Saskatchewan, and two medium oil wells in Killam, Alberta. In 2018, Gear drilled two heavy crude oil wells in Hoosier, Saskatchewan, one heavy crude oil well in Lindbergh, Alberta and one heavy crude oil well in Maidstone, Saskatchewan. In 2019, Gear drilled two gross (2 net) wells in the Maidstone area. The plan for 2020 was revised to include only wells that had already been drilled in the first quarter of 2020, including: two gross (2 net) multilateral un-lined horizontal heavy crude oil wells in the Lindbergh area, one gross (1 net) multilateral un-lined horizontal medium crude oil well in the Provost area and one gross (1 net) horizontal medium oil well in the Killam area. The Corporation has also allocated a small amount of capital in its budget for 2020 to continue to expand and optimize waterflood activities in the Killam area. See "*Description of the Business – Business Plan and Corporate Strategy*".

The Sproule Report assigns total proved plus probable reserves of 7,478 Mbbls of light, medium and heavy crude oil and NGLs and 8.6 Bcf of natural gas as at December 31, 2019 within these other areas.

The average production from these areas in 2019 was 1,867 BOE/d, which consisted of 474 bbls/d, 956 bbls/d of heavy crude oil, 2,318 mcf/d of conventional natural gas and 51 bbls/d of natural gas liquids.

Oil and Gas Wells

The following table sets forth the number and status of crude oil and natural gas wells in which the Corporation had a working interest as at December 31, 2019.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	312	251	592	540	406	61	204	153
British Columbia	-	-	-	-	-	-	8	6
Saskatchewan	151	150	175	148	2	1	49	43
Total	463	401	767	688	408	62	261	202

Note:

(1) This table does not include water source wells, injection wells, abandoned wells or wells which have never produced. Producing wells are based on public data status.

Land Holdings Including Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2019.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	143,715	113,228	84,693	74,428	228,408	187,656
British Columbia	10,550	4,330	6,005	3,320	16,555	7,650
Saskatchewan	56,513	52,158	36,243	35,838	92,756	87,996
Total	210,778	169,716	126,941	113,586	337,719	283,302

Gear calculates both its gross and net acres on a per lease basis. Undeveloped lands are calculated by adding the surface area acreage covered by the leases or agreements or portions of the leases or agreements without producing or potentially producing wells. In certain limited circumstances where the Corporation has rights in different formations under the same surface area pursuant to different leases or agreements, we have included the acreage with respect to all such leases or agreements. There are no significant factors or uncertainties associated with the undeveloped land.

Gear has approximately 19,500 net acres of its undeveloped land holdings that may expire by December 31, 2020, a portion of which may be continued pursuant to applicable tenure regulations. Gear plans to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

Most of Gear's crude oil and natural gas production is sold to major marketers on prearranged terms with indexing to published spot pricing. In a typical month, Gear splits the sale of its crude oil between several purchasers. These crude oil purchasers then ship Gear's crude oil via both pipeline and rail as title transfers at either pipeline or railway terminals. Gear does not set targets on the amount of crude oil to be sold into railway terminals; rather, it directs its oil sales to the highest received price net of transportation. Gear's established method of mitigating counter party risk is to deal with counterparties with strong credit ratings and to accept pre-payment on oil deliveries from smaller purchasers or those with less established credit ratings, if applicable.

The contract term is generally a 30-day evergreen in the case of pipeline connected crude oil buyers and up to one year for natural gas and natural gas liquids. For crude oil purchaser contracts at rail terminals, Gear generally enters into volume-based purchase contracts with 1 to 12 month terms. None of Gear's purchase agreements currently contain material non-performance penalties.

Gear may periodically hedge the price of a portion of its crude oil and natural gas production. The Corporation has no firm gas transportation contracts

A summary of contracts outstanding, as at December 31, 2019, in respect of the hedging activities is included in Note 12 to Gear's audited financial statements for the year ended December 31, 2019, which are available on SEDAR at www.sedar.com.

Tax Horizon

Based on current forward commodity prices, the Corporation does not expect to pay current income tax for the 2020 fiscal year. Gear does not expect to pay income tax in the next 5 years. There are multiple factors which impact the tax horizon of the Corporation, the most notable being production, commodity prices and capital spending levels. Gear currently recognizes a deferred tax asset as current tax pools exceed the book value of property, plant and equipment.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2019:

	(M$)
Corporate Acquisition Cost	(116)
Property Acquisition Costs	
Proved properties	248
Undeveloped properties	-
Exploration costs	810
Development costs	36,180
Dispositions	(1,109)
Total	36,013

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2019:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	6	6
Heavy Crude Oil	-	-	10	10
Conventional Natural Gas	-	-	-	-
Dry	-	-	-	-
Service/Other	-	-	-	-
Stratigraphic Test	-	-	-	-
Total	-	-	16	16

See "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*" for a description of the Corporation's exploration and development plans.

Pursuant to the revised budget for the 2020, Gear capped drilling to only those wells that were already completed during the first quarter of 2020, including; seven gross (7 net) heavy crude oil wells in the Lloydminster area and two (2 net) medium oil wells in central Alberta. Gear will continue to monitor prices throughout the year with a vision to potential budget expansion if oil prices strengthen. However, the focus will remain on the delivery of strong project returns and the maintenance of a solid balance sheet. See "*Statement of Reserves Data and Other Oil and Gas Information – Principal Properties*".

Production Estimates

The following tables disclose, by product type, and by area, the total volume of the Corporation's gross production estimated by Sproule for 2020 in the estimates of future net revenue from gross proved and gross probable reserves disclosed under "*Disclosure of Reserves Data*".

From Gross Proved Reserves:	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	BOE (BOE/d)	%
Wildmere	-	1,337	156	-	1,363	20
Celtic	-	1,685	-	-	1,685	25
Wilson Creek	537	-	1,430	186	961	14
Tableland	1,026	-	-	-	1,026	15
Other	474	850	1,926	42	1,688	25
Total	2,037	3,872	3,512	228	6,722	100

Note:

(1) Columns may not add due to rounding.

From Gross Probable Reserves:	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	BOE (BOE/d)	%
Wildmere	-	180	40	-	187	14
Celtic	-	406	-	-	406	31
Wilson Creek	92	-	146	20	136	11
Tableland	314	-	-	-	314	24
Other	15	220	68	2	248	19
Total	421	806	254	21	1,290	100

Note:

(1) Columns may not add due to rounding.

Production History

The following tables summarize certain information in respect of production (which includes royalty interest volumes), product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2019			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production(1)				
Light and Medium Crude Oil (bbls/d)(2)	1,763	2,059	2,166	1,863
Heavy Crude Oil (bbls/d) (2)	4,034	3,929	4,104	4,148
Conventional Natural Gas (Mcf/d) (3)	4,935	4,295	3,977	3,787
NGLs (bbls/d)	269	218	228	235
Combined (BOE/d)	6,888	6,922	7,161	6,877
Average Price Received				
Light and Medium Crude Oil ($/bbl)(2)	64.82	65.88	71.60	63.64
Heavy Crude Oil ($/bbl) (2)	49.17	52.93	60.45	52.89
Conventional Natural Gas ($/Mcf) (3)	2.36	0.79	0.92	2.40
NGLs ($/bbl)	22.79	26.70	13.11	26.40
Combined ($/BOE)	47.97	50.97	57.23	51.44
Royalties Paid				
Light and Medium Crude Oil ($/bbl)(2)	6.93	7.26	7.75	5.27
Heavy Crude Oil ($/bbl) (2)	6.57	7.04	7.69	4.71
Conventional Natural Gas ($/Mcf) (3)	(0.11)	0.26	0.09	(0.07)
NGLs ($/bbl)	(0.68)	(8.15)	2.01	2.97
Combined ($/BOE)	5.52	6.06	6.87	4.33

	2019			
	Dec. 31	Sept. 30	June 30	Mar. 31
Operating Expenses ($/BOE)				
Light and Medium Crude Oil ($/bbl)(2)	19.61	16.00	16.92	20.28
Heavy Crude Oil ($/bbl) (2)	17.19	17.77	18.55	17.20
Conventional Natural Gas ($/Mcf) (3)	3.34	3.23	3.51	4.39
NGLs ($/bbl)	11.42	11.21	11.89	12.99
Combined ($/BOE)	17.93	17.20	18.08	18.73
Netback Received ($/BOE)(4)				
Light and Medium Crude Oil ($/bbl)(2)	38.28	42.62	46.93	38.09
Heavy Crude Oil ($/bbl) (2)	25.40	28.11	34.21	30.98
Conventional Natural Gas ($/Mcf) (3)	(0.88)	(2.70)	(2.68)	(1.92)
NGLs ($/bbl)	12.05	23.64	(0.79)	10.44
Combined ($/BOE)	24.52	27.71	32.28	28.38

Notes:

(1) Before deduction of royalties.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas and by-products from oil wells. Includes immaterial volumes of production from coal bed methane reserves.
(4) Netbacks are calculated by subtracting royalties, and operating and transportation costs from revenues.

The following table indicates the Corporation's average daily production from its important areas for the year ended December 31, 2019:

	Light and Medium Crude Oil(1) (bbls/d)	Heavy Crude Oil(1) (bbls/d)	Conventional Natural Gas(2) (Mcf/d)	NGLs (bbls/d)	BOE (BOE/d)
Celtic	-	1,796	-	-	1,796
Wildmere	-	1,301	356	-	1,360
Wilson Creek	584	-	1,578	187	1,034
Tableland	905	-	-	-	905
Other	474	956	2,318	51	1,867
Total	1,963	4,053	4,252	238	6,962

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.

The Corporation's production for the year ended December 31, 2019 was 58% heavy crude oil, 28% light and medium oil, 10% natural gas and 4% was NGLs. For the year ended December 31, 2019, approximately 98% of the Corporation's gross revenue was derived from crude oil and NGLs production and 2% was derived from natural gas production.

DIVIDEND POLICY

The Corporation has never declared or paid any cash dividends on the Common Shares. The Corporation currently intends to retain future earnings, if any, for future operations, expansion and debt repayment. Any decision to declare and pay dividends will be made at the discretion of the Board and will depend on, among other things, the Corporation's results of operations, current and anticipated cash requirements and surplus, financial condition, contractual restrictions and financing agreement covenants, solvency tests imposed by corporate law and other factors that the Board may deem relevant.

In addition to the foregoing, the Corporation's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future including the terms of the Credit Facilities. The Credit Facilities prohibits the Corporation from declaring or paying any dividends to any of its shareholders if: (i) if declaring or paying the dividend would result in a default under the Credit Facilities; or (ii) during the continuance of a borrowing base shortfall, which is the amount by which the aggregate of all outstanding obligations under the Credit Facilities exceeds the then current borrowing base of the Credit Facilities as a result of a reduction or redetermination of the borrowing base (until cured).

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of Preferred Shares, issuable in series, and an unlimited number of Series 1 Preferred Shares, of which 216,463,002 Common Shares and no Series 1 Preferred Shares are currently issued and outstanding. Additionally, the Corporation has $13.2 million aggregate principal amount of Convertible Debentures outstanding. An aggregate of 15.2 million additional Common Shares may be issued on conversion of the Convertible Debentures that remain outstanding at the date hereof. The following is a summary description of the rights, privileges, restrictions and conditions attaching to the Common Shares, the Preferred Shares, the Series 1 Preferred Shares and the Convertible Debentures.

Common Shares

The Corporation has an unlimited number of Common Shares authorized. The holders of Common Shares are entitled to: dividends if, as and when declared by the Board; to vote at any meetings of the holders of Common Shares; and upon liquidation, dissolution or winding up of the Corporation, receive the remaining property and assets of the Corporation. All of the Common Shares outstanding are fully paid and non-assessable.

Preferred Shares

Gear is authorized to issue an unlimited number of Preferred Shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board prior to the issuance thereof. With respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding up of Gear, whether voluntary or involuntary, the Preferred Shares are entitled to preference over the Common Shares and any other shares ranking junior to the Preferred Shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the Preferred Shares as may be determined at the time of creation of such series.

Series 1 Preferred Shares

At the date hereof, Gear has created Series 1 Preferred Shares; however, no Series 1 Preferred Shares are outstanding. The holders of Series 1 Preferred Shares are not entitled to receive notice of, attend nor vote at any meetings of the shareholders of the Corporation. Subject to the provisions of any other series of Preferred Shares created after the date of the creation of the Series 1 Preferred Shares, the holders of Series 1 Preferred Shares are entitled to receive, if, as and when declared by the Board, any dividends declared by the Board. Any dividends declared and paid on the Common Shares must also be declared and paid on the Series 1 Preferred Shares, which shall be in priority to the holders of the Common Shares. In the event of liquidation, dissolution or winding-up of the Corporation or any other distribution of assets of the Corporation among its shareholders for the purposes of winding up the affairs of the Corporation, the Series 1 Preferred Shares shall rank in priority to the Common Shares in a sum equivalent to the value of the Series 1 Preferred Shares; provided that the amount to be received by the Series 1 Preferred Shares will be equivalent to the amount to be received per Common Share upon such liquidation, dissolution or winding up and subject to the provisions of any other series of Preferred Shares created after the date of the creation of the Series 1 Preferred Shares.

Convertible Debentures

On November 30, 2015, the Corporation issued $14.8 million aggregate principal amount of Convertible Debentures at a price of $1,000 per Convertible Debenture. The Convertible Debentures are governed by the Convertible Debenture Indenture, which is available for review on www.sedar.com. The Convertible Debentures have a maturity date of November 30, 2020 and carry a coupon of 4.00% per annum payable semi-annually in arrears on November 30th and May 31st until maturity. Each $1,000 principal amount of Convertible Debentures is convertible at the option of the holder at any time prior to the maturity date of the Convertible Debentures, into 1,149.43 Common Shares, representing a conversion price of $0.87 per Common Share. Holders converting their Convertible Debentures are entitled to receive accrued and unpaid interest thereon for the period from the date of the latest interest payment date to, but excluding, the date of conversion. An aggregate of approximately $1.6 million of Convertible Debentures have been converted resulting in the issuance of approximately 1.8 million Common Shares, leaving $13.2 million in Convertible Debentures outstanding.

As of December 31, 2019, the Convertible Debentures are redeemable at the Corporation's option, in whole or in part, at any time at par plus accrued and unpaid interest.

In certain circumstances, the Corporation has the option to satisfy its obligation to repay the principal amount of the Convertible Debentures due at maturity or redemption of the Convertible Debentures by the issuance of Common Shares and the number of such Common Shares will be based on 95% of the weighted average trading price of the Common Shares prior to the date fixed for maturity or redemption.

The Convertible Debentures are direct, subordinated unsecured obligations of the Corporation and rank equally with one another and with all other existing and future subordinated unsecured indebtedness of the Corporation. The conversion price of the Convertible Debentures is subject to standard anti-dilution adjustments as set forth in the Convertible Debenture Indenture.

Reduction in Stated Capital

At the special meeting of shareholders of Gear held on September 20, 2019, shareholders approved a special resolution authorizing a reduction in the stated capital account maintained in respect of the Common Shares by $150 million to $90 million, without any payment or distribution to the shareholders of the Corporation. Such a resolution was necessary in order to allow Gear to implement the NCIB to purchase Common Shares for cancellation. See "*General Development of the Business – Three Year History – Year Ended December 31, 2019*".

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX under the symbol "GXE". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for the periods indicated since the beginning of the year ended December 31, 2019:

	Price Range ($)		**Trading**
Period	**High**	**Low**	**Volume**
2019			
January	0.73	0.55	2,764,542
February	0.68	0.54	4,270,487
March	0.65	0.57	5,471,251
April	0.87	0.58	10,312,035
May	0.78	0.56	3,666,367
June	0.63	0.53	1,577,341
July	0.60	0.455	2,988,940
August	0.50	0.41	5,483,391

Period	Price Range ($) High	Low	Trading Volume
September	0.55	0.445	10,589,291
October	0.48	0.38	2,379,756
November	0.43	0.265	6,301,664
December	0.48	0.415	13,317,705
2020			
January	0.50	0.37	4,494,903
February	0.41	0.25	3,680,806
March (1 - 13)	0.325	0.095	14,670,032

Prior Sales

The following table sets forth the securities of the Corporation issued during the year ended December 31, 2019 that are not listed on the TSX (or any other stock exchange):

Date	Number of Securities	Issue Price Per Security(1) ($)	Type of Security
March 11, 2019	480,000	0.61	Options
August 19, 2019	7,257,000	0.43	Options
November 18, 2019	261,000	0.40	Options

Note:

(1) Represents the exercise price of Options.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of management of the Corporation, none of the securities of the Corporation are held in escrow or are subject to a contractual restriction on transfer as at the date hereof.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The following table sets forth certain information in respect to Gear's directors and executive officers:

Name, Province and Country of Residence	Position(s) with Gear	Principal Occupation During the Five Years Preceding
Greg Bay(1)(3) British Columbia, Canada	Director since August 2019 (previously a director from 2013 to 2016)	Founding Partner and Managing Partner of Cypress Capital Management Ltd., an investment management firm, since 1998.
Harry English(1)(3) Alberta, Canada	Director since June 2014	Corporate director and independent businessman since June 2014. Prior thereto, partner at Deloitte LLP, Calgary since 2002.
Ingram Gillmore Alberta, Canada	President, Chief Executive Officer since May 2010 and a Director since June 2010	President and Chief Executive Officer of the Corporation since May 2010; prior thereto Vice President, Engineering at ARC Resources Ltd. ("**ARC**")
Don T. Gray(1)(2)(3) Arizona, United States of America	Chairman since January 2010 and a Director since February 2009	Private investor; a director of the Corporation since February 2009 and Chairman of the Corporation since

Name, Province and Country of Residence	Position(s) with Gear	Principal Occupation During the Five Years Preceding
		January 2010; Chairman of the Board of Petrus Resources Ltd., a public oil and gas company, since 2010; prior thereto, Mr. Gray was the Chief Executive Officer of Peyto Exploration & Development Corp. (formerly Peyto Energy Trust) ("**Peyto**") from August 2006 to January 2007; prior thereto, Mr. Gray was the President and Chief Executive Officer of Peyto from October 1998 to August 2006.
Scott Robinson(2)(3) Alberta, Canada	Director since July 2019	Vice President, Business Development of Peyto, a public oil and gas company, since November 2019; prior thereto, Executive Vice President Operations and Chief Operating Officer of Peyto from 2006 to February 2019.
Wilson Wang(1)(3) Hawaii, United States of America	Director since August 2019	Managing Partner and founder of Twin Peaks Capital LLC, an investment management firm, since 2014, and founder of HFI Research, a research firm focused on the oil and gas industry since 2015.
Bindu Wyma(2)(3) Alberta, Canada	Director since June 2018	An independent businesswoman; Vice President of Business Development for North America of Talisman Energy Inc. from 2011 to 2015. Prior thereto, Ms. Wyma held various positions at Talisman since 1997.
Yvan Chretien Alberta, Canada	Vice President, Land since September 2010	Vice President, Land of Gear since September 2010; prior thereto, Vice-President, Land at ARC from 2006 to March 2010.
Bryan Dozzi Alberta, Canada	Vice President, Engineering since June 2015	Vice President, Engineering since June 2015; prior thereto, Engineering Manager of the Corporation from April 2014 to June 2015 and Vice President, Business Development at Rock Energy Inc. from December 2010 to December 2012.
David Hwang Alberta, Canada	Vice President, Finance and Chief Financial Officer since June 2011	Vice President, Finance of Gear since June 2011; prior thereto, controller at ARC since 2010 and, prior thereto, manager at ARC since 2006.
Jason Kaluski Alberta, Canada	Vice President, Operations since March 2011	Vice President, Operations of Gear since March 2011; prior thereto, manager of operations for Questerre Energy Corporation from 2008 to 2011.
Dustin Ressler Alberta, Canada	Vice President, Exploration since November 2016	Vice President, Exploration since November 2016; prior thereto, Geology Manager with the Corporation from April 2014 to October 2016 and geologist at Gear from October 2010 to April 2014.
Edward (Ted) Brown Alberta, Canada	Corporate Secretary since August 2015	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 2005.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation and Governance Committee.
(4) Gear does not have an Executive Committee.

(5) Gear's directors will hold office until the next annual general meeting of the Corporation's shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, by all of the directors and officers of Gear is 18,037,508 Common Shares constituting approximately 8% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

Other than as disclosed below, to the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Gear), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**"), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Gear to affect materially the control of Gear: (a) is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Gear) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties or Sanctions

To the knowledge of Gear, no director or executive officer of Gear (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Gear to affect materially the control of Gear, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. In particular, certain of the directors and officers of the Corporation are involved in managerial and/or director positions with other crude 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. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the 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 provided by the ABCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

None of the Corporation or any of its subsidiaries is a party to any legal proceeding nor was it a party to any legal proceeding during the financial year ended December 31, 2019, nor is the Corporation aware of any contemplated legal proceeding involving the Corporation or its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of the Corporation.

Regulatory Actions

During the year ended December 31, 2019, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The Corporation is not aware of any material interests, direct or indirect, of any director or executive officer of the Corporation, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of the Corporation's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect the Corporation, other than as disclosed elsewhere in this Annual Information Form.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), the Corporation has not entered into any material contracts during the last financial year, or before the last financial year which are still in effect, other than the Convertible Debenture Indenture (see "*Description of Capital Structure – Convertible Debentures*"), which is available on www.sedar.com.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are Deloitte LLP, the Corporation's independent auditors and Sproule, the Corporation's independent engineering evaluators.

Interests of Experts

To the Corporation's knowledge, there were no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of its associates or affiliates: (i) held by Sproule or by the "designated professionals" (as defined in Form 51-102F2 to NI 51-102) of Sproule, when Sproule prepared the report, valuation, statement or opinion referred to herein as having been prepared by Sproule; (ii) received by Sproule or by the "designated professionals" of Sproule, after the time specified above; or (iii) to be received by Sproule or by the "designated professionals" of Sproule;

except in each case for the ownership of Common Shares, which in respect of Sproule and Sproule's "designated professionals", as a group, has at all relevant times represented less than one percent of the outstanding Common Shares. In addition, neither Sproule, nor any director, officer or employee of Sproule, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

Deloitte LLP is independent within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the Board is attached hereto as Schedule "C".

Composition of the Audit Committee

The audit committee (the "**Audit Committee**") is comprised of Messrs. Harry English (Chair), Don T. Gray, Greg Bay and Wilson Wang. The following chart sets out the assessment of each of the Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Don T. Gray Alberta, Canada	Yes	Yes	Mr. Gray holds a BSc. in petroleum engineering from Texas A&M University and has over 30 years' experience in the Canadian oil and gas business in various capacities. Mr. Gray is a Co-Founder and former President and Chief Executive Officer of Peyto and is also Chairman and co-founder of Petrus Resources Ltd. and former Chairman of EIQ Capital Corp., a private investment company.
Harry English Alberta, Canada	Yes	Yes	Mr. English graduated with a Bachelor of Science (Honours) from the University of St. Andrews, Scotland in 1976 and is a Chartered Professional Accountant. He spent his 37-year career until May 2014 in professional practice, primarily in the energy business, most recently as a senior audit partner with Deloitte LLP.
Greg Bay Alberta, Canada	Yes	Yes	Mr. Bay obtained his Chartered Financial Analyst designation in 1988 and holds a Bachelor of Commerce in Finance from Brigham Young University. Mr. Bay is Managing Partner of Cypress Capital Management (founding partner) and brings with him over 28 years of experience in the investment industry with emphasis on the oil and gas sector. Mr. Bay holds a director position with the Mullen Group Ltd.
Wilson Wang Hawaii, United States of America	Yes	Yes	Mr. Wang has his Chartered Financial Analyst designation and holds a Bachelor of Business Administration in Finance from the University of Hawaii. Mr. Wang is the Managing Partner and Founder of Twin Peaks Capital LLC, an investment management firm, since 2014, and founder of HFI Research, a research firm focused on the oil and gas industry since 2015.

Each of the members of the Audit Committee is considered "financially literate" and is considered "independent" within the meaning of National Instrument 52-110 – *Audit Committees*.

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

Pre-Approval of Policies and Procedures

The Corporation has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by Deloitte LLP. The Audit Committee will approve the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, reoccurring or otherwise likely to be provided by Deloitte LLP during the current fiscal year and the Audit Committee will be informed of each non-audit service, as applicable. The list of services will be sufficiently detailed as to the particular services to be provided to ensure that the Audit Committee knows precisely what services it is being asked to pre-approve and it will not be necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services.

External Auditors Service Fees

The following table summarizes the fees billed to the Corporation by its auditors, Deloitte LLP, for external audit and other services during the periods indicated:

Year	Audit Fees(1)	Audit -Related Fees(2)	Tax Fees	All Other Fees(3)
	($)	($)	($)	($)
2019	193,670	-	-	102,225
2018	247,170	19,403	-	81,735

Notes:

(1) Represents the aggregate fees incurred by the Corporation in each of the last two fiscal years for audit services.

(2) Represents the aggregate fees incurred in each of the last two fiscal years by the Corporation for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements (and not reported under the heading "Audit Fees").

(3) Represents the aggregate fees billed in each of the last two fiscal years by the Corporation's external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees". In both 2019 and 2018 these amounts relate to consulting fees paid to Deloitte LLP for Gear's regulatory, safety and environmental program.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although laws and regulations are a matter of public record, the Corporation is unable to predict what additional laws, regulations or amendments governments may enact in the future.

The Corporation holds interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian provinces of Alberta, British Columbia and Saskatchewan. The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

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

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

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

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

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Corporation does not directly enter into contracts to export its production outside of Canada.

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

Transportation Constraints and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

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

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

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

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

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

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

While it was expected that construction on the Keystone XL Pipeline, 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. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

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

Crude Oil and Bitumen by Rail

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

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

Natural Gas

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. In October 2018, the joint venture partners of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project, which will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, BC, via the Coastal GasLink pipeline (the "**CGL Pipeline**"), which will be built and operated by TC Energy's subsidiary Coastal GasLink ("**CGL**"). Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell 65% of its interest in the CGL Pipeline, to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction is expected to close in the first half of 2020. The CGL Pipeline's route was altered as a result of feedback that LNG Canada received from Indigenous groups in the area, and on May 1, 2019, the British Columbia Oil and Gas Commission (the "**BC Commission**") approved the current planned route for the CGL Pipeline. However, the CGL Pipeline has faced intense opposition. For example, a challenge to the approval process of the CGL Pipeline was launched in August 2018, contending that it should have been subject to the federal review instead of a provincial review. In July 2019, the NEB confirmed that the CGL Pipeline was properly subject to provincial jurisdiction. In addition, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays of construction activities on the CGL Pipeline. CGL obtained an injunction on December 31, 2019, and enforcement of the injunction started in February 2020. Since that time, there have been rail blockades and protests in support of the Hereditary Chiefs and their opposition to the CGL Pipeline. As a result of the opposition, the Federal Government met with the Hereditary Chiefs to negotiate a solution. The Federal Government and the Hereditary Chiefs did negotiate a deal but the details have not been announced and as such it is unknown what impact the deal could have on the CGL Pipeline and future resource projects involving lands subject to Indigenous land claims.

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

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, In October 2018, the proponents of the LNG Canada liquefied natural gas 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 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, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the 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 prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

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

Curtailment

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

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

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

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

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

The Corporation is not currently subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "**CUSMA**". Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the USMCA. On March 13, 2020, the House of Commons and the Senate passed Bill C-4 ratifying the USMCA. The USMCA will come into force two months from March 13, 2020. Until then, NAFTA remains the North American trade agreement currently in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

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

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

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

Land Tenure

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

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

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan, and Manitoba approximately 19%, 6%, 20%, and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

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

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

Royalties and Incentives

General

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

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

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

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act (Alberta)*, came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

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

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

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

Minerals Act was amended in 2014, and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

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

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

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

British Columbia

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

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

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

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

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments, and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and is subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGLs is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

Freehold and Other Types of Non-Crown Royalties

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

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

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

Regulatory Authorities and Environmental Regulation

General

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

Federal

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

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

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

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

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

Alberta

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

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

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

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**BC Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The British Columbia Government passed *Bill 51 – 2018: Environmental Assessment Act in* late 2018, which will replace the environmental assessment regime that has been in place since 2002. The updated *Environmental Assessment Act* is not yet in force. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process. The new environmental assessment process aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building, in alignment with British Columbia's recent passage of Bill 41, which affirmed and adopted the United Nations Declaration on the Rights of Indigenous Peoples. Simultaneously with the enactment of the *Environmental Assessment Act*, the British Columbia Government enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project. However, many details of the new assessment process remain unknown, but the British Columbia Government has released a proposed timetable for the release of supplementary and informational materials through 2020.

In 2018, the British Columbia Government proposed amendments to the BC EMA that would see new heavy crude oil imports, whether by rail, expanded pipeline, or otherwise, managed through a discretionary permitting process (the "**Proposed Amendments**"). The Proposed Amendments would directly affect the transport of heavy crude oil blends across British Columbia to tidewater through the Trans Mountain Pipeline. In its unanimous decision, the *Reference Re Environmental Management Act* (British Columbia) delivered May 24, 2019; the British Columbia Court of Appeal held that the Proposed Amendments are unconstitutional. The Supreme Court of Canada heard British Columbia's appeal on January 16, 2020, and found that, constitutionally, the British Columbia Government does not have the jurisdiction to make the Proposed Amendments. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. On January 29, 2020, the Government of British Columbia acknowledged that Canada's highest court has ruled in support of the Trans Mountain Pipeline expansion proceeding, and indicated that the Government of British Columbia would not initiate further challenges against the Trans Mountain Pipeline.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the act governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations, 2012* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The aim of the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. The Government of Saskatchewan has implemented a number of operational requirements, including an increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex Database.

Liability Management Rating Program

Alberta

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

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

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program, including the Corporation, fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation (Re)* ("**Redwater**"), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company’s valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

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

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

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets. Gear is participating in the AER ABC program for 2020 targeting liabilities in our Wildmere field.

British Columbia

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

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

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

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

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 fuel charge 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. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and the Court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

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

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

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

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

British Columbia

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

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

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

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

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. Subsequently, the Government released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

The MRGGA, which is partially compliant with the federal emissions trading system, was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full in December 18, 2018, establishing the framework of an output-based emissions management framework.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations,* and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations")** came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonne CO2e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO2e between 2020 and 2030.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the Province's progress on goals set out under *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

On October 1, 2019, *Bill 147 – An Act to amend The Oil and Gas Conservation Act*, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

RISK FACTORS

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

Public Health Crisis

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as the recent COVID-19 (coronavirus), may adversely affect the Corporation

The Corporation's business, operations and financial condition could be materially adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China. On January 30, 2020, the World Health Organization declared the outbreak a global health emergency and on March 11, 2020, the World Health Organization declared the outbreak a pandemic. In China, reactions to the spread of COVID-19 have led to, among other things, significant restrictions on travel within China, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread throughout Europe and the Middle East and there have been cases of COVID-19 in Canada and the United States, causing the governments of most western countries, including Canada and the United States, to take certain actions to reduce the spread of the virus. Such actions have included imposing restrictions such as quarantines, school closures, restrictions on public gatherings, business closures and travel restrictions. While these effects are expected to be temporary, the duration of the business disruptions internationally and related financial impact cannot be reasonably estimated at this time. Similarly, the Corporation cannot estimate whether or to what extent this outbreak and the potential financial impact may extend to countries outside of those currently impacted. Such public health crises can result in volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, oil prices have significantly weakened in response to the outbreak of COVID-19. See "*Risk Factors – Volatility and Weakness in the Oil and Natural Gas Industry*". The risks to the Corporation of such public health crises also include risks to employee health and safety and a slowdown or temporary suspension of operations in geographic locations impacted by an outbreak. At this point, the extent to which COVID-19 may impact the Corporation is uncertain; however, it is possible that COVID-19 may have a material adverse effect on the Corporation’s business, results of operations and financial condition.

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

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

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

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

Weakness and Volatility in the Crude Oil and Natural Gas Industry

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

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

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, 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. See "*Risk Factors – Reserves Estimates*". 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. See "*Risk Factors – Credit Facilities*". In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. See "*Risk Factors – Additional Funding Requirements*".

Prices, Markets and Marketing

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

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

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

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the crude oil and natural gas Industry*".

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

Exploration, Development and Production Risks

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

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

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

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

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

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

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

Market Price of Common Shares

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the crude oil and natural gas industry

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the crude oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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

Political Uncertainty

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

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. The

Canadian Parliament has not yet passed legislation to implement the USMCA. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the crude oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the 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 crude oil and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project while a minority government in British Columbia remains opposed to the project and has attempted to regulate the transport of heavy crude oil products into and through British Columbia. Though the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy crude oil products into and through British Columbia, disputes remain between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdictions.

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 crude oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Political instability, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the crude oil and natural gas industry. See "*Industry Conditions – Climate Change Regulation"*, "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

Project Risks

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

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

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling hydraulic fracturing and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;

- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- regulation of the crude oil and natural gas industry by various levels of government and governmental agencies.

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

Reliance on a Skilled Workforce and Key Personnel

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

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

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

Gathering and Processing Facilities, Pipeline Systems and Rail

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

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the crude oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the CEAA 2012 were repealed. In addition, the IA Agency replaced the CEA Agency. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

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

Operational Dependence

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

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

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

Cost of New Technologies

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

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

Alternatives to and Changing Demand for Petroleum Products

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

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

Regulatory

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

The implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the crude oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*". Also, in response to widening pricing differentials, the Government of Alberta implemented production curtailment. See "*Industry Conditions – Curtailment"* and *"Risk Factors – Liability Management"*.

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

Royalty Regimes

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

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

Environmental

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

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

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Liability Management

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

Alberta, British Columbia and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the AB LMR Program administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to the Corporation's 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. In addition, the AB LMR Program may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. This is of particular concern to junior oil and natural gas companies that may be disproportionately affected by price instability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

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

Chronic Climate Change Risks

The Corporation's exploration and production facilities and other operations and activities emit GHG which may require the Corporation 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 its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

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

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

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas production, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. As at the date hereof, Gear's current emission levels are not subject to any climate change regulations. See "*General Description of the Business – Environmental Considerations and Protection*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk Associated with the Corporation's Operations*" and "*Risk Factors – Changing Investor Sentiment*".

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. None of the Corporation's assets are located in locations that are proximate to forests / rivers and a wildfire / flood will not lead to significant downtime and/or damage to such assets. Moreover, extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

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

Substantial Capital Requirements

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

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

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

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

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

Additional Funding Requirements

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

The 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 natural gas acquisition, exploration and development activities. Failure to obtain 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. Due to the conditions in the crude oil and natural gas industry and/or global economic and political volatility, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the crude oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

As a result of global economic and political conditions and the domestic lending landscape, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause the Corporation to 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 are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to additional capital or being required to repay all amounts owing thereunder

The Corporation currently has the Credit Facilities and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the Credit Facilities which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Credit Facilities, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facilities may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. As a result of the depressed commodity prices experienced in the last two (2) years, the Corporation's borrowing base was reduced in May 2019. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Continued depressed commodity prices or further reductions in commodity prices could result in a further reduction to the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

The Supreme Court of Canada's decision in Redwater may give rise to new covenants and restrictions under the Corporation's credit facilities, should LMR levels fall below existing agreed-upon thresholds, including further limitations on asset dispositions and acquisitions. The Corporation may also be required to provide additional reporting to its lenders regarding its existing and/or budgeted abandonment and reclamation obligations, its decommissioning expenses, its LMR and/or any notices or orders received from an energy regulator in any applicable province. The Corporation's lenders may also be permitted to re-determine the Corporation's borrowing base (at the sole cost of the Corporation) following a decline in its LMR below a certain threshold or if the Corporation becomes subject to an abandonment and reclamation order and its estimated cost of compliance with such order exceeds a certain threshold See also "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

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

Issuance of Debt

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

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

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk

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

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

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

Availability and Cost of Material and Equipment

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

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

Title to and Right to Produce from Assets

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

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

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

Reserves Estimates

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

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

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

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

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

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

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

Insurance

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

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

Non-Governmental Organizations

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

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

Dilution

The Corporation may issue additional Common Shares, diluting current shareholders

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

Management of Growth

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

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

Expiration of Licenses and Leases

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

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

Dividends

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

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

Litigation

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

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

Indigenous Claims

Indigenous claims may affect the Corporation

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

Breach of Confidentiality

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

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

Income Taxes

Taxation authorities may reassess the Corporation's tax returns

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable 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 an impact on current and future taxes payable.

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

Seasonality

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

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Certain of the Corporation's oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of impassable muskeg.

Third Party Credit Risk

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

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

Information Technology Systems and Cyber-Security

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

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

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

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

Social Media

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

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

Conflicts of Interest

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

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Executive Officers – Conflicts of Interest*".

Expansion into New Activities

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

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

Forward-Looking Information

Forward-looking information may prove inaccurate

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

Hydraulic Fracturing

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

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

Alberta

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

British Columbia

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how B.C.'s regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. Despite a timeline to fulfill its mandate by December 31, 2018, the panel's findings are not yet publically available. Therefore, it is unclear how the panel's recommendations will influence the regulatory regime currently in place in B.C. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Corporation's business operation, financial condition, results of operations and prospects.

Due to seismic activity recorded in the Kiskatinaw Seismic Monitoring and Mitigation ("**Kiskatinaw**") area, in May 2018, the BC Commission issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BC Commission, and the suspension of operations if a seismic event above a 3.0 magnitude occurs. In November 2018, seismic activity near Fort St. John in the Kiskatinaw area resulted in the suspension of several companies' operations, demonstrating the BC Commission's willingness to enforce these enhanced regulatory requirements. The BC Commission continues to monitor seismic events across the province and may implement similar requirements in other areas if necessary.

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. Under the *Water Sustainability Act*, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the *Dam Safety Regulation*. Larger dams are also subject to an environmental assessment and approval under the *Environmental Assessment Act*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. While the B.C. Commission has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent the relevant industry regulators will respond to this issue.

The Corporation may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where the Corporation is not strictly complying with the current regulatory framework.

Waterflood

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

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

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

Competition

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

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

Changing Investor Sentiment

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

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

Reputational Risk Associated with the Corporation's Operations

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

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

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

Diluent Supply

A decrease in, or restriction in access to, diluent supply may increase the Corporation's operating costs

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

Carbon Pricing Risk

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

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

Disposal of Fluids Used in Operations

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

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

Unauthorized use of intellectual property may cause the Corporation to engage in, or be the subject of, litigation

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

(a) pay substantial damages and/or cease the development, use, sale or importation of processes that infringe upon other patented intellectual property;

(b) expend significant resources to develop or acquire non-infringing intellectual property;

(c) discontinue processes incorporating infringing technology; or

(d) obtain licences to the infringing intellectual property.

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

ADDITIONAL INFORMATION

Additional information relating to Gear may be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Gear's securities and securities authorized for issuance under equity compensation plans is contained in Gear's management information circular relating to the Corporation's most recent annual meeting of shareholders that involved the election of directors.

Additional information is also provided in Gear's financial statements and management's discussion and analysis for the year ended December 31, 2019, which documents may be found on SEDAR at www.sedar.com.

SCHEDULE "A"

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

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

1. We have evaluated the Company's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	**Total**
Sproule Associates Limited	December 31, 2019	Canada	Nil	423,390	Nil	423,390

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

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

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

EXECUTED as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, Canada, February 4, 2020.

(Signed) "Stephanie D. Brunt"

Stephanie D. Brunt, P.Eng.
Project Leader; Petroleum Engineering

SCHEDULE "B"

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

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

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "A" to this Annual Information Form.

The Reserves Committee of the board of directors of the Corporation has

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

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

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

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

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

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

(c) the content and filing of this report.

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

Per: (signed) "*Ingram Gillmore*"
Ingram Gillmore
President, Chief Executive Officer and Director

Per: (signed) "*Bryan Dozzi*"
Bryan Dozzi
Vice President, Engineering

Per: (signed) "*Donald T. Gray*"
Donald T. Gray
Director

Per: (signed) "*Bindu Wyma*"
Bindu Wyma
Director

March 16, 2020

SCHEDULE "C"

GEAR ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Gear Energy Ltd. ("**Gear**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;

2. the oversight of management's reporting on internal accounting standards and practices;

3. the review of financial information, accounting systems and procedures;

4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

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

6. To provide better communication between Directors and external auditors;

7. To enhance the external auditor's independence;

8. To increase the credibility and objectivity of financial reports; and

9. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Gear ("**Management**") and external auditors.

MEMBERSHIP OF COMMITTEE

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

2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

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

4. For the purposes of this Mandate, "financially literate" has the meaning ascribed thereto in NI 52-110 and means that the member 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 Corporation's financial statements.

MANDATE AND RESPONSIBILITIES OF COMMITTEE

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between Management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Gear's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process may include but not be limited to:

   - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between Management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Gear's disclosure of other financial information and must periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

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

6. Review with external auditors (and internal auditor if one is appointed by Gear) their assessment of the internal controls of Gear, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Gear and its subsidiaries.

7. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

8. To review and satisfy itself on behalf of the Board that management has adequate procedures in place for reporting and certification under the *Extractive Sector Transparency Measures Act* (Canada) ("**ESTMA**") when the Corporation is required to comply with ESTMA.

9. Establish a procedure for:

    - the receipt, retention and treatment of complaints received by Gear regarding accounting, internal accounting controls or auditing matters; and

    - the confidential, anonymous submission by employees of Gear of concerns regarding questionable accounting or auditing matters.

10. Review and approve Gear's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Gear. All employees of Gear are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Gear without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Gear will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

7. The Committee may invite such officers, directors and employees of the Corporation and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to Directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation as determined by the Committee.

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

11. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Committee Chair.

12. Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The Committee may adopt additional policies and procedures as it deems necessary from time to time to fulfill its responsibilities.

March 26, 2018