KELT EXPLORATION LTD.

ANNUAL INFORMATION FORM

For the Year Ended
December 31, 2019

March 6, 2020

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APPENDICES

SELECTED DEFINITIONS

In this Annual Information Form, the following terms have the meanings set forth below, unless otherwise indicated. Additional terms relating to reserves and other oil and gas information have the meanings set forth in Appendix C – Definitions Used for Reserves Categories.

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

"**Amended and Restated Credit Agreement**" has the meaning set forth under the heading "*General Development of the Business – History of Kelt – Developments Subsequent to the Arrangement and the Arrangement Acquisition*".

"**Annual Information Form**" means this annual information form of the Corporation dated March 6, 2020.

"**Artek**" means Artek Exploration Ltd.

"**Arrangement**" means the plan of arrangement as more particularly described under the heading "*General Development of the Business – History of Kelt – The Arrangement and the Arrangement Acquisition*".

"**Arrangement Acquisition**" means the acquisition of certain assets by Kelt from Celtic as more particularly described under the heading "*General Development of the Business – History of Kelt – The Arrangement and the Arrangement Acquisition*".

"**Board of Directors**" means the board of directors of Kelt.

"**Celtic**" means Celtic Exploration Ltd.

"**Celtic Shares**" has the meaning set forth under the heading "*General Development of the Business – History of Kelt – Developments Subsequent to the Arrangement and the Arrangement Acquisition*".

"**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 and Petroleum (Petroleum Society), as amended from time to time.

"**Common Shares**" means the common shares of Kelt.

"**Credit Facilities**" means the credit facilities established under the Second Amended and Restated Credit Agreement, as amended.

"**IFRS**" means International Financial Reporting Standards.

"**Karr Disposition**" has the meaning set forth under the heading "*General Development of the Business – History of Kelt – 2017*".

"**Kelt**" or the "**Corporation**" means Kelt Exploration Ltd.

"**Kelt Debentures**" has the meaning set forth under the heading "*General Development of the Business – History of Kelt – Developments Subsequent to the Arrangement and the Arrangement Acquisition*".

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

"**NI 51-102**" means National Instrument 51-102 – *Continuous Disclosure Obligations*.

"**NI 52-110**" means National Instrument 52-110 – *Audit Committees*.

"**Options**" means the options to acquire Common Shares.

“**Pouce Coupe/Spirit River Acquisition**” has the meaning set forth under the heading “*General Development of the Business – History of Kelt – Developments Subsequent to the Arrangement and the Arrangement Acquisition*”.

“**Preferred Shares**” means the preferred shares of Kelt.

“**Purchaser**” means ExxonMobil Celtic ULC.

“**RSUs**” means the restricted share units of Kelt.

“**Second Amended and Restated Credit Agreement**” has the meaning set forth under the heading “*General Development of the Business – History of Kelt – 2019*”.

“**Sproule**” means Sproule Associates Limited, independent petroleum engineers of Calgary, Alberta.

“**Sproule Report**” means the report prepared by Sproule dated February 13, 2020 and effective as of December 31, 2019 entitled “*Evaluation of the P&NG Reserves of Kelt Exploration Ltd. (As of December 31, 2019)*”.

“**Syndicated Credit Agreement**” has the meaning set forth under the heading “*General Development of the Business – History of Kelt – Developments Subsequent to the Arrangement and the Arrangement Acquisition*”.

“**TSX**” means the Toronto Stock Exchange.

PRESENTATION OF INFORMATION

The information contained in this Annual Information Form is presented as at December 31, 2019 except where otherwise noted. In this Annual Information Form, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

ABBREVIATIONS AND CONVERSIONS

Abbreviations

The following abbreviations have the meanings set forth below.

AECO	Alberta Energy Company interconnect with Nova system, the Canadian benchmark for natural gas pricing
API	American Petroleum Institute
bbl/d	Barrels per day
bbls	Barrels
BOE	Barrel of oil equivalent of natural gas and crude oil on the basis of one bbl of crude oil for 6 Mcf of natural gas
BOE/d	Barrel of oil equivalent per day
Lt	Long tons
Lt/d	Long tons per day
M$	Thousands of dollars
m^3	Cubic metres
Mbbl	Thousand barrels
MBOE	Thousand barrels of oil equivalent
Mcf	Thousand cubic feet
Mcf/d	Thousand cubic feet per day
MMBtu	One million British thermal units
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
NGL	Natural gas liquids
WTI	West Texas Intermediate of Cushing, Oklahoma, the benchmark for crude oil pricing purposes

Non-GAAP Measures

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. Kelt uses "netback" or "operating netback" as a key performance indicator and it is used by Kelt in operational and capital allocation decisions. It is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. Readers are cautioned, however, that this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles in Canada as an indication of Kelt's performance.

Conversions

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

To Convert From	To	Multiply By
Mcf	m^3	28.174
m^3	Cubic feet	35.494
Bbls	m^3	0.159
m^3	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.500 (Alberta and British Columbia)
Gigajoules	MMBtu	0.950
MMBtu	Gigajoules	1.0526

Caution Respecting BOE

In this Annual Information Form, the abbreviation BOE means a barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

FORWARD-LOOKING STATEMENTS AND INFORMATION

This Annual Information Form contains forward-looking statements and forward-looking information (collectively, "**forward-looking statements**"). These statements relate to future events or Kelt's future performance. All statements other than statements of historical fact may be forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology. These statements are only predictions. Actual events or results may differ materially. In addition, this Annual Information Form may contain forward-looking statements attributed to third party industry sources. Although the Corporation believes these publications and reports can be reasonably relied-on, it has not independently verified any of the data or other statistical information contained therein, nor has it ascertained or validated the underlying economic or other assumptions. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Forward-looking statements in this Annual Information Form include, but are not limited to, statements with respect to:

- capital expenditure programs and future capital requirements and the timing and method of financing thereof;
- the Corporation's exploration and development activities;
- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- the production from Kelt's assets;
- results of various projects of Kelt;
- estimated abandonment and reclamation costs;
- the Corporation's access to adequate pipeline capacity and third-party infrastructure;
- growth expectations within Kelt;
- the performance and characteristics of Kelt's oil and natural gas properties;
- the quantity and quality of the Corporation's oil and natural gas reserves;
- timing of development of undeveloped reserves;
- the tax horizon and taxability of Kelt;
- supply and demand for oil, natural gas liquids and natural gas;
- Kelt's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- realization of the anticipated benefits of acquisitions and dispositions;
- commodity prices and costs;
- the dividend policy of Kelt;
- Kelt's hedging activities;
- industry conditions pertaining to the oil and gas industry; and
- treatment under government regulation and taxation regimes.

With respect to forward-looking statements contained in this Annual Information Form, Kelt has made assumptions regarding, among other things:

- future crude oil, natural gas and NGL prices and commodity prices generally;
- future exchange rates;
- the ability of Kelt to obtain qualified staff, drilling and related equipment in a timely and cost-efficient manner to meet its needs;
- the timing and amount of capital expenditures;
- future operating costs and future cash flow;

- future capital expenditures to be made by the Corporation;
- future sources of funding for the Corporation's capital program;
- the Corporation's future debt levels;
- oil, natural gas and NGL production levels;
- prevailing weather conditions;
- general economic and financial market conditions;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- production of new and existing wells and the timing of new wells coming on-stream;
- the performance characteristics of oil and natural gas properties;
- the size of Kelt's oil, natural gas and NGL reserves and the recoverability of its reserves;
- the ability to raise capital and to continually add to reserves through exploration and development;
- the success of exploration and development activities;
- the Corporation's ability to market production of oil and natural gas successfully to customers;
- the applicability of technologies for recovery and production of the Corporation's reserves;
- the geography of the areas in which the Corporation is conducting exploration and development activities; and
- the impact of competition on the Corporation.

Although Kelt believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Kelt cannot guarantee future results, levels of activity, performance, or achievements. Moreover, neither Kelt nor any other person assumes responsibility for the outcome of the forward-looking statements. There are many risks and other factors beyond Kelt's control which could cause results to differ materially from those expressed in the forward-looking statements contained in this Annual Information Form. These risks and other factors include, but are not limited to:

- general economic and political conditions in Canada, the United States and globally;
- industry conditions, including fluctuations in the price of oil, natural gas liquids and natural gas;
- liabilities inherent in oil and natural gas operations;
- environmental and climate change risks;
- availability of equity and debt financing;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to realize anticipated benefits of acquisitions and dispositions;
- failure to obtain industry partner and other third party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisitions or reserves, undeveloped land and skilled personnel;
- competition for and inability to retain drilling rigs and other services;
- right to surface access;
- the need to obtain required approvals from regulatory authorities; and
- the other factors considered under "*Risk Factors*" in this Annual Information Form.

These factors should not be considered as exhaustive. Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

The above summary of assumptions and risks related to forward-looking information has been provided in this Annual Information Form in order to provide readers with a more complete perspective on Kelt's future operations. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Kelt is not under any duty to update or revise any of the forward-looking statements except as expressly required by applicable securities laws.

CORPORATE STRUCTURE

Name, Address and Incorporation

The Corporation was incorporated under the ABCA on October 11, 2012 as "1705972 Alberta Ltd." On October 19, 2012, Articles of Amendment were filed to change the name of the company to "Kelt Exploration Ltd." On November 7, 2012, Kelt filed Articles of Amendment to remove the private company restrictions on share transfers and to amend the minimum number of directors to three (3).

Kelt Exploration (LNG) Ltd. (formerly, Artek Exploration Ltd.), a corporation incorporated under the ABCA, is a wholly-owned subsidiary of the Corporation. Kelt does not have any other subsidiaries.

The head office of Kelt is located at Suite 300, 311 – 6th Avenue S.W., Calgary, Alberta T2P 3H2 and its registered office is located at Suite 1900, 520 – 3rd Avenue S.W., Calgary, Alberta T2P 0R3.

GENERAL DEVELOPMENT OF THE BUSINESS

Overview

Kelt is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources, primarily in northwestern Alberta and northeastern British Columbia. Kelt's land holdings are located in four operating divisions, namely: (a) Pouce Coupe/Progress, Alberta - Kelt's Alberta development division; (b) Wembley/Pipestone, Alberta – Kelt's Alberta exploration division; (c) Inga/Fireweed, British Columbia – Kelt's B.C. development division; and (d) Oak/Flatrock, British Columbia – Kelt's B.C. exploration division. Kelt also has a number minor properties not included in the four operating divisions. See "*Description of the Business*" and "*Statement of Reserves Data and Other Oil and Gas Information*".

History of Kelt

The Arrangement and the Arrangement Acquisition

Kelt was incorporated on October 11, 2012 for the purposes of participating in the plan of arrangement under section 193 of the ABCA involving the Corporation, Celtic, ExxonMobil Canada Ltd., the Purchaser and the shareholders and debentureholders of Celtic (the "**Arrangement**"). Prior to February 26, 2013, Kelt had not carried on any active business other than in connection with the Arrangement and related matters. The Arrangement was completed on February 26, 2013 pursuant to which, among other things, the Purchaser acquired all of the issued and outstanding common share of Celtic ("**Celtic Shares**"), including the Celtic Shares issued upon the conversion of convertible unsecured subordinated debentures of Celtic, for cash consideration of $24.50 per Celtic Share. In addition, each shareholder received one-half (1/2) of one Common Share of Kelt for each Celtic Share held.

Pursuant to the Arrangement and the asset conveyance agreement between Celtic and Kelt made as of February 26, 2013, Celtic assigned and transferred to Kelt all of Celtic's right, title, estate and interest in and to the petroleum, natural gas and related hydrocarbon rights and related personal property interests within, upon or under the lands and leases in the following properties, namely, a natural gas property located at Grande Cache, Alberta, a liquids rich natural gas property located at Inga, British Columbia and an oil prospect located at Karr, Alberta (the "**Arrangement Acquisition**").

Immediately following the completion of the Arrangement and the Arrangement Acquisition, Kelt completed a non-brokered private placement whereby it issued an aggregate of 6,000,000 Common Shares at a subscription price of $2.32 per Common Share, which was equal to the estimated net asset value of Kelt on a per share basis immediately following completion of the Arrangement, resulting in aggregate gross proceeds of $13.92 million to Kelt.

Immediately following the completion of the Arrangement and the Arrangement Acquisition, Kelt completed the establishment of a revolving operating demand loan credit facility in the amount of $40.0 million, which was later increased to $100.0 million in connection with the Pouce Coupe/Spirit River Acquisition.

Since the completion of the Arrangement and the Arrangement Acquisition on February 26, 2013, Kelt has carried on the business of the exploration for, and the development and production of, oil and natural gas.

On March 1, 2013, the Common Shares commenced trading on the TSX under the stock symbol "KEL".

Developments Subsequent to the Arrangement and the Arrangement Acquisition

On August 9, 2013, Kelt completed the acquisition of certain natural gas and NGL assets located in the Fireweed area, British Columbia, adjacent to Kelt's property located at Inga, in northeastern British Columbia effective as of April 1, 2013 for a purchase price, before closing adjustments, of $15.5 million. Also included among the assets acquired was an interest in a compression and dehydration facility with approximately 16 MMcf/d of gross natural gas capacity and 25 kilometers of pipeline.

On December 20, 2013, Kelt completed the acquisition of certain crude oil and natural gas assets located at Pouce Coupe/Spirit River, Alberta, in close proximity to its core producing areas at Grande Cache and Karr in west central Alberta (the "**Pouce Coupe/Spirit River Acquisition**"). The effective date of the Pouce Coupe/Spirit River Acquisition was October 1, 2013 and the purchase price, before closing adjustments, was $191.96 million, which was financed in part from the proceeds from the private placement of subscription receipts of the Corporation. Also included among the assets acquired was a major infrastructure component with interest in major oil and gas facilities including a 20.2% interest in a 140 MMcf/d gas processing plant, varying ownership interests in gas compressors, oil batteries, in an extensive network of oil and gas gathering pipelines and an established field office located in Grande Prairie, Alberta. On February 10, 2014, Kelt completed the disposition of certain non-core and non-operated assets that were included in the Pouce Coupe/Spirit River Acquisition.

On May 6, 2014, Kelt entered into a syndicated credit agreement (the "**Syndicated Credit Agreement**") with a syndicate of lenders and established credit facilities in the aggregate amount of $100.0 million, which was amended on November 28, 2014 to increase the amount of the credit facilities thereunder to the aggregate amount of $235.0 million.

On July 2, 2014, Kelt completed the acquisition of a private Canadian oil and gas company with crude oil and natural gas assets located at Valhalla/La Glace, adjacent to Kelt's core producing areas at Pouce Coupe and Spirit River in west central Alberta for consideration paid by Kelt, before adjustments, of $165.0 million, consisting of $107.0 million in cash (including repayment of all outstanding debt of the target company) and the issuance of 4,270,956 Common Shares with an aggregate value of $58.0 million.

On December 18, 2014, Kelt completed the acquisition of certain natural gas and NGL assets located in the Stoddart area of British Columbia, adjacent to Kelt's properties located at Inga and Fireweed, in northeastern British Columbia effective as of October 1, 2014 for a purchase price, before closing adjustments, of $10.35 million. Also included among the assets acquired were interests in compression facilities and significant pipeline infrastructure.

On April 16, 2015, Kelt completed the plan of arrangement under section 193 of the ABCA involving Artek, the Corporation and the shareholders of Artek pursuant to which the Corporation acquired all of the issued and outstanding common shares of Artek on the basis of 0.34 of a Common Share for each Artek common share and Artek became a wholly-owned subsidiary of Kelt.

On April 16, 2015, immediately following the acquisition of Artek, a name change was effected to change the name of Artek Exploration Ltd. to Kelt Exploration (LNG) Ltd. ("**Kelt LNG**"), and Kelt transferred all of its British Columbia assets to Kelt LNG and at the same time, Kelt LNG transferred all of its Alberta assets to Kelt.

On April 16, 2015, immediately following the completion of the plan of arrangement with Artek, Kelt amended the Syndicated Credit Agreement by entering into an Amended and Restated Credit Agreement (the "**Amended and Restated Credit Agreement**") which increased the amount of Kelt's credit facilities to $300.0 million. The Amended and Restated Credit Agreement was amended on November 13, 2015 to reduce the amount of the credit facilities thereunder by $25.0 million to the aggregate amount of $275.0 million, with additional funds available up to the total credit facility commitment of $300.0 million subject to approval of the lending syndicate and later amended on May 31, 2016 to provide for certain amendments to its credit facility and that its borrowing base had been re-determined at $185.0 million.

Subsequent to the Arrangement, Kelt also completed several equity financings, including the completion on May 3, 2016 of a convertible debenture financing by way of a short form prospectus on a bought deal basis by completing the sale of $75.0 million principal amount of 5.0% convertible unsecured subordinated debentures (the "**Kelt Debentures**") at a price of $1,000 per Kelt Debenture. On May 3, 2015, Kelt also completed a private placement offering to certain directors, officers and employees of the Corporation, along with certain other subscribers, on a non-brokered basis, of an additional $15.0 million principal amount of Kelt Debentures at a price of $1,000 per Kelt Debenture. Net proceeds from the Kelt Debenture offerings was initially used to pay down existing bank credit facilities and thereafter, for general corporate and working capital purposes. The Kelt Debentures were listed and posted for trading on the TSX under the symbol "KEL.DB" at the open of markets on May 3, 2016.

2017

On January 18, 2017, Kelt completed the disposition of oil and gas assets located in the Karr area of Alberta ("**Karr Disposition**"). The Karr Disposition had an effective date of January 1, 2017. Kelt received gross proceeds, prior to adjustments at closing and following the waiver of certain preferential rights, in the amount of $100.0 million. The Corporation's syndicate of lenders confirmed that the authorized borrowing amount available under the Amended and Restated Credit Agreement, as amended, remained unchanged at $185.0 million.

On April 28, 2017 the Amended and Restated Credit Agreement, as amended, was further amended to, among other matters, provide for the assignment of certain commitments thereunder by certain lenders.

On October 6, 2017, Kelt announced that it had determined to complete a non-brokered private placement of 1.4 million Common Shares, to be issued on a "flow-through" share basis in respect of Canadian development expenses pursuant to the *Income Tax Act* (Canada) at a price of $7.75 per share, for gross proceeds of $11.0 million. Proceeds from the foregoing private placement were used for drilling and completion expenditures during 2017.

On October 27, 2017, Kelt increased the size of the October 6, 2017 non-brokered private placement of Common Shares, on a "flow-through" basis, in respect of Canadian development expenses, at a price of $7.75 per share, from 1.4 million Common Shares to 2.0 million, for gross proceeds of $16.1 million. Proceeds from the foregoing increase to the subject private placement were also used for drilling and completion expenditures in 2017.

On October 27, 2017, Kelt completed a non-brokered private placement of 0.6 million Common Shares, on a "flow-through" share basis in respect of Canadian exploration expenses at a price of $8.75 per share, for gross proceeds of $5.0 million. Proceeds from the foregoing private placement were used for exploration drilling and completion expenditures incurred in 2018.

On November 29, 2017, the Amended and Restated Credit Agreement, as amended, was further amended to, among other matters, provide for hedge monetizations.

2018

On March 22, 2018, Kelt entered into an agreement with Tidewater Midstream and Infrastructure Ltd. ("**Tidewater**") for firm processing of 30.0 MMcf/d of raw gas under a five year take-or-pay arrangement at Tidewater's proposed deep-cut natural gas processing plant that is expected to be constructed and on-stream by the third quarter of 2019.

On April 18, 2018, the Amended and Restated Credit Agreement, as amended, was further amended to, among other matters, provide for an increase to the borrowing base thereunder to $250.0 million.

On April 27, 2018, Kelt completed the first tranche of a non-brokered private placement of 1,469,200 Common Shares, on a "flow-through" share basis in respect of Canadian development expenses, at a price of $8.85 per share, and of 140,000 Common Shares, on a "flow-through" share basis in respect of Canadian exploration expenses, at a price of $9.75 per share for aggregate gross proceeds of $14,367,420. On April 30, 2018, Kelt completed the second tranche of a non-brokered private placement of 878,635 Common Shares, on a "flow-through" share basis in respect of Canadian development expenses, at a price of $8.85 per share, and of 270,000 Common Shares, on a "flow-through" share basis in respect of Canadian exploration expenses, at a price of $9.75 per share, for aggregate gross proceeds of $10,408,410. Proceeds from the foregoing private placements were used for drilling and completion expenditures in 2018.

On August 24, 2018 Kelt entered into agreements providing for a 10 year firm processing arrangement for 75 MMcf/d of capacity at a deep cut natural gas processing plant in Northeast B.C. that is expected to process natural gas from the Corporation's Inga/Fireweed property. Kelt has the option over the first three years of the term to commit to additional firm processing up to a maximum of 198 MMcf/d. The arrangement is expected to increase the liquids yield from the Corporation's Montney production at Inga/Fireweed. The agreements also provide for the fractionation and terminalling service for all of the C3+ and C5+ produced at the processing plant. In addition, Kelt entered into a marketing arrangement to sell its propane at Far East Index pricing, net of transportation and processing expenses.

On November 8, 2018, the Amended and Restated Credit Agreement, as amended, was further amended to, among other matters, provide for a re-allocation of the commitments of certain lenders and to provide for revised pricing.

2019

On March 29, 2019, Kelt amended and restated the Amended and Restated Credit Agreement, as amended, by entering into the Second Amended and Restated Credit Agreement (the "**Second Amended and Restated Credit Agreement**") which, among other matters, increased the amount of Kelt's credit facilities from $250.0 million to $315.0 million.

On November 7, 2019, Kelt entered into the first amending agreement to the Second Amended and Restated Credit Agreement to, among other matters, increase the amount of Kelt's credit facilities from $315.0 million to $350.0 million.

On November 8, 2019, Kelt announced that it had approved an initial capital expenditure budget of $235.0 million for 2020.

On December 20, 2019 Kelt completed a non-brokered private placement of 3,450,000 Common Shares, on a "flow-through" share basis in respect of Canadian development expenses, at a price of $5.05 per share. Proceeds from the foregoing private placement were used for drilling and completion expenditures incurred in 2019 and 2020.

Activity During Current Financial Year

On February 20, 2020, Kelt announced that amended its 2020 capital expenditures budget from $235.0 million to $225.0 million, in part to reflect the planned 2020 expenditures that were brought forward and incurred in 2019.

Significant Acquisitions

Kelt has not completed any "significant acquisitions" (as such term is defined in NI 51-102) during the financial year ended December 31, 2019.

DESCRIPTION OF THE BUSINESS

General Description of the Business

Kelt is an oil and gas company based in Calgary, Alberta, focused on the exploration, development and production of crude oil and natural gas resources, primarily in northwestern Alberta and northeastern British Columbia. Kelt's land holdings are located in four operating divisions, namely: (a) Pouce Coupe/Progress, Alberta - Kelt's Alberta development division; (b) Wembley/Pipestone, Alberta – Kelt's Alberta exploration division; (c) Inga/Fireweed, British Columbia – Kelt's B.C. development division; and (d) Oak/Flatrock, British Columbia – Kelt's B.C. exploration division. Kelt also has a number minor properties not included in the four operating divisions

Kelt was incorporated for the purposes of participating in the Arrangement and completing the Arrangement Acquisition and prior to February 26, 2013, had not carried on any active business other than in connection with the Arrangement and related matters. Since the completion of the Arrangement and the Arrangement Acquisition on February 26, 2013, Kelt has carried on the business of the exploration for, and the development and production of, oil and natural gas.

Stated Business Objective

The business plan of Kelt is to create sustainable and profitable growth as a participant in the oil and gas industry in Canada. Kelt seeks to identify and acquire strategic oil and gas properties where it believes further exploitation, development and exploration opportunities exist. In addition, Kelt has implemented a full cycle exploration program, resulting in exploration and development drilling based on opportunities generated internally.

Kelt pursues exploration plays that have low, medium and high risk and multi-zone hydrocarbon potential and strives to maintain a balance between exploration, exploitation and development drilling for oil and gas reserves, although management of Kelt also considers asset and corporate acquisition opportunities that meet its business parameters. While Kelt believes that it has the skills and resources necessary to achieve its stated objectives, participation in the exploration for and development of oil and gas has a number of inherent risks. See "*Risk Factors*" in this Annual Information Form.

Marketing

Kelt markets its crude oil, natural gas and NGLs production which is sold primarily to third party marketing companies at market prices. Crude oil contracts are generally month to month and cancellable on 30 days' notice, NGL contracts are generally for a period of up to one year and are cancellable on 90 days' notice and natural gas contracts are generally for one year. The Corporation has a combination of firm and interruptible pipeline service to deliver its production to market that range in length from 1-20 years.

Cyclical and Seasonal Nature of Industry

Kelt's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years. Global benchmark crude oil price $56.98 US$/bbl WTI during 2019. AECO 5A gas reference prices $1.76 CA$/MMBtu.

Kelt's natural gas marketing portfolio may be adjusted with an objective to maximizing its natural gas netbacks and to diversify the Corporation's price risk away from a single market. In 2019, Kelt's natural gas sales were split between the following markets: Chicago (42%); Dawn (22%), Sumas (15%), Malin (14%) and AECO/Station2 (6%).

The Corporation may enter into fixed price contracts and derivative financial instruments for commodity prices in order to secure future cash flows or to protect a desired level of capital spending See "*Risk Factors – Hedging*" in this Annual Information Form.

Such prices are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on the financial condition of Kelt. See "*Risk Factors – Prices, Markets and Marketing of Crude Oil and Natural Gas*" in this Annual Information Form.

The production of oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. See "*Risk Factors – Seasonality*" in this Annual Information Form.

Employees

As at the date of this Annual Information Form, Kelt has 52 full-time employees and 3 part-time employees located at its head office. In addition, the Corporation has 42 full time employees located at various field operational sites. To continue with the development of its assets, Kelt may require additional experienced employees and third-party consultants and contractors. See "*Risk Factors – Reliance on Key Personnel*" in this Annual Information Form.

Specialized Skill and Knowledge

Kelt believes its success is dependent on the performance of its management and key employees, many of whom have specialized knowledge and skills relating to oil and gas operations. Kelt believes that it has adequate personnel with the specialized skills required to successfully carry out its operations. See "*Risk Factors – Reliance on Key Personnel*" in this Annual Information Form.

Competitive Conditions

The oil and gas industry is highly competitive. Kelt actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas entities, many of which have significantly greater financial resources, staff and facilities than Kelt. Kelt's competitors include integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Certain of Kelt's customers and potential customers may themselves explore for oil and natural gas and the results of such exploration efforts could affect Kelt's ability to sell or supply oil or gas to these customers in the future. Kelt's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers is dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources. See "*Risk Factors – Competition*" in this Annual Information Form.

Environmental Protection

The oil and gas industry is subject to environmental regulations pursuant to applicable legislation. Such legislation provides for restrictions and prohibitions on release or emission of various substances produced in association with certain oil and gas industry operations, and requires that well and facility sites be abandoned and reclaimed to the satisfaction of environmental authorities. Kelt maintains an insurance program consistent with industry practice to protect against losses due to accidental destruction of assets, well blowouts, pollution and other operating accidents or disruptions. Kelt has established operational and emergency response procedures and safety and environmental programs to reduce potential loss exposure. No assurance can be given that the application of environmental laws to the business and operations of Kelt will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Kelt's financial condition, results of operations or prospects. See "*Risk Factors – Environmental Risks*" and "*Industry Conditions – Environmental Regulation*" in this Annual Information Form.

Social and Environmental Policies

Kelt is committed to meeting industry standards in each jurisdiction in which it operates with respect to human rights, environment, health and safety policies. Management, employees and contractors are governed by and required to comply with Kelt's environment, health and safety policy as well as all applicable federal, provincial and municipal legislation and regulations.

Kelt has established roles and responsibilities to facilitate effective management of its environment, health and safety policy throughout the organization. It is the primary responsibility of the managers, supervisors and other senior field staff of Kelt to oversee safe work practices and ensure that rules, regulations, policies and procedures are being followed.

Bankruptcy and Similar Procedures

There has been no bankruptcy, receivership or similar proceedings against Kelt, or any voluntary bankruptcy, receivership or similar proceedings by Kelt.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Petroleum and Natural Gas Reserves

Sproule, independent petroleum engineers of Calgary, Alberta, prepared the Sproule Report evaluating and auditing the proved and probable crude oil, natural gas and NGL reserves attributable to Kelt's interest in 100% of its properties and the present value of estimated future cash flow from such reserves, based on forecast price and cost assumptions. All of Kelt's reserves are in Canada, and, specifically, in Alberta and British Columbia. The reserves information was prepared and is presented in accordance with the requirements of NI 51-101.

In preparing the Sproule Report, Sproule obtained information from Kelt, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data, future operating plans and estimated abandonment and reclamation costs for Kelt's dedicated facilities. Other engineering, geological or economic data required to conduct the evaluation and audit and upon which the Sproule Report is based, was obtained from public records, other operators and from Sproule's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by Sproule as represented.

Disclosure of Reserves Data

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 are numerous uncertainties inherent in estimating quantities of crude oil, NGL and natural gas reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. The recovery and reserve estimates of the crude oil, NGL 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 NGL reserves may be greater than or less than the estimates provided herein. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of crude oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable crude oil, natural gas and NGL 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 may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with Kelt's assets may vary from the information presented herein and such variations could be material. See "*Risk Factors*" in this Annual Information Form.

The following tables, based on the Sproule Report, show the estimated share of Kelt's oil, natural gas and NGL reserves in its properties and the present value of estimated future net revenue for these reserves, after provision for Alberta gas cost allowance, using forecast price and cost assumptions. **All evaluations and audits of the present worth of estimated future net revenue in the Sproule Report are stated after provision for estimated future capital expenditures, both before and after income taxes, but prior to indirect costs, well abandonment and disconnect costs and surface lease reclamation costs or equipment salvage values and do not necessarily represent the fair market value of the reserves.**

Throughout the following summary tables differences may arise due to rounding.

In accordance with the requirements of NI 51-101, attached hereto are the following appendices:

Appendix A:	Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor in Form 51-101F2 containing certain information estimated using forecast prices and costs based on December 31, 2019 pricing assumptions
Appendix B:	Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3

Definitions used for reserve categories in the Sproule Report are attached as Appendix C hereto.

The following table summarizes Kelt's oil and gas reserves as of December 31, 2019 based on forecast price and cost assumptions.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2019
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS[1]		CONVENTIONAL NATURAL GAS[2]		NATURAL GAS LIQUIDS		TOTAL BOE	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED										
Developed Producing	5,552.0	4,638.5	34,332	31,870	129,662	117,830	15,969.7	13,500.2	48,854	43,089
Developed Non-Producing	407.0	370.6	1,932	1,815	11,980	11,079	2,118.4	1,907.3	4,844	4,427
Undeveloped	7,728.0	6,573.1	48,661	45,198	501,172	450,831	71,516.5	62,186.1	170,884	151,431
TOTAL PROVED	**13,687.0**	**11,582.2**	**84,925**	**78,883**	**642,815**	**579,741**	**89,604.6**	**77,593.6**	**224,582**	**198,947**
PROBABLE	11,402.8	9,316.2	68,428	63,655	671,773	590,211	101,629.2	85,854.2	236,399	204,148
TOTAL PROVED PLUS PROBABLE	**25,089.8**	**20,898.3**	**153,354**	**142,538**	**1,314,587**	**1,169,952**	**191,233.9**	**163,447.8**	**460,981**	**403,094**

Notes:

(1) Conventional natural gas (solution gas) includes all gas produced in association with light, medium and heavy crude oil and tight oil.

(2) Associated and non-associated gas.

The following tables summarize the undiscounted value and the present value, discounted at 5%, 10%, 15% and 20%, of Kelt's estimated future net revenue based on forecast price and cost assumptions as of December 31, 2019.

SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUE
as of December 31, 2019[1]

FORECAST PRICES AND COSTS

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNT-ED AT 10%/year
RESERVES CATEGORY	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**$/BOE**
PROVED											
Developed Producing	530,630	563,892	514,261	464,760	423,806	530,630	563,892	514,261	464,760	423,806	11.93
Developed Non-Producing	85,589	68,675	56,991	48,637	42,412	85,589	68,675	56,991	48,637	42,412	12.87
Undeveloped	3,123,243	1,966,068	1,328,413	943,014	692,482	2,428,106	1,523,641	1,022,621	719,244	521,923	8.77
TOTAL PROVED	**3,739,462**	**2,598,635**	**1,899,665**	**1,456,410**	**1,158,699**	**3,044,325**	**2,156,208**	**1,593,873**	**1,232,640**	**988,141**	**9.55**
PROBABLE	5,675,961	3,225,131	2,088,817	1,468,909	1,091,846	4,204,956	2,369,746	1,520,116	1,059,540	781,757	10.23
TOTAL PROVED PLUS PROBABLE	**9,415,423**	**5,823,766**	**3,988,482**	**2,925,319**	**2,250,545**	**7,249,281**	**4,525,954**	**3,113,989**	**2,292,180**	**1,769,898**	**9.89**

Note:

(1) Values reflect abandonment and reclamation costs for all existing wells assigned reserves and for all future locations assigned reserves in the Sproule Report as well as abandonment and reclamation costs for dedicated facilities required to produce the assigned reserves,

in the aggregate amount of $317.8 million (undiscounted) for total proved reserves and $386.1 million (undiscounted) for total proved plus probable reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2019 FORECAST PRICES AND COSTS								
RESERVES CATEGORY	**REVENUE (M$)**	**ROYALTIES (M$)**	**OPERATING COSTS (M$)**	**DEVELOP-MENT COSTS (M$)**	**ABANDON-MENT AND RECLAMA-TION COSTS (M$)**	**FUTURE NET REVENUE BEFORE INCOME TAXES (M$)**	**INCOME TAXES (M$)**	**FUTURE NET REVENUE AFTER INCOME TAXES (M$)**
Proved Reserves	9,191,537	1,012,092	2,743,279	1,378,896	317,809	3,739,462	695,136	3,044,325
Proved Plus Probable Reserves	20,174,952	2,466,304	5,452,634	2,454,447	386,144	9,415,423	2,166,142	7,249,281

FUTURE NET REVENUE BY PRODUCTION TYPE as of December 31, 2019 FORECAST PRICES AND COSTS			
RESERVES CATEGORY	**PRODUCTION TYPE**	**FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/Year) (M$)**	**UNIT VALUE BEFORE INCOME TAXES (discounted at 10%/Year) ($/BOE)**
Proved Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	323,929	10.76
	Conventional Natural Gas (including associated by-products) (1)	1,576,637	9.34
	Other items	-901	-
	Total	1,899,665	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	591,947	10.79
	Conventional Natural Gas (including associated by-products) (1)	3,397,435	9.76
	Other items	-901	-
	Total	3,988,482	

Note:

(1) Includes corporate capital gas cost allowance.

PRICING ASSUMPTIONS

Forecast Prices and Costs - December 31, 2019

Sproule employed the following pricing, exchange rate and inflation rate assumptions in estimating Kelt's reserves data using forecast prices and costs as of December 31, 2019.

FORECAST PRICES USED IN PREPARING RESERVES DATA Sproule Associates Limited Price Forecast Effective December 31, 2019							
	Light Oil		**Heavy & Medium Oil**		**Natural Gas Liquids**		
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Canadian Light Sweet Crude 40° API ($Cdn/Bbl)**	**Western Canada Select 20.5° API ($Cdn/Bbl)**	**Hardisty Bow River 24.9° API ($Cdn/Bbl)**	**Edmonton Propane ($Cdn/Bbl)**	**Edmonton Butane ($Cdn/Bbl)**	**Edmonton Pentanes Plus ($Cdn/Bbl)**
Historical							
2015	48.80	57.45	44.83	45.35	6.17	36.81	61.45
2016	43.32	52.80	38.89	39.22	13.60	34.32	55.71

FORECAST PRICES USED IN PREPARING RESERVES DATA Sproule Associates Limited Price Forecast Effective December 31, 2019							
	Light Oil		Heavy & Medium Oil		Natural Gas Liquids		
Year	WTI Cushing Oklahoma ($US/Bbl)	Canadian Light Sweet Crude 40° API ($Cdn/Bbl)	Western Canada Select 20.5° API ($Cdn/Bbl)	Hardisty Bow River 24.9° API ($Cdn/Bbl)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Edmonton Pentanes Plus ($Cdn/Bbl)
2017	50.95	61.85	50.24	50.56	28.77	44.11	67.21
2018	64.77	68.49	52.34	53.11	27.00	33.65	79.31
2019	57.02	68.87	58.77	59.10	17.16	23.71	71.39
Forecast							
2020	61.00	73.84	59.81	61.29	25.07	37.72	76.32
2021	65.00	78.51	63.98	64.77	31.84	43.90	80.52
2022	67.00	78.73	63.77	64.55	32.43	47.74	80.00
2023	68.34	80.30	65.04	65.85	33.26	48.69	81.68
2024	69.71	81.91	66.34	67.16	34.12	49.67	83.38
2025	71.10	83.54	67.67	68.51	34.99	50.66	85.13
2026	72.52	85.21	69.02	69.88	35.88	51.67	86.90
2027	73.97	86.92	70.40	71.27	36.78	52.71	88.72
2028	75.45	88.66	71.81	72.70	37.71	53.76	90.57
2029	76.96	90.43	73.25	74.15	38.65	54.84	92.45
2030	78.50	92.24	74.71	75.64	39.61	55.93	94.38
Thereafter	Escalation rate of 2.0% thereafter						

FORECAST PRICES USED IN PREPARING RESERVES DATA Sproule Associates Limited Price Forecast Effective December 31, 2019					
	Natural Gas			Operating Cost Inflation Rate (%/Yr)	Exchange Rate ($US/$Cdn)
Year	Henry Hub Price ($US/MMBtu)	Alberta AECO-C Spot ($Cdn/MMBtu)	Alliance Chicago Spot ($Cdn/MMBtu)		
Historical					
2015	2.63	2.70	3.54	1.8	0.78
2016	2.55	2.18	3.21	1.2	0.76
2017	3.02	2.19	3.69	1.7	0.77
2018	3.07	1.53	3.92	2.4	0.77
2019	2.53	1.80	3.20	(0.6)	0.75
Forecast					
2020	2.80	2.04	3.58	0.0	0.76
2021	3.00	2.27	3.80	1.0	0.77
2022	3.25	2.81	3.96	2.0	0.80
2023	3.32	2.89	4.04	2.0	0.80
2024	3.38	2.98	4.13	2.0	0.80
2025	3.45	3.06	4.21	2.0	0.80
2026	3.52	3.15	4.30	2.0	0.80
2027	3.59	3.24	4.39	2.0	0.80
2028	3.66	3.33	4.48	2.0	0.80
2029	3.73	3.42	4.57	2.0	0.80
Thereafter	Escalation rate of 2.0% thereafter				

Kelt's weighted average selling prices before financial instruments for the year ended December 31, 2019 were $66.94/Bbl for oil, $20.62/Bbl for NGLs and $3.26/Mcf for natural gas, before derivative financial instruments. See "*Additional Information Relating to Reserves Data – Netback History*" in this Annual Information Form.

RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Reserves Reconciliation

The following table sets forth a reconciliation of the total gross (before calculation of royalties and before consideration of the Corporation's royalty interests) proved, probable and proved plus probable reserves as at December 31, 2019 based on forecast price and cost assumptions.

	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL			CONVENTIONAL GAS[1]			NATURAL GAS LIQUIDS			TOTAL EQUIVALENT		
FACTORS	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**
December 31, 2018	**13,110.1**	**10,642.0**	**23,752.0**	**568,298**	**474,689**	**1,042,987**	**50,616.8**	**54,478.2**	**105,095.0**	**158,443.2**	**144,235.1**	**302,678.3**
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Extensions	740.8	525.2	1,266.0	94,555	136,954	231,509	18,880.8	25,873.6	44,754.4	35,380.7	49,224.5	84,605.2
Infill Drilling	1,975.5	1,222.1	3,197.6	84,969	121,156	206,125	16,138.7	21,552.4	37,691.1	32,275.6	42,967.2	75,242.8
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	367	148	515	35.0	14.1	49.1	96.2	38.7	134.9
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	(336.1)	10.1	(326.0)	(10,734)	1,489	(9,245)	(704.8)	(80.8)	(785.6)	(2,829.8)	177.4	(2,652.4)
Technical Revisions[2]	(200.1)	(996.5)	(1,196.6)	25,433	5765	31,198	8090.6	(208.3)	7,882.3	12,129.4	(243.9)	11,885.5
Production	(1,603.2)	0.0	(1,603.2)	(35,148)	0.0	(35,148)	(3,452.5)	0.0	(3,452.5)	(10,913.7)	0.0	(10,913.7)
December 31, 2019	**13,687.0**	**11,402,8**	**25,089.8**	**727,740**	**740,201**	**1,467,941**	**89,604.6**	**101,629.2**	**191,233.9**	**224,581.6**	**236,399.0**	**480,980.5**

Notes:

(1) Gross Reserves means the Corporation's working interest reserves before calculation of royalties, and before consideration of the Corporation's royalty interests.

(2) Technical Revisions also include changes in reserves associated with changes in operating costs, capital costs and commodity price offsets. Changes in the economic life due to a lower oil price forecast and increased operating costs resulted in a technical revision to the Light and Medium Oil reserves in the Pouce Coupe/Progress operating division. Improved well performance as well as category changes from non-producing to producing reserves and undeveloped to developed reserves in the Inga/Fireweed operating division resulted in a positive technical revision to both the conventional gas reserves and the natural gas liquids reserves.

(3) Proved component of category change probable undeveloped reserves to proved reserves have been included in the Extensions or Infill Drilling categories.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, undeveloped reserves associated with Kelt's assets are planned to be developed over the next 5 years on a proved basis and 7 years for proved and probable reserves.

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

The following tables sets forth the proved undeveloped reserves and probable undeveloped reserves, by product type, first attributed as reserves for the following financial periods and first attributed to Kelt's assets for the year ended December 31, 2019.

Proved Undeveloped Reserves

Year/Period	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL First Attributed (Mbbl)	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL Cumulative at Year End(1) (Mbbl)	CONVENTIONAL NATURAL GAS(2) First Attributed (MMcf)	CONVENTIONAL NATURAL GAS(2) Cumulative at Year End(1) (MMcf)	NATURAL GAS LIQUIDS First Attributed (Mbbl)	NATURAL GAS LIQUIDS Cumulative at Year End(1) (Mbbl)
December 31, 2017	2,297.3	5,442.0	69,528	319,620	12,488.1	33,571.2
December 31, 2018	1,991.1	6,171.0	61,061	396,218	9,131.7	38,185.0
December 31, 2019	2,446.6	7,728.0	159,430	549,833	30,866.9	71,516.5

Notes:
(1) Cumulative at year end is cumulative of previous year/period plus first attributed, less developed during the year/period.
(2) Natural gas volumes include solution gas, associated and non-associated gas.

Probable Undeveloped Reserves

Year	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL First Attributed (Mbbl)	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL Cumulative at Year End(1) (Mbbl)	CONVENTIONAL NATURAL GAS(2) First Attributed (MMcf)	CONVENTIONAL NATURAL GAS(2) Cumulative at Year End(1) (MMcf)	NATURAL GAS LIQUIDS First Attributed (Mbbl)	NATURAL GAS LIQUIDS Cumulative at Year End(1) (Mbbl)
December 31, 2017	2,294.6	6,236.9	69,042	277,187	13,136.3	33,712.6
December 31, 2018	2,900.9	8,198.3	122,385	410,142	20,542.8	48,856.0
December 31, 2019	1,838.0	9,567.4	302,330	690,753	56,654.5	96,723.3

Notes:
(1) Cumulative at year end is cumulative of previous year/period plus first attributed, less developed during the year/period.
(2) Natural gas volumes include solution gas, associated and non-associated gas.

Sproule has assigned 170,883 MBOE of proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with approximately $1,349 million of associated undiscounted future capital expenditures. Proven undeveloped capital spending in the first two forecast years of the Sproule Report accounts for approximately $447 million or 32%, of the total forecast. The remaining proven undeveloped reserves are expected to be developed within 5 years based on the Corporation's current development plans.

Sproule has assigned 221,416 MBOE of probable undeveloped reserves and has allocated additional future development capital of approximately $1,076 million to all probable undeveloped reserves with 6% scheduled for the first two years. The remaining probable undeveloped reserves are expected to be developed within 7 years based on the Corporation's current development plans.

The Corporation has a large inventory of development opportunities and its capital spending is prioritized to optimize development plans and achieve strategic goals for the Corporation. The pace of development is influenced by many factors including oil and natural gas prices, prevailing economic conditions and risks and the outcome of yearly drilling and reservoir evaluations. The Corporation's undeveloped reserves represent a large resource development which in its very nature would require several years to optimize capital allocation, facilities and surface access issues. All of the Corporation's undeveloped locations are forecast within timeframes recommended in the COGE Handbook for resource development being 7 years for proved undeveloped reserves and 10 years for probable undeveloped reserves.

Significant Factors or Uncertainties

The process of estimating reserves requires decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. Kelt's reserves are evaluated by Sproule, an independent engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. Kelt's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material. See "*Risk Factors – Reserves Estimates*" in this Annual Information Form.

Future Development Costs

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

	Undiscounted Forecast Costs	
Year	**Proved Reserves (M$)**	**Proved Plus Probable Reserves (M$)**
2020	148,717.1	163,852.1
2021	327,544.2	380,863.2
2022	336,964.6	399,951.6
2023	384,449.8	454,307.3
2024	181,219.9	450,553.7
Remaining Years	-	604,918.7
Total Undiscounted	**1,378,895.6**	**2,454,446.6**

The future development costs for both the proved and proved plus probable scenarios are expected to be funded with internally generated cash flow estimates based on the assumptions contained in the Sproule Report. On an annual basis, future capital expenditures may differ depending on management's current development plans which are dependent on many factors including current commodity prices and access to capital. For 2020, the Corporation has established a $225.0 million capital program to fund its exploration and development activities which is in excess of both the proved and proved plus probable future development costs. The 2020 capital expenditure budget includes expenditures for land, infrastructure, and exploration or delineation wells that are not contained in the reserve report.

There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributable in the Sproule Report. Failure to develop those reserves could have a negative impact on Kelt's future cash flow. The Corporation has not approved a capital program beyond 2020.

Kelt expects to fund the development costs of these reserves through a combination of the funds available from its Credit Facilities, internally generated cash flow and the issuance of new equity and/or debt where and when it believes appropriate. The Corporation's capital program does not include any new acquisition opportunities, which would likely be financed through debt or equity financings, if necessary.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. Kelt does not anticipate that interest or other funding costs would make further development of any of Kelt's assets uneconomic.

See "*Risk Factors – Substantial Capital Requirements; Liquidity*" and "*– Reserve Estimates*" in this Annual Information Form.

Other Oil and Gas Information

The following is a description of the Corporation's principal oil and gas properties, and a description of the Corporation's major plants, facilities and installations.

Oil and Gas Properties

Pouce Coupe/Progress

As at March 6, 2020, the Corporation has interests in 158,348 gross (97,315 net) acres of land in this area which is located approximately 70 kilometres north of Grande Prairie, Alberta. At Pouce Coupe/Progress, the Corporation has a 20.256% working interest in the 140 MMcf/d Progress gas plant located at 1-1-078-10W6M and a 100% working interest in a compression facility located at 6-33-77-11-W6M. At Pouce/Progress, the Corporation has targeted several different geologic formations including Montney light oil, Montney and Doig natural gas and Charlie Lake and Halfway light oil.

Wembley/Pipestone

As at March 6, 2020, the Corporation has interests in 142,560 gross (122,254 net) acres of land in this area which is located approximately 10 kilometres north of Grande Prairie, Alberta. At Wembley/Pipestone, the Corporation has an oil battery at 01-14-072-08W6M with a capacity of 3,500 bbl/d of oil and 20 MMcf/d of natural gas. The Corporation's natural gas production is processed at third party facilities, including 30 MMcf/d of processing capacity at a deep cut gas processing plant at Pipestone that was completed in September 2019. The third-party gas plant at Pipestone provides the Corporation with processing capacity for the 13 Montney wells it had drilled in Wembley/Pipestone over the past two years.

Inga/Fireweed

As at March 6, 2020, the Corporation has interests in 240,262 gross (230,730 net) acres of land in this area which is centered approximately 60 kilometres north west of Fort St. John, British Columbia. At Inga, the Corporation has a 100% working interest in a 100 MMcf/d gas, dehydration and compressor facility located at 2-10-88-23 W6. At Fireweed, the Corporation has a 100% working interest in a 16 MMcf/d compressor station located at A-16-A/094-A-13. At Inga/Fireweed, the Corporation is developing condensate rich natural gas in the Montney and Doig formations. In 2019, the Corporation drilled and completed 18 wells on a 24 well development pad with the remaining 6 wells to be completed in 2020.

Oak/Flatrock

As at March 6, 2020, the Corporation has interests in 207,567 gross (206,295 net) acres of land in this area which is located approximately 30 kilometres north east of Fort St. John, British Columbia. Oak/Flatrock is an exploration area for Kelt and as of December 31, 2019, the Corporation has 5 completed Montney wells in the area. At Oak/Flatrock, the Corporation is targeting light oil and condensate rich natural gas in the Montney formation. The Corporation has planned several exploration and delineation wells for Oak in 2020.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2019 in which Kelt has an interest.

Location	PRODUCING				NON-PRODUCING				SERVICE WELLS	
	Oil		Natural Gas		Oil		Natural Gas			
	Gross(1)	Net(2)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	271	166.3	201	95.9	144	78.4	406	210.3	60	19.6
British Columbia	12	12.0	143	138.1	30	29.8	121	94.3	7	6.0
TOTAL	283	178.3	344	234.0	174	108.2	527	304.6	67	25.6

Notes:

(1) "**Gross**" wells means the number of wells in which Kelt has a working interest or a royalty interest that may be convertible to a working interest.

(2) "**Net**" wells means the aggregate number of wells obtained by multiplying each gross well by Kelt's percentage working interest therein.

Properties with no Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by Kelt as at December 31, 2019 and the net area of unproved property for which Kelt expects its rights to explore, develop and exploit to expire during the next year.

UNPROVED PROPERTIES - UNDEVELOPED LAND (acres)			
LOCATION	**Gross(1)**	**Net(2)**	**Net Area to Expire by December 31 2020**
Alberta	283,978	208,397	5,824
British Columbia	395,876	375,668	8,578
TOTAL	679,854	584,065	14,402

Notes:

(1) "**Gross Acres**" are the total acres in which Kelt has or had an interest.

(2) "**Net Acres**" is the aggregate of the total acres in which Kelt has or had an interest multiplied by Kelt's working interest percentage held therein.

There are no costs or work commitments associated with Kelt's non-producing properties except for annual lease rental payments.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

There are no significant economic factors and uncertainties which affect the anticipated development or production activities on certain of the Corporation's properties with no attributed reserves.

Forward Contracts

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

Kelt may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. These hedging activities could expose Kelt to losses or gains. See "*Risk Factors – Hedging*" in this Annual Information Form.

Additional Information Concerning Abandonment and Reclamation Costs

Kelt estimates the total cost of future abandonment and reclamation for its existing wells, including their associated production facilities and infrastructure, and the expected timing of the costs to be incurred in future periods. The Corporation has a process for estimating these costs, which considers past experience, applicable current regulations, technology and industry standards, actual and anticipated costs, the type and depth of the well (or the nature and size of the facility), and the geographic location. Kelt expects to incur abandonment and reclamation costs on 1,395 gross (850.7 net) wells, comprising currently producing, non-producing and service wells. As at December 31, 2019, the Corporation has estimated its share of the total abandonment and reclamation costs for its existing wells and facilities to be $291.2 million undiscounted (approximately $61.6 million discounted at 10%), of which Kelt expects to pay approximately $1.1 million over the next three financial years.

The Sproule Report in 2019 included the Corporation's full estimated undiscounted future abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

Tax Horizon

At the end of 2019, Kelt had approximately $1,185 million of tax pools available. It is expected, based upon current legislation, Kelt's 2020 planned capital expenditures and various other assumptions, that no cash income taxes are to be paid by Kelt in the near future. A higher level of capital expenditures than those currently contemplated for 2020, or further additional acquisitions, could further extend the estimated tax horizon.

Income Taxes

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

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

Costs Incurred

The following table summarizes Kelt's corporate and property acquisition costs, exploration costs and development costs (before property dispositions) incurred during the year ended December 31, 2019. The amounts reported as unproved acquisition costs and exploration costs are consistent with capital expenditures classified as exploration and evaluation assets under IFRS. The amounts reported as proved acquisition costs and development costs are consistent with capital expenditures classified as property, plant and equipment under IFRS.

Acquisitions and Capital Expenditures	
Nature of cost	**Amount (M$)**
Corporate Acquisition Costs	
Proved	-
Unproved	-
Property Acquisition Costs	
Proved	214
Unproved	6,969
Exploration Costs	9,001
Development Costs	307,554
Corporate Costs	771
Total	324,509

Exploration and Development Activities

The following table sets forth the results of exploration and development activities on Kelt's assets during the year ended December 31, 2019:

Wells(1)	**Gross**	**Net**
Development		
Gas	22.0	22.0
Oil	8.0	8.0
Service	1.0	1.0
Exploratory		
Gas	2.0	2.0
Total	33.0	33.0

Note:
(1) Based on Lahee Classification System.

During 2020, Kelt expects to drill wells in three of its core operating areas, targeting liquids-rich natural gas at Inga/Fireweed and Oak/Flatrock in British Columbia, and natural gas and light oil in Wembley/Pipestone in Alberta.

Production Estimates

The following table discloses, by product type, the volume of working interest share of production estimated for Kelt's assets before the deduction of royalties for the first year for gross proved reserves and gross probable reserves as reported in the Sproule Report effective December 31, 2019, based on forecast prices and costs.

Corporation	**Light Crude Oil and Medium Crude Oil (Bbl/d)**	**Conventional Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbl/d)**	**Combined (BOE/d)**
Total Proved	3,918	103,776	13,611	34,825
Total Proved Plus Probable	4,923	119,667	16,460	41,328

The Pouce Coupe/Progress property, the Inga/Fireweed property and the Wemley/Pipestone property each account for 20% or more of the estimated production set forth in the immediately preceding tables. The following tables disclose by product type the volume of working interest share of production estimated for each of the properties before the deduction of royalties for the first year for gross proved reserves and gross probable reserves as reported in the Sproule Report effective December 31, 2019, based on forecast prices and costs.

The estimated average daily volume of production for the first year for each the Pouce Coupe/Progress property, the Inga/Fireweed property and the Wembley/Pipestone property as reported in the Sproule Report is as follows:

	Light Crude Oil and Medium Crude Oil (Bbl/d)	Conventional Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Combined (BOE/d)
Pouce Coupe/Progress				
Total Proved	1,867	28,493	721	7,337
Total Proved Plus Probable	1,964	29,617	744	7,644
Inga/Fireweed				
Total Proved	80	46,601	9,104	16,951
Total Proved Plus Probable	91	55,341	10,698	20,013
Wembley/Pipestone				
Total Proved	1,856	16,565	3,445	8,062
Total Proved Plus Probable	2,745	23,223	4,734	11,350

Production History

The following table summarizes Kelt's average daily production before deduction of royalties, for the periods indicated:

	2019				
Product	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Light & Medium Crude Oil (Bbl/d)	9,361	9,900	9,981	9,727	7,806
NGLs (Bbl/d)	4,490	4,888	4,480	4,679	3,903
Conventional Natural Gas (Mcf/d)(1)	96,658	98,844	100,136	95,450	92,089
Total (BOE/d)	29,961	31,262	31,150	30,314	27,057

Note:
(1) Sulphur volumes included in conventional natural gas.

Netback History

The following table sets forth information respecting average net product prices received, royalties paid, production expenses and operating netbacks received by the Corporation in respect of the Corporation's production of crude oil, NGLs and natural gas for the periods indicated.

	2019				
Category	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Selling prices(1), before financial instruments:					
Oil ($/Bbl)(2)	66.94	63.25	60.76	72.17	67.17
NGLs ($/Bbl)(3)	20.62	21.01	16.64	20.28	25.20
Gas ($/Mcf)(4)	3.26	2.95	2.32	2.75	5.18
Average ($/BOE)	34.53	32.64	30.83	34.96	40.64
Selling prices(1), after financial instruments:					
Oil ($/Bbl)(2)	66.78	62.64	60.76	72.17	67.17
NGLs ($/Bbl)(3)	20.62	21.01	16.64	20.28	25.20
Gas ($/Mcf)(4)	3.25	2.98	2.33	2.77	5.08
Average ($/BOE)	34.45	32.53	30.85	35.01	40.31
Royalties ($/BOE)(5)	1.76	1.25	1.60	2.25	2.01

Category	2019 Year	Q4	Q3	Q2	Q1
Transportation and selling expenses:					
Oil ($/Bbl)	4.22	2.51	4.27	6.31	3.75
NGLs ($/Bbl)	0.32	0.27	0.55	0.31	0.13
Gas ($/Mcf)	1.01	0.86	1.01	1.10	1.08
Average ($/BOE)	4.62	3.54	4.69	5.53	4.77
Production expenses(6) ($/BOE)	9.18	9.09	8.88	8.73	10.14
Operating netbacks(7) ($/BOE)	18.89	18.65	15.68	18.50	23.39

Notes:

(1) "Selling prices" include total revenue (before royalties) by product category, net of the cost of purchases, are expressed as an average per unit of production.

(2) "Oil" includes crude oil and field condensate.

(3) "NGLs" include pentane, butane, propane, and ethane.

(4) "Gas" includes natural gas and sulphur.

(5) Royalties, which are net of Crown Cost Allowances (as defined below), are expressed as an average per BOE. Crown Cost Allowances includes Gas Cost Allowance ("GCA") in Alberta and Producer Cost of Service ("PCOS") in British Columbia. Given the Corporation's gas wells often have significant associated field condensate and NGL production, the total amount of GCA and PCOS credits received relates to field condensate and NGL royalties, as well as gas royalties.

(6) Production expenses include, but are not limited to, mineral lease and surface lease rentals, property taxes and expenses related to the operation and maintenance of wells, production facilities and gathering systems. Due to the nature of Kelt's petroleum and natural gas assets being comprised of oil wells with associated gas production, and of gas wells with significant associated field condensate and NGL production, actual production expenses by product type are not readily determinable. As a result, an allocation of production expenses by product type is not meaningful.

(7) "Operating Income" is calculated by deducting the royalties, production expenses and transportation expenses from petroleum and natural gas revenue, net of the cost of purchases and after realized gains and losses on associated financial instruments. The Corporation refers to operating income expressed per unit of production as an "Operating netback".

Production Volume by Field

The following table discloses for each important field, and in total, Kelt's production volumes for the financial year ended December 31, 2019 for each product type.

Field	Light Crude Oil and Medium Crude Oil (Bbl/d)	Natural Gas Liquids (Bbl/d)	Conventional Natural Gas (Mcf/d) (1)	Combined (BOE/d)	%
Inga/Fireweed	4,706	2,899	34,914	13,423	45
Oak/Flatrock	88	57	2,249	520	2
Pouce Coupe/Progress	2,871	997	40,884	10,682	36
Wembley/Pipestone	1,574	457	8,391	3,430	11
Other	122	80	10,220	1,906	6
TOTAL	9,361	4,490	96,658	29,961	100

Note:

(1) Sulphur volumes have been converted to oil equivalence at 0.6 Lt per BOE.

RISK FACTORS

The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. The following information is a summary only of certain risk factors relating to the Corporation and should be read in conjunction with the detailed information appearing elsewhere in this Annual Information Form. Prospective investors should carefully consider the risk factors set out below and consider all other information contained in this Annual Information Form and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Volatility in the Oil and Gas Industry

Market events and conditions, including global oil and natural gas supply and demand, actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**") and non-OPEC member countries' decisions on production growth and space capacity, market volatility and disruptions, 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. These events and conditions have been a factor in the decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax and royalty changes and other environmental regulations. In addition, the difficulties to get the necessary approvals or other delays to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce the Corporation's cash flow which could result in a reduced capital expenditure budget. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future or if it is able to do it may be on unfavourable and highly dilutive terms.

In addition, the global market is also currently volatile due to the uncertainty around how severely the Coronavirus outbreak will affect global energy consumption. The global economy is reliant on the manufacturing and trade of products and the movement of people, and any slowdown in this process has a chain reaction that impacts energy consumption by both manufacturers and consumers. As a result of the outbreak's impact on the global economy, commodity prices have already declined and there may be a further weakening as the effects move through the supply chain.

Credit Facilities

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

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of Kelt. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices will result in a reduction of net production revenue. Oil and natural gas prices are expected to remain volatile in the near future in response to a variety of factors beyond the Corporation's control, including but not limited to: (i) global energy supply, production and policies, including the ability of OPEC to set and maintain production levels in order to influence prices for oil; (ii) political conditions, instability, hostilities and epidemics; (iii) global and domestic economic conditions, including currency fluctuations; (iv) the level of consumer demand, including demand for different qualities and types of crude oil and liquids and the availability and pricing of alternative fuel sources; (v) the production and storage levels of North American natural gas and crude oil and the supply and price of imported oil and liquefied natural gas; (vi) weather conditions; (vii) the proximity of reserves and resources to, and capacity of, transportation facilities and the availability of refining and fractionation capacity; (viii) the ability, considering regulation and market demand, to export oil and liquefied natural gas and NGLs from North America; (ix) the effect of world-wide energy conservation and greenhouse gas reduction measures and the price and availability of alternative fuels; and (x) government regulations, actions by the Government of Alberta including, without limitation, imposing, amending, or lifting crude oil production curtailments. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the future volume of Kelt's oil and gas production. Kelt might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Kelt's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Kelt will be in part determined by the borrowing base of Kelt. A sustained material decline in prices from historical average prices could reduce Kelt's future borrowing base, therefore reducing the bank credit available to Kelt, and could require that a portion of any existing bank debt of Kelt be repaid.

In addition to establishing markets for its oil and natural gas, Kelt must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by Kelt will be affected by numerous factors beyond its control. Kelt will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by Kelt. The ability of Kelt to market natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. Kelt will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and the management of other aspects of the oil and natural gas business. Kelt has limited direct experience in the marketing of oil and natural gas.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. After the withdrawal of the United States from the Trans-Pacific Partnership, Canada entered into the CPTPP (as defined herein) along with 10 other countries. The United States, Canada and Mexico also signed the USMCA (as defined herein) on November 30, 2018, which is intended to replace NAFTA, see "*Industry Conditions – Trade Agreements*" in this Annual Information Form. The United States has also considered the imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the government in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States 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 formal exit from the European Union on January 31, 2020 remains to be determined. Additionally, some European countries have also experienced the rise of antiestablishment political parties and public protests held against open-door immigration policies, trade and globalization. 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 third party lessees' operations, reduce their access to skilled labour and as a result, 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 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. Though the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia. In January 2020, tensions and disputes remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction.

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*Industry Conditions – Pipelines*", "*– Crude Oil and Bitumen by Rail*", "*– Trade Agreements*" and "*Climate Change Regulation*" in this Annual Information Form.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. 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 on 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 participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, completing, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards or environmental damage could greatly increase the cost of operations and various field operating conditions may adversely affect the production from successful wells. These conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations 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 and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, 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 in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs. See "*Risk Factors– Insurance*" in this Annual Information Form.

Gathering and Processing Facilities and Pipeline Systems

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

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

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other 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. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. Kelt cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on Kelt's business, financial condition, results of operations and cash flows.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach 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 foreign governments and third parties and may require Kelt to incur costs to remedy such discharge. See "*Industry Conditions – Environmental Regulation*" in this Annual Information Form. No assurance can be given that the application of environmental laws to the business and operations of Kelt will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Kelt's financial condition, results of operations or prospects.

Climate Change

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. The federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing 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 the Corporation's counterparts who operate in jurisdictions where there are less costly carbon regulations.

Adverse impacts to the Corporation's business as a result of comprehensive carbon emission legislation or regulation applied to the Corporation's business in Alberta or any jurisdiction in which the Corporation operates, may include, but are not limited to: (i) increased compliance costs; (ii) permitting delays; (iii) substantial costs to generate or purchase emission credits or allowances adding costs to the products the Corporation produces; and (iv) reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on the Corporation's business resulting in, among other things, fines, permitting delays, penalties and the suspensions of operations. See "*Industry Conditions – Climate Change Regulation*" in this Annual Information Form.

In addition to climate policy risk, the industry faces physical risks attributable to a changing climate. Climate change is expected to increase the frequency of severe weather conditions, including high winds, heavy rainfall, extreme temperatures, flooding and wildfires, which may result in damage to the Corporation's assets, disruptions in operations or transportation interruptions which may lead to increased capital expenditures or reduced revenues.

Possible Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

As part of its ongoing strategy, the Corporation may complete acquisitions of assets or other entities in the future. Achieving the benefits of completed and future acquisitions depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as 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 entities requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of any acquisitions. In addition, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

Capital Markets

Kelt, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity. As future capital expenditures will be financed out of funds generated from operations, non-core property dispositions, borrowings and possible future equity sales, Kelt's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and Kelt's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, Kelt'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 materially and adversely affected as a result.

Based on current funds available and expected funds generated from operations, Kelt believes it has sufficient funds available to fund its projected capital expenditures. However, if funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if Kelt incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for Kelt's capital expenditure plans may result in a delay in development or production on Kelt's properties.

Impact of Future Financings on Market Price

In order to finance future operations or acquisitions opportunities, the Corporation may raise funds through the issuance of Common Shares or the issuance of debt instruments or securities convertible into Common Shares. The Corporation cannot predict the size of future issuances of Common Shares or the issuance of debt instruments or other securities convertible into Common Shares or the effect, if any, that future issuances and sales of the Corporation's securities will have on the market price of the Common Shares.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*" in this Annual Information Form. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Recent regulations include the temporary oil production curtailment plan which began on January 1, 2019 announced by the Government of Alberta, see "*Industry Conditions – Production and Operation Regulations*" in this Annual Information Form.

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime 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 - Provincial Royalties and Incentives*" in this Annual Information Form.

Insurance

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

Operational Dependence

Other companies operate some of the assets in which Kelt has an interest. As a result, Kelt will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Kelt's financial performance. Kelt's return on assets operated by others will therefore depend upon a number of factors that may be outside of Kelt's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which Kelt 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 Kelt has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, Kelt may be required to satisfy such obligations and to seek recourse 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, Kelt potentially becoming subject to additional liabilities relating to such assets and Kelt having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect Kelt's financial and operational results.

Project Risks

Kelt manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Kelt's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond Kelt's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, Kelt could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Variations in Foreign Exchange Rates and Insurance Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has seen a material decrease in value against the United States dollar. Any material increases in the value of the Canadian dollar may negatively impacted Kelt's operating entities production revenues. Any increase in the future Canadian/United States exchange rates could accordingly impact the future value of Kelt's reserves as determined by independent evaluators.

To the extent that Kelt engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which Kelt may contract. An increase in interest rates could result in a significant increase in the amount Kelt pays to service debt, which could negatively impact the market price of the Common Shares.

Substantial Capital Requirements; Liquidity

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

Issuance of Debt

From time to time Kelt may finance its capital program or acquisitions partially or wholly with debt, which may increase Kelt's debt levels above industry standards. Neither Kelt's articles nor its bylaws limit the amount of indebtedness that Kelt may incur. The level of Kelt's indebtedness from time to time could impair Kelt's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise. Kelt's ability to meet its debt service obligations will depend on Kelt's future operations which are subject to prevailing industry conditions and other factors, many of which are beyond the control of Kelt. As certain of the indebtedness of Kelt bears interest at rates which fluctuate with prevailing interest rates, increases in such rates would increase Kelt's interest payment obligations and could have a material adverse effect on Kelt's financial condition and results of operations. Further, Kelt's indebtedness is secured by substantially all of Kelt's assets. In the event of a violation by Kelt of any of its loan covenants or any other default by Kelt on its obligations relating to its indebtedness, the lender could declare such indebtedness to be immediately due and payable and, in certain cases, foreclose on Kelt's assets.

Hedging

From time to time Kelt may enter into agreements to receive fixed prices on its oil and natural gas production to offset risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Kelt will not benefit from such increases. Similarly, from time to time Kelt may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar, however, if the Canadian dollar declines in value compared to the United States dollar, Kelt will not benefit from its fluctuating exchange rate. In addition, from time to time, Kelt may enter into agreements to fix the interest rate on its debt to offset the risk of higher interest expenses during a period of rising borrowing costs, however, if borrowing costs decline, Kelt will not be able to benefit from such declines.

Competition

The oil and gas industry is highly competitive. Kelt actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas entities, many of which have significantly greater financial resources, staff and facilities than Kelt. Kelt's competitors include integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Certain of Kelt's customers and potential customers may themselves explore for oil and natural gas and the results of such exploration efforts could affect Kelt's ability to sell or supply oil or gas to these customers in the future. Kelt's ability to successfully bid on and acquire additional property rights, to discover reserves to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. 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. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be materially adversely affected. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

Title

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, Kelt will conduct such title reviews in connection with its principal properties as it believes are commensurate with the value of such properties. However, no absolute assurances can be given that title defects do not exist. If title defects do exist, it is possible that Kelt may lose all or a portion of its right title and interest in and to the properties to which the title defects relate.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and cash flows to be derived therefrom, including many factors beyond Kelt's control. The information concerning reserves and associated cash flow set forth in this Annual Information Form represents estimates only. In general, estimates of economically recoverable oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil, natural gas and NGL, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil, natural gas and NGL reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Kelt's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

In accordance with applicable securities laws, Sproule has used forecast price and cost estimates in calculating reserve quantities. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the Sproule Report, and such variations could be material. The Sproule Report is based in part on the assumed success of activities Kelt intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the Sproule Report will be reduced to the extent that such activities do not achieve the level of success assumed in the Sproule Report.

The Sproule Report is effective as of a specific effective date and has not been updated and thus does not reflect changes in Kelt's reserves since that date.

Reserve Replacement

Kelt's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on Kelt successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Kelt may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Kelt's reserves will depend not only on Kelt's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Kelt's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Reliance on Key Personnel

Kelt's future success depends in large measure on certain key personnel. The exploration for, and the development and production of, oil and natural gas with respect to its assets requires experienced executive and management personnel and operational employees and contractors with expertise in a wide range of areas. There can be no assurance that all of the required employees and contractors with the necessary expertise will be available. Further, the loss of any key personnel may have a material adverse effect on Kelt's business, financial condition, results of operations and prospects. Kelt currently does not have any "key man" insurance in place.

Any inability on the part of Kelt to attract and retain qualified personnel may delay or interrupt the exploration for, and development and production of, oil and natural gas with respect to Kelt's assets. Sustained delays or interruptions could have a material adverse effect on the financial condition and performance of Kelt. In addition, rising personnel costs would adversely impact the costs associated with the exploration for, and development and production of, oil and natural gas in respect of Kelt's assets, which could be significant and material.

Management of Growth

Kelt may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Kelt to manage growth effectively will require it to continue to implement and improve its operations and financial systems and to expand, train and manage its employee base. The inability of Kelt to deal with this growth could have a material adverse impact on its business, operations and prospects.

Permits and Licenses

The operations of Kelt may require licenses and permits from various governmental authorities. There can be no assurance that Kelt will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects. Further, 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 licenses or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Liability Management

Alberta and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of Kelt's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system may prevent or interfere with Kelt's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and 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. See "*Industry Conditions - Liability Management Rating Programs*" in the Annual Information Form.

Access Restrictions

The Corporation's business depends in part upon the ability to access its lands to operate, as well as the availability, proximity, and capacity of oil and natural gas gathering systems, pipelines and/or rail transportation systems and processing facilities to provide access to markets for its production. Federal and provincial, regulation of oil and natural gas production and processing and transportation could adversely affect the Corporation's ability to produce and market oil, natural gas and NGLs. Special interest groups could prevent access to leased land or oppose infrastructure development, resulting in operational delays, or even cancellation of construction of the required infrastructure, both of which frustrate the Corporation's ability to operate, produce and market its products or restrict shipping of commodities by truck, pipeline or rail.

Availability of Drilling Equipment

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Kelt and may delay exploration and development activities.

Indigenous Claims

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.

Global Financial Markets

Market events and conditions, including disruptions in the international credit markets and other financial systems, and the deterioration of global economic conditions caused significant volatility to commodity prices over the last few years. These conditions have resulted in a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and may continue to impact the performance of the global economy going forward.

If the economic climate in the U.S. or the world generally deteriorates further, demand for petroleum products could diminish further and prices for oil and natural gas could decrease further, which could adversely impact Kelt's results of operations, liquidity and financial condition.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. There can be no assurance that these seasonal factors will not adversely affect the timing and scope of Kelt's exploration and development activities, which could in turn have a material adverse impact on Kelt's business, operations and prospects.

Third Party Credit Risk

Kelt is, or may be exposed to, third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to Kelt, such failures could have a material adverse effect on Kelt and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Kelt's ongoing capital program, potentially delaying the program and the results of such program until Kelt finds a suitable alternative partner.

Hydraulic Fracturing

Concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including water aquifer contamination and other qualitative and quantitative effects on water resources as large quantities of water are used and injected fluids either remain underground or flow back to the surface to be collected, treated and disposed of. Regulatory authorities in certain jurisdictions have announced initiatives in response to such concerns. Federal, provincial and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, and adversely affect Kelt's production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay, increased operating costs, and third-party or governmental claims. They could also increase Kelt's costs of compliance and doing business as well as delay the development of hydrocarbon (natural gas and oil) resources from shale formations, which may not be commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Kelt is ultimately able to produce from its reserves.

In the event federal, provincial, local, or municipal legal restrictions are adopted in areas where Kelt is currently conducting, or in the future plan to conduct operations, Kelt may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes more regulated, Kelt's fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that Kelt is ultimately able to produce from its reserves.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by Kelt is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of Kelt's net production revenue.

In addition, Kelt's expected oil and natural gas properties, wells and facilities could be subject to a terrorist attack. As the oil and gas industry in Canada is a key supplier of energy to the United States, certain terrorist groups may target Canadian oil and gas properties, wells and facilities in an effort to choke the United States economy. If any of Kelt's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on Kelt. Kelt does not have insurance to protect against the risk from terrorism.

Tax Horizon

It is expected, based upon current legislation, the projections contained in the Sproule Report and various other assumptions that no cash income taxes are to be paid by Kelt in the near future. If a lower level of capital expenditures than those contained in the Sproule Report is incurred or, should the assumptions used by Kelt prove to be inaccurate, Kelt may be required to pay cash income taxes sooner than anticipated, which will reduce cash flow available to Kelt.

Potential Conflicts of Interest

There may be circumstances in which the interests of Kelt and its affiliates will conflict with those of shareholders. Kelt and its affiliates may acquire oil and natural gas properties on their own behalf or on behalf of persons other than the shareholders. Neither Kelt, nor its management, will carry on their full-time activity on behalf of shareholders and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of shareholders.

In the event of such conflicts, decisions will be made on a basis consistent with the provisions of any relevant contractual arrangements and objectives and financial resources of each group of interested parties. Kelt will use all reasonable efforts to resolve such conflicts of interest in a manner which will treat Kelt, and the other interested party, fairly taking into account all of the circumstances of Kelt and such interested party and to act honestly and in good faith in resolving such matters.

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

Certain directors of Kelt are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "*Directors and Officers – Conflicts of Interest*" in this Annual Information Form.

Internal Controls

Effective internal controls are necessary for Kelt to provide reliable financial reports and to help prevent fraud. Although Kelt will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, Kelt cannot be certain that such measures will ensure that Kelt will maintain adequate control over financial processes and reporting.

Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm Kelt's results of operations or cause it to fail to meet its reporting obligations. If Kelt or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in Kelt financial statements and harm the trading price of the Common Shares.

Dividends

To date, Kelt has not paid any dividends on its Common Shares and does not anticipate the payment of any dividends on its Common Shares for the foreseeable future, though it is a possibility that the Corporation may pay dividends in the future if it has started generating sufficient positive cash flow. Any future determination to pay dividends will be at the discretion of the Board and will depend on the financial condition, business environment, operating results, capital requirements, any contractual restrictions on the payment of dividends and any other factors that the Board deems relevant.

Dilution

Kelt may make future acquisitions or enter into financings or other transactions involving the issuance of securities of Kelt which may be dilutive. Common Shares, including rights, warrants, special warrants, subscription receipts and other securities to purchase, to convert into or to exchange into Common Shares, may be created, issued, sold and delivered on such terms and conditions and at such times as the Board of Directors may determine. In addition, the Corporation may issue additional Common Shares from time to time pursuant to the Corporation's stock option plan or restricted share unit plan. The issuance of these Common Shares would result in dilution to holders of Common Shares.

Litigation

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, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are 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.

Volatility of Market Price of Common Shares

The market price of the Common Shares may be volatile. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Market price fluctuations in the Common Shares may be due to the Corporation's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "*Forward-Looking Statements and Information*" in this Annual Information Form. In addition, the market price for securities in the stock markets, including the TSX, has recently experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that are often unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares.

Information Technology Systems and Cyber-Security

The Corporation relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data, compromise confidential customer or employee information, result in the disruption of business, theft or extortion of funds, regulatory infractions, loss of competitive advantage and reputational damage. In addition, information systems could be damaged or interrupted by natural disasters, force majeure events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical and/or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on the Corporation's business, financial condition, results of operations and cash flows.

In the ordinary course of business, the Corporation collects, uses and stores sensitive data, including intellectual property, proprietary business information and personal information of the Corporation's employees and third parties. Despite the Corporation's security measures, its information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions. Any such breach could compromise information used or stored on the Corporation's systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen.

To date the Corporation has not experienced any material losses relating to cyber-attacks or other information security breaches. However, there can be no assurance that the Corporation will not incur such losses in the future. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties or other negative consequences, including disruption to the Corporation's operations and damage to its reputation, which could have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows. Although the Corporation maintains a risk management program, which includes an insurance component that may provide coverage for the operational impacts from an attack to, or breach of, Kelt's information technology and infrastructure, including process control systems, the Corporation does not maintain stand-alone cyber insurance. Furthermore, not all cyber risks are insurable. As a result, Kelt's existing insurance may not provide adequate coverage for losses stemming from a cyber-attack to, or breach of, its information technology and infrastructure.

Reputation Risk

The Corporation relies on its reputation to build and maintain positive relationships with stakeholders, to recruit and retain staff, and to be a credible trusted company. Any actions that Kelt takes that causes a negative public opinion has the potential to negatively impact the Corporation's reputation which may adversely impact its share price, development plans or its ability to continue operations.

Forward-Looking Statements and Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking statements and information. By its nature, forward-looking statements and information involve numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties related to forward-looking statements and information are found under the heading "*Forward-Looking Statements and Information*" in this Annual Information Form.

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and British Columbia, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of Kelt in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and Kelt is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in the provinces of Alberta and British Columbia.

Pricing and Marketing – Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the availability and cost of transportation capacity to various markets, value of refined products, the supply/demand balance and contractual terms of sale.

Pricing and Marketing – Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short-term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

Pricing and Marketing – Natural Gas Liquids

In Canada, the price of NGL sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGL, prices of competing chemical feedstock, distance to market, access to downstream transportation, length of contract term, the 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 NEB with the CER. The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGL 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. See "*Industry Conditions - Environmental Regulation – Federal*" in this Annual Information Form.

Exports of crude oil, natural gas and NGL 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 NGL 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. NGL), 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 NGL. 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 license, 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 NGL) 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.

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.

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 at a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty may 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 from 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 Federal 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 National Energy Board's (the "**NEB**") environmental assessment and the Federal Government's indigenous consultations. The court quashed the accompanying certificate of public convenience and necessity and directed the Federal 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 Canadian Energy Regulator (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 the Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019. On March 5, 2020 Canada's Supreme Court dismissed five separate application of appeals relating to the Trans Mountain Pipeline expansion.

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 to impose a permitting requirement on carriers of heavy crude oil within British Columbia. The British Columbia Court of Appeal answered the reference questions 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 unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal.

While it was expected that construction on the Keystone XL Pipeline would commence in the first half of 2019, pre-construction work was halted in late 2018 when a U.S. 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 Corporation 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 dependent 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.

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 crude oil or diluted bitumen, would be subject to reduced speed limits following two derailments that led to fires and oil spills in Saskatchewan.

Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain 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 the party maintaining the restriction 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.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

On November 30, 2018, Canada, the United States and Mexico signed the United States-Mexico-Canada Agreement ("**USMCA**"). Once ratified, the USMCA will replace NAFTA. Under the USMCA, energy export restrictions are no longer subject to the requirement that they do not reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period. In addition, the USMCA includes a change to the rules of origin for crude oil that should make it easier for exporters to qualify for duty-free treatment on shipments to other USMCA parties. In particular, the origin of the diluent that is used to facilitate the transportation of crude petroleum oils is disregarded, provided that the diluent constitutes no more than 40 per cent by volume of the goods.

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 oil and gas products to the European Union. Although CETA remains subject to ratification by certain 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. In addition, Canada and ten other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**") on March 8, 2018. The CPTPP has been ratified by seven countries, including Canada.

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

Extractive Sector Transparency Measures Act

The *Extractive Sector Transparency Measures Act* (Canada) ("**ESTMA**"), a federal regime for the mandatory reporting of payments to government, came into force on June 1, 2015. ESTMA contains broad reporting obligations with respect to payments to governments and state owned entities, including employees and public office holders, made by Canadian businesses involved in resource extraction. Under ESTMA, all payments made to payees (broadly defined to include any government or state owned enterprise) must be reported annually if the aggregate of all payments in a particular category to a particular payee exceeds $100,000 per financial year. The categories of payments include taxes, royalties, fees, bonuses, dividends and infrastructure improvement payments. Failure to comply with the reporting obligations under ESTMA is punishable upon summary conviction with a fine of up to $250,000. In addition, each day that passes prior to a non-compliant report being corrected forms a new offence, and therefore, a payment that goes unreported for a year could result in over $9.0 million in total liability.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, NGL, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands 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 governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

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

Alberta

On January 1, 2017, the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**") took effect. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. 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 MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, the equivalent of 194m^3 (40 BOE/d or 345,500m^3 of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008)* and the "Alberta Royalty Framework" until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime was is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 36%. Royalties on NGLs are levied at a flat rate of 30% of the sales volume for propane and butane and 40% for pentanes plus with field condensate at a rate equivalent to oil.

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

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral taxes. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources. These initiatives apply to wells drilled before January 1, 2017 for a 10 year period until January 1, 2027. Specifically:

- coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, which came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources, respectively, in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the AER.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare for licences and $7.50 per hectare for leases, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("**old oil**"), between October 31, 1975 and June 1, 1998 ("**new**

oil"), or after June 1, 1998 or through an Enhanced Oil Recovery ("**EOR**") scheme ("**third-tier oil**"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to oil production on Crown land. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The freehold production tax rate for natural gas liquids is a flat 12.25%.

As of January 1, 2017, all liquid natural gas ("**LNG**") facilities are subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's natural gas low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs that relate to location specific factors. Effective April 1, 2014, the Deep Well Royalty Credit Program will have two tiers – "tier one" and "tier two". The existing Deep Royalty Credit Program, as described above, will comprise tier two of the program which offers a higher maximum royalty credit and attracts a 3% minimum royalty. Tier one of the Deep Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than 1,900 metres if spud on or after April 1, 2014 and attracts a 6% minimum royalty.

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date subsequent to December 1, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres.

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation.

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land.

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m^3.

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m^3. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program.

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month. The amended regulation will be applied to royalties starting with the April 2013 production month. The 3% minimum royalty began showing on monthly gas royalty invoices starting in July 2013.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce 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. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and British Columbia has 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 license. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or intermediate term of the license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operations of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, Kelt 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 with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

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 oil producers producing more than 20,000 bbl/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. The first curtailment order took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbl/d - a reduction of approximately 8.7% of total daily average oil production in Alberta during December 2018. 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, January 2020 and February 2020 is set at 3.81 million bbl/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.

Environmental Regulation

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

Federal

On a Federal level and pursuant to the *Prosperity Act* (Canada), the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the environmental legislation under the *Prosperity Act* (Canada) are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

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 Impact Assessment Agency of Canada (the "**IA Agency**") replaced the Canadian Environmental Assessment Agency (the "**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 IA 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 75 kilometres of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

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

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* 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. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures 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 Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is 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. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method 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 Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF 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 region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into effect on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 per cent of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and recreation areas will include a restriction that prohibits surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44 percent of the province's population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Phase 1 of the North Saskatchewan Region Plan ("**NSRP**") has been completed. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in British Columbia. 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 oil and 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 an oil and 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, and 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 Regulati*on, 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 *Environmental Management Act* that would see new heavy 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 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 Trans Mountain Pipeline.

The extent and magnitude of any adverse impacts of changes to the legislation or policies on project development and operations cannot be estimated at this time as uncertainty exists with respect to recommendations being considered or to be developed. Increased environmental assessment obligations or transportation restrictions may create risk of increased costs and project development delays.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Oil and Gas Conservation Act* (Alberta) establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licencees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

The AER previously assessed the lability management rating ("**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.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed assets to deemed liabilities under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced 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 was 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.

As a result of the bankruptcy court ruling in the case of Redwater Energy Corporation ("**Redwater**") which was affirmed by the Alberta Court of Appeal whereby the court found that receivers and trustees of AER licensees may selectively disclaim unprofitable assets (and their associated abandonment and reclamation obligations) under section 14.06 of the federal *Bankruptcy and Insolvency Act*, on June 20, 2016, the AER issued Bulletin 2016-16 *Licensee Eligibility – Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 16**") which includes an interim rule that as a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management ratio ("**LMR**") of 2.0 or higher immediately following the transfer. If the transfer of the licensee does not improve the purchaser's LMR to 2.0 (or higher), the purchaser can post a security deposit, address existing abandonment obligations or transfer additional assets.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued Bulletin 2016-21: *Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 21**") on July 8, 2016 and reaffirmed its position that a LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if: (i) the licensee already has a LMR of 2.0 or higher; (ii) the acquisition will improve the licensee's LMR to 2.0 or higher; or (iii) the licensee is able to satisfy its obligations, notwithstanding a LMR below 2.0, by other means. The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement.

The AER's Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals, which deals with licence eligibility to operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have been subject to insolvency proceedings in the last five years.

On January 31, 2019, the Supreme Court of Canada released its decision in the case of Redwater. Reversing the lower court decisions, the Supreme Court of Canada held that the AER may use the provincial legislative scheme to prevent a trustee in bankruptcy from renouncing a debtor's uneconomic oil and gas assets and require a trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors. While it is not yet clear how market participants will respond to the Supreme Court of Canada's decision in Redwater, the decision is anticipated to reduce the availability and increase the cost of credit for borrowers with relatively high levels of abandonment and reclamation obligations within their asset bases, thereby negatively affecting the financial capacity of such borrowers, including potential counterparties to the Corporation, result in additional or more stringent abandonment and reclamation related covenants being imposed on borrowers, and result in increased scrutiny of oil and gas assets and associated abandonment and reclamation liabilities.

British Columbia

In British Columbia, the BC Commission implements the Liability Management Rating Program (the "**BC LMR Program**"), designed to manage public liability exposure related to oil and 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 will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

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.

Climate Change Regulation

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 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 carbon-pricing regime took effect in Alberta on January 1, 2020. Alberta, Saskatchewan, and Ontario challenged the constitutionality of the federal government's pricing regime. The reference in Alberta remains before the Alberta Court of Appeal, but the Saskatchewan and Ontario references have advanced in parallel where the appeal Courts ruled in favour of the constitutionality of the federal carbon tax. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada. The Court is set to hear the appeals in March of 2020. Ontario and Saskatchewan will cross-intervene in the appeals, along with the Attorneys General of Quebec, New Brunswick, Manitoba, British Columbia, and Alberta, who will intervene in both proceedings.

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 industry, 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.

To complement carbon pricing, a Clean Fuel Standard with the objective of achieving annual reductions of 30 Mt of GHG emissions by 2030 is being developed by the federal government. The standard would require reductions in the carbon footprint of the fuels supplied in Canada, based on life cycle analysis. The approach will not differentiate between crude oil types produced in or imported into Canada. This standard is expected to apply to a broad suite of fuels used in transportation, industry, homes and buildings.

In general, there is uncertainty with regard to the impact of federal or provincial climate change and environmental laws and regulations, as 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 Kelt's operations and cash flow.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the Specified Gas Emitters Regulation ("**SGER**"), which applies to facilities emitting more than 100,000 tonnes of GHG emissions.

On January 1, 2018, the SGER was replaced with the *Carbon Competitiveness Incentive Regulation* (the "**CCIR**"), with a three-year phase-in period. Similar to the SGER, the CCIR applies to facilities emitting more than 100,000 tonnes per annum. The CCIR is designed to incent CCIR facilities to reduce GHG emissions through improving performance by establishing product-based performance standards (also called output-based allocations) across all industries. The 2019 carbon levy will remain at $30/tonne.

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. In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The 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 to industrywide 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 is 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 over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. 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

British Columbia enacted a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. 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. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On January 1, 2016, the *Greenhouse Gas Industrial Reporting and Control Act* (the "**GGIRCA**") and its associated regulations that came into force. The GGIRCA sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures.

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80% reduction in emissions from 2007 levels.

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.

DIVIDEND POLICY

There are no restrictions in Kelt's articles or elsewhere which could prevent Kelt from paying dividends. It is not currently contemplated that any dividends will be paid on any shares of Kelt in the immediate future, as it is anticipated that all available funds will be invested to finance the growth of Kelt's business. The Board of Directors will determine if, and when, dividends will be declared and paid in the future from funds properly applicable to the payment of dividends based on Kelt's financial position at the relevant time. Any decision to pay dividends on any shares of Kelt will be made by the Board of Directors on the basis of Kelt's earnings, financial requirements and other factors existing at such future time, including, but not limited to, commodity prices, production levels, capital expenditure requirements, debt service requirements, if any, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

DESCRIPTION OF SHARE CAPITAL

Kelt is authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares, of which 187,793,857 Common Shares and no Preferred Shares are issued and outstanding as at the date of this Annual Information Form. See "*Prior Sales*" in this Annual Information Form.

The following is a description of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares.

Common Shares

The holders of Common Shares are entitled to receive notice of and to attend at and to vote one vote per Common Share at meetings of shareholders, to receive dividends declared on the Common Shares, subject to the rights of the holders of shares ranking prior to the Common Shares and to receive *pro rata* the remaining property upon dissolution in equal rank with the holders of other Common Shares.

Preferred Shares

The Preferred Shares may be issued from time to time in one or more series, each series consisting of a number of Preferred Shares as determined by the Board of Directors who may also fix the designations, rights, privileges, restrictions and conditions attaching to the shares of each series of Preferred Shares. The Preferred Shares of each series shall, with respect to payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of Kelt, whether voluntary or involuntary, or any other distribution of the assets of Kelt among its shareholders for the purpose of winding-up its affairs, rank equally with the Preferred Shares of every other series and shall be entitled to preference over the Common Shares, and the shares of any other class ranking junior to the Preferred Shares.

MARKET FOR SECURITIES

Trading Price and Volume

The following table sets forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares of Kelt on the TSX as reported by sources Kelt believes to be reliable for the periods indicated:

Date	Price Range ($)		Trading Volume
	High	Low	
2019			
January	5.150	4.440	28,739,252
February	5.580	4.090	21,606,935
March	6.090	4.960	16,950,503
April	6.140	5.240	18,136,838
May	5.620	4.360	16,321,939
June	4.580	3.770	25,094,651
July	4.180	3.510	15,790,012
August	4.150	2.450	23,694,923
September	3.850	2.760	30,740,261
October	3.500	2.830	10,673,454
November	4.070	2.890	14,764,380
December	4.930	3.705	15,389,830
2020			
January	4.995	3.720	16,780,871
February	3.980	2.870	18,213,103
March 1-6	3.320	2.570	4,897,681

The following table sets forth the reported high and low sales prices (which are not necessarily the closing prices) and the trading volume for the Kelt Debentures on the TSX as reported by sources Kelt believes to be reliable for the periods indicated:

Date	Price Range ($)		Trading Volume
	High	Low	
2019			
January	118.24	105.00	2,870
February	122.00	110.01	870
March	132.00	121.00	4,610
April	127.00	124.00	2,440
May	118.00	115.00	1,710
June	115.00	108.00	970
July	111.50	105.50	19,250
August	108.79	98.15	26,640
September	105.00	101.00	21,650
October	103.00	102.01	41,820
November	104.65	102.03	7,540
December	114.00	104.37	6,070
2020			
January	112.75	103.51	4,300
February	107.83	100.00	5,020
March 1-6	101.03	100.12	4,240

PRIOR SALES

The following table sets forth, for each class of securities of the Corporation that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the financial year ended December 31, 2019 and the number of securities of the class issued at that price and the date on which the securities were issued.

Class of Securities	Issue Price or Exercise Price $	Number of Securities Issued	Date of Issue
Options	4.95	35,000	January 10, 2019
Options	5.18	17,000	March 12, 2019
RSUs	N/A	6,000	March 12, 2019
Options	5.79	8,500	March 27, 2019
RSUs	N/A	3,000	March 27, 2019
RSUs	N/A	3,000	April 15, 2019
Options	5.90	8,500	April 15, 2019
RSUs	N/A	1,200	May 21, 2019
Options	5.47	7,000	May 21, 2019
RSUs	N/A	12,000	July 2, 2019
Options	4.03	60,000	July 2, 2019
RSUs	N/A	53,000	August 19, 2019
Options	2.76	2,015,500	August 19, 2019
RSUs	N/A	10,000	September 3, 2019
Options	2.77	31,500	September 3, 2019
RSUs	N/A	10,000	October 16, 2019
Options	3.01	30,000	October 16, 2019
RSUs	N/A	6,000	November 18, 2019
Options	3.42	17,000	November 18, 2019
RSUs	N/A	10,000	November 28, 2019
Options	3.93	25,000	November 28, 2019
RSUs	N/A	30,000	December 3, 2019
Options	3.87	50,000	December 3, 2019

As at the date of this Annual Information Form, the Corporation has 10,021,401 Options and 864,350 RSUs outstanding.

ESCROWED SECURITIES

As at the date of this Annual Information Form, to the knowledge of the Corporation, no securities of any class of Kelt are held in escrow or are subject to a contractual restriction on transfer.

DIRECTORS AND OFFICERS

The following table provides the name, province and country of residence, positions held with Kelt and principal occupation during the preceding five years of each of the current directors and executive officers of Kelt.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer	Principal Occupation During the Past 5 Years
Robert J. Dales(1)(2)(4)(6) Alberta, Canada	Director since October 22, 2012	President of Valhalla Ventures Inc., a private Alberta investment corporation, from January 1999 to the present.
Douglas J. Errico Alberta, Canada	Vice President, Land since October 22, 2012	Vice President, Land of Kelt. Prior thereto, Landman and then Senior Landman with Celtic from September 2005 to February 2013.
Alan G. Franks Alberta, Canada	Vice President, Production since October 22, 2012	Vice President, Production of Kelt. Prior thereto, Vice President, Operations of Celtic from December 2002 to February 2013.
David Gillis Alberta, Canada	Vice President, Finance since April, 2018	Vice President, Finance of Kelt. Prior thereto, Executive Vice President and Chief Financial Officer of Cequence Energy Ltd. Prior thereto, Vice President, Finance and Chief Financial Officer of Cequence Energy Ltd. from July 2009 to March 2017.

Name, Province and Country of Residence	Offices Held and Time as Director or Officer	Principal Occupation During the Past 5 Years
Bruce D. Gigg Alberta, Canada	Vice President, Engineering since March 11, 2016	Vice President, Engineering of Kelt. Prior thereto, President of Giggajoule Energy Inc. from October 2014 to March 2016. Prior thereto Team Lead at NuVista Energy Ltd. from April 2005 to October 2014.
Geraldine L. Greenall(1)(4)(5) Alberta, Canada	Director since December 14, 2017	Chief Financial Officer of Spartan Delta Corp., a publicly listed exploration and production corporation. Prior thereto, Chief Financial Officer of Camber Capital Corp. (formerly Kyklopes Capital Management Ltd.), an investment management corporation, from May 2011 to December 2019.
William C. Guinan(3)(7) Alberta, Canada	Corporate Secretary and Director since October 22, 2012	Partner with Borden Ladner Gervais LLP.
Sadiq H. Lalani(8) Alberta, Canada	Vice President and Chief Financial Officer since October 22, 2012	Vice President and Chief Financial Officer of Kelt. Prior thereto, Vice President, Finance and Chief Financial Officer of Celtic from October 2002 to February 2013.
Douglas O. MacArthur Alberta, Canada	Vice President, Operations since October 22, 2012	Vice President, Operations of Kelt. Prior thereto, Operations Manager with Celtic from January 2007 to February 2013.
Patrick W.G. Miles Alberta, Canada	Vice President, Exploration since October 22, 2012	Vice President, Exploration of Kelt. Prior thereto, Geology Consultant with Celtic from November 2009 to February 2013.
Michael R. Shea(2)(4)(5) Alberta, Canada	Director since April 18, 2018	Retired Businessman since February 2013.
Neil G. Sinclair(1)(2)(3)(5) British Columbia, Canada	Director since October 22, 2012	President of Sinson Investments Ltd., a private British Columbia corporation engaged in property development, from 1973 to the present.
Carol Van Brunschot Alberta, Canada	Vice President, Marketing since July 1, 2018.	Vice President, Marketing of Kelt. Prior thereto, Manager, Marketing of Kelt from August 2016 to July 2018. Prior thereto President of 1912420 Alberta Ltd. from May 2014 to July 2016. Prior thereto, Director of Producer Services at BP Canada.
David J. Wilson(3) Alberta, Canada	President, Chief Executive Officer and Director since October 11, 2012	President and Chief Executive Officer of Kelt. Prior thereto, President and Chief Executive Officer of Celtic from September 2002 to February 2013.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Health, Safety and Environment Committee.
(4) Member of the Reserves Committee.
(5) Member of the Nominating Committee.
(6) Lead Director.
(7) Board Chair.
(8) On March 11, 2016 Mr. Lalani resigned as Vice President, Finance and was appointed Vice President of Kelt and at all times since October 22, 2012 Mr. Lalani has held the position of Chief Financial Officer of Kelt.

Each of the directors of Kelt will hold office until the first annual meeting of the holders of Common Shares or until his successor is duly elected or appointed, unless his office is earlier vacated in accordance with Kelt's articles or by-laws.

As at the date of this Annual Information Form, the current directors and officers of Kelt, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 27,506,655 Common Shares, representing approximately 14% of the issued and outstanding Common Shares and they hold 11,766 Kelt Debentures representing approximately 13% of the Kelt Debentures. The information as to the number of Common Shares beneficially owned, or controlled or directed, not being within the knowledge of the Corporation, has been furnished by the respective directors and officers of the Corporation individually.

Corporate Cease Trade Orders

None of the directors or executive officers of Kelt is or has been, within the 10 years prior to the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Kelt) that: (i) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than 30 consecutive days, 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 a director, chief executive officer or chief financial officer.

Bankruptcies

None of the directors, executive officers or securityholders holding a sufficient number of securities of Kelt to affect materially the control of Kelt is or has, within the 10 years prior to the date of this Annual Information Form, been a director or executive officer of any company (including Kelt) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal 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.

In addition, none of the directors, executive officers or securityholders holding a sufficient number of securities of Kelt to affect materially the control of Kelt has, within the 10 years prior to 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 securityholder.

Penalties or Sanctions

None of the directors, executive officers or securityholders holding a sufficient number of securities of Kelt to affect materially the control of Kelt has been subject to: (i) 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 (ii) 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 Kelt may become subject in connection with the operations of Kelt. In particular, certain directors and officers of Kelt are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Kelt or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Kelt. 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. As at the date of this Annual Information Form, Kelt is not aware of any existing or potential material conflicts of interest between Kelt and any director or officer of Kelt.

AUDIT COMMITTEE

Pursuant to NI 52-110, the Corporation is required to include in its Annual Information Form the disclosure required under Form 52-110F1 – *Audit Committee Information Required in an AIF* with respect to its audit committee, including the text of its audit committee charter, the composition of the audit committee and the fees paid to the external auditor. This information is provided in Appendix D attached hereto.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Since the date of incorporation of Kelt, there have been no legal proceedings to which the Corporation is or was a party to, or that any of the Corporation's property is or was the subject of, which is or was, or can be reasonably considered to be, material to the Corporation or any of its properties and the Corporation is not aware of any such legal proceedings that are contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" by the Corporation if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of the Corporation's current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, the Corporation has included the amount involved in the other proceedings in computing the percentage.

Since the date of incorporation of Kelt, there have been no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Corporation, and the Corporation has not entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the directors or executive officers of Kelt or any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares, or any associate or affiliate of any of the foregoing persons or companies, has or has had any material interest, direct or indirect, in any past transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect Kelt.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Odyssey Trust Company. The Common Shares are transferable at the offices of Odyssey Trust Company in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there are no material contracts entered into by Kelt since its incorporation and still in effect as at the date hereof that can be reasonably regarded as presently material.

INTERESTS OF EXPERTS

Sproule prepared the Sproule Report. The principals of Sproule own, directly or indirectly, less than 1% of the outstanding Common Shares as at the date of this Annual Information Form. Sproule neither received nor will receive any interest, direct or indirect, in any securities or other property of Kelt or its affiliates in connection with the preparation of the Sproule Report.

PricewaterhouseCoopers LLP, Chartered Professional Accountants, are the auditors of Kelt and have confirmed that they are independent with respect to Kelt in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta. PricewaterhouseCoopers LLP, Chartered Professional Accountants, were appointed the auditors of the Corporation on October 11, 2012.

ADDITIONAL INFORMATION

Additional information relating to the Corporation, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, will be contained in the Corporation's Management Information Circular which relates to the Annual Meeting of Shareholders to be held on April 22, 2020 and which will be filed on SEDAR under the Corporation's profile at www.sedar.com.

Additional financial information is provided in the Corporation's financial statements and management's discussion and analysis for the year ended December 31, 2019 filed under the Corporation's profile at www.sedar.com.

APPENDIX A

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

To the Board of Directors of Kelt Exploration Ltd. (the "Company"):

1. We have evaluated the major properties and audited the minor properties of 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 or audit.

3. We carried out our evaluation of the major properties and audit of the minor properties 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 or audit to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation or audit 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 or audited 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 management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule **Total**	December 31, 2019	Canada	11,242	3,977,240	Nil	3,988,482

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

7. We have no responsibility to update the report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report entitled "Evaluation of the P&NG Reserves of Kelt Exploration Ltd. (As of December 31, 2019)."

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
February 13, 2020

(signed) *"Angela Hoza"*
Angela Hoza, P.Eng.
Senior Petroleum Engineer

(signed) *"Brent Hawkwood"*
Brent Hawkwood, C.E.T.
Senior Technologist

(signed) *"Victor Verkhogliad"*
Victor Verkhogliad, P. Geol.
Manager, Geoscience

(signed) *"Cameron P. Six"*
Cameron P. Six, P. Eng.
CEO

(signed) *"Alec Kovaltchouk"*
Alec Kovaltchouk, P. Geo.
VP, Geoscience

APPENDIX B

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

Report of Management and Directors
on Reserves Data and Other Information

Management of Kelt Exploration Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.

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

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

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

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

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

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

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

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

(c) the content and filing of this report.

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

(signed) *"David J. Wilson"*
David J. Wilson
President and Chief Executive Officer

(signed) *"Bruce Gigg"*
Bruce Gigg
Vice President, Engineering

(signed) *"Michael R. Shea"*
Michael R. Shea
Director

(signed) *"Neil G. Sinclair"*
Neil G. Sinclair
Director

Dated this 19th day of February, 2020.

APPENDIX C

DEFINITIONS USED FOR RESERVE CATEGORIES

The following definitions form the basis of the classification of reserves and values presented in the Sproule Report. The definitions are those set out in NI 51-101 and/or 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) and incorporated into NI 51-101 by reference.

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology;
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
- a remaining reserve life of 50 years.

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

1. Proved Reserves

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

2. Probable Reserves

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

3. Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in the Sproule Report.

Other criteria that must also be met for categorization of reserves are provided in Section 5.5 of the COGE Handbook.

Each of the reserves categories (proved, probable, and possible) may be divided into developed or undeveloped categories.

4. Developed Reserves

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

5. Developed Producing Reserves

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

6. Developed Non-Producing Reserves

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

7. Undeveloped Reserves

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

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

8. Levels of Certainty for Reported Reserves

The qualitative certainty levels contained in the definitions in Sections 1, 2 and 3 are applicable to individual reserves entities, which refers to the lowest level at which reserves estimates are made, and to reported reserves, which refers to the highest level sum of individual entity estimates for which reserve estimates are made.

Reported total reserves estimated by deterministic or probabilistic methods, whether comprised of a single reserves entity or an aggregate estimate for multiple entities, should target the following levels of certainty under a specific set of economic conditions:

(a) There is a 90% probability that at least the estimated proved reserves will be recovered.

(b) There is a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered.

(c) There is a 10% probability that at least the sum of the estimated proved reserves plus probable reserves plus possible reserves will be recovered.

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a 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 Section 5.5.3 of the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

9. **Remaining Recoverable Reserves** are the total remaining recoverable reserves associated with the acreage in which the Corporation has an interest.

10. **Company Gross Reserves** are the Corporation's working interest share of the remaining reserves, before deduction of any royalties.

11. **Company Net Reserves** are the gross remaining reserves of the properties in which the Corporation has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.

12. **Net Production Revenue** is income derived from the sale of net reserves of oil, pipeline gas, and gas by-products, less all capital and operating costs.

13. **Fair Market Value** is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

14. **Barrels of Oil Equivalent (BOE) Reserves** - BOE is the sum of the oil reserves, plus the gas reserves divided by a factor of 6, plus the natural gas liquid reserves, all expressed in barrels or thousands of barrels. Equivalent reserves can also be expressed in thousands of cubic feet of gas equivalent (McfGE) using a conversion ratio of 1 bbl:6 Mcf.

15. **Oil (or Crude Oil)** – a mixture consisting mainly of pentanes and heavier hydrocarbons that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas. Crude oil volumes are further divided into Product Types, for reporting purposes.

16. **Gas (or Natural Gas)** – a mixture of lighter hydrocarbons that exist either in the gaseous phase or in solution in crude oil in reservoirs, but are gaseous at atmospheric conditions. Natural gas may contain sulphur or other non-hydrocarbon compounds. Natural gas volumes are further divided into Product Types, for reporting purposes.

17. **Non-Associated Gas** – an accumulation of natural gas in a reservoir where there is no crude oil.

18. **Associated Gas** - the gas cap overlying a crude oil accumulation in a reservoir.

19. **Solution Gas** - gas dissolved in crude oil.

20. **Natural Gas By Products** – those components that can be removed from natural gas including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

21. **Products Types** – sub-classify the principle product types of petroleum, crude oil, gas and by-products, into specific groupings based on the properties of the hydrocarbon and the properties of the accumulation and reservoir rock from which it is found. Regulatory agencies may define in legislation the production types they require to be used for reporting purposes in their jurisdiction. The Canadian Securities Association (CSA) defines the following Product Types for reporting purposes in National Instrument 51-101, effective July 1, 2015.

Crude Oil

(a) **Light Crude Oil** means crude oil with a relative density greater than 31.1 degrees API gravity;

(b) **Medium Crude Oil** means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity;

(c) **Heavy Crude Oil** means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity;

(d) **Tight Oil** means crude oil:

(i) contained in dense organic rich rocks, including low-permeability shales, siltstones and carbonates, in which the crude oil is primarily contained in microscopic pore spaces that are poorly connected to one another, and

(ii) that typically requires the use of hydraulic fracturing to achieve economic production rates;

(e) **Bitumen** means a naturally occurring solid or semi-solid hydrocarbon:

(i) consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds (mPa.s) or 10,000 centipoise (cP) measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and

(ii) that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods;

(f) **Synthetic Crude Oil** means a mixture of liquid hydrocarbons derived by upgrading bitumen, kerogen or other substances such as coal, or derived from gas to liquid conversion and may contain sulphur or other compounds;

Natural Gas

(g) **Conventional Natural Gas** means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features;

(h) **CoalBed Methane** means natural gas that:

(i) primarily consists of methane, and

(ii) is contained in a coal deposit;

(i) **Shale Gas** means natural gas:

(i) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily absorbed on the kerogen or clay minerals, and

(ii) that usually requires the use of hydraulic fracturing to achieve economic production rates;

(j) **Synthetic Gas** means a gaseous fluid:

(i) generated as a result of the application of an in-situ transformation process to coal or other hydrocarbon-bearing rock, and

(ii) comprised of not less than 10% by volume of methane;

(k) **Gas Hydrate** means a naturally occurring crystalline substance composed of water and gas in an ice-lattice structure;

By-Products

(l) **Natural Gas Liquids** means those hydrocarbon components that can be recovered from natural gas as a liquid including, but not, limited to, ethane, propane, butanes, pentanes plus and condensates; and

(m) **Sulphur** is a non-hydrocarbon elemental by-product of gas processing and refining.

APPENDIX D
FORM 52-110F1 – *AUDIT COMMITTEE INFORMATION REQUIRED IN AN AIF*

1. The Audit Committee Charter

The charter of the Audit Committee is attached as Schedule 1 to this Appendix D.

2. Composition of the Audit Committee

The Audit Committee of the Corporation is composed of the following individuals:

Member	Independent	Financially literate
Robert Dales	Independent(1)	Financially literate(2)
Geraldine L. Greenall	Independent(1)	Financially literate(2)
Neil Sinclair	Independent(1)	Financially literate(2)

Notes:
(1) A member of an audit committee is independent if the member has no direct or indirect material relationship with the Corporation which could, in the view of the Board of Directors, reasonably interfere with the exercise of a member's independent judgment.
(2) An individual is financially literate if he has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and level of complexity of accounting issues that can reasonably be expected to be raised by the Corporation's financial statements.

3. Relevant Education and Experience

Mr. Dales holds an MBA. He also has over 25 years of public issuer experience, both as an officer and as a director.

Ms. Greenall holds a Bachelor of Commerce (Finance), a CFA and an ICD.D, having completed the Institute of Corporate Directors – Directors Education Program and has over 2 years of public issuer experience as a director.

Mr. Sinclair, the Chair of the Audit Committee, holds a BA and an MBA. He has also been President of an active private corporation, with significant real estate operations, for over 47 years. He also has over 18 years of public company experience as an officer and as a director.

4. Reliance on Certain Exemptions

At no time since incorporation has the Corporation relied on any exemption from NI 52-110, other than in Section 2.4 of NI 52-110 (*De Minimis Non-audit Services*).

5. Reliance on the Exemption in Subsection 3.3(2) or Section 3.6

At no time since incorporation has the Corporation relied on the exemptions in Sections 3.3(2) or 3.6 of NI 52-110.

6. Reliance on Section 3.8

At no time since incorporation has the Corporation relied on Section 3.8 of NI 52-110.

7. Audit Committee Oversight

At no time since incorporation was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board of Directors.

8. Pre-Approval Policies and Procedures

The Audit Committee of the Corporation has adopted specific policies and procedures for the engagement of non-audit services entitled *"Procedures for Approval of Audit and Non-Audit Services by the External Auditors"* (the "**Procedure**"). Under the Procedure, the auditors may not act in any capacity where they function as management, audit their own work or serve in an advocacy role on behalf of the Corporation. Various audit related services provided by the auditors have been pre-approved. Management is required, however, to obtain pre-approval of the Audit Committee for services where engagement fees are expected to exceed $20,000. Where fees for a particular engagement are expected to be less than or equal to $20,000 the Chair of the Audit Committee is to be notified expeditiously of the commencement of such services. If an engagement with the auditors for a particular service is contemplated that is neither expressly forbidden under the Procedure nor covered under the range of services provided for therein, such an engagement must be pre-approved. The Audit Committee has delegated the authority to effect such pre-approval to the Chair of the Audit Committee. Pre-approved non-audit services shall be provided pursuant to an engagement letter signed by the auditors which shall set out the particular non-audit services to be provided. At every regularly scheduled meeting of the Audit Committee, management is required to report on all new pre-approved engagements of the auditors since the last such report.

9. External Auditor Service Fees (By Category)

The aggregate fees billed by the Corporation's external auditors in each of the last two fiscal years are set forth in the table below:

Year Ended	Audit Fees (1)	Audit-Related Fees(2)	Tax Fees(3)	All Other Fees(4)
December 31, 2019	$201,000	$52,200	$42,100	$18,400
December 31, 2018	$196,000	$80,800	$54,200	$225,800

Notes:

(1) The aggregate audit fees paid or payable.

(2) Audit related services include quarterly reviews, procedures related to new accounting standards and complex transaction accounting.

(3) The aggregate fees billed for professional services rendered for tax advice and tax planning

(4) The aggregate non-re-occurring fees billed for professional services primarily rendered for commodity tax recovery engagement.

SCHEDULE 1
AUDIT COMMITTEE CHARTER OF KELT EXPLORATION LTD.

This charter governs the operations of the audit committee (the "**Committee**") of Kelt Exploration Ltd. (the "**Corporation**"). The Committee shall report to the Board of Directors (the "**Board**") of the Corporation. The following is the text of the Committee's charter.

I. PURPOSE

(a) The primary function of the Committee is to assist the Board in fulfilling its responsibilities regarding the integrity of the Corporation's financial statements including the financial reporting process and systems of internal controls, the compliance by the Corporation with legal and regulatory requirements and the qualifications, performance and independence of the Corporation's external auditor by reviewing:

(i) the financial information that will be provided to the shareholders, regulatory authorities and others;

(ii) the systems of internal controls management has established;

(iii) all audit processes;

(iv) all reporting from the external auditors.

(b) Primary responsibility for the financial reporting, information systems, risk management and internal controls of the Corporation is vested in management and is overseen by the Board. While the Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits or to determine that the Corporation's financial statements are complete and accurate and are in accordance with generally accepted accounting principles. These are the responsibilities of management and the external auditor. Nor is it the duty of the Committee to conduct investigations, to resolve disagreements, if any, between management and the external auditor or to assure compliance with laws and regulations.

II. COMPOSITION AND OPERATIONS

(a) The Committee shall be composed of not fewer than three directors, none of whom shall be officers, employees or consultants to the Corporation or any of its related legal entities. The Committee shall only be comprised of unrelated directors. An unrelated director is a director who is independent of management and is free from any interest or other relationship which could reasonably be perceived to materially interfere with the director's ability to act with a view to the best interests of the Corporation as the case may be, other than interests and relationships arising from shareholding.

(b) The Committee shall review and reassess this Charter annually.

(c) All Committee members shall be financially literate (as defined by the Toronto Stock Exchange or other regulatory authority), or shall become financially literate within a reasonable period of time after appointment to the Committee, and at least one member shall have appropriate financial management experience or expertise.

(d) The Corporation's auditors shall be advised of the names of the Committee members and when appropriate will receive notice of and be invited to attend meetings of the Committee and to be heard at those meetings on matters relating to the auditor's duties.

(e) The Committee shall meet with the external auditors as it deems appropriate to consider any matter that the Committee or auditors determine should be brought to the attention of the Board or shareholders.

(f) The Committee shall meet at least four times each year.

(g) The Committee shall have access to the Corporation's senior management and documents as required to fulfill its responsibilities and is provided with the resources necessary to carry out its responsibilities.

(h) The Committee shall provide open avenues of communication among management, employees, external auditors and the Board.

(i) The secretary to the Committee shall be the Corporate Secretary or an appointee of the Corporate Secretary.

(j) Notice of the time and place of every meeting shall be given to each Committee member at least 48 hours prior to the meeting.

(k) A majority of the voting membership of the Committee present in person or by telephone or other electronic telecommunication device shall constitute a quorum.

(l) The President, Chief Executive Officer, Vice President, Finance, and Chief Financial Officer and external auditor would be expected to be available to attend meetings or portions thereof. The external auditors would meet at least twice annually with the Committee. Others may or may not attend the meetings at the sole discretion of the Committee.

(m) Minutes of Committee meetings shall be approved by the Committee and sent to all directors of the Board.

III. DUTIES AND RESPONSIBILITIES

(a) Financial Statements and Other Financial Information

The Committee will review and recommend for approval to the Board financial information that will be made publicly available. This includes:

(i) the Corporation's annual and quarterly financial statements;

(ii) the Corporation's press releases and reports as they relate to the finances of the Corporation;

(iii) the Management Discussion and Analysis;

(iv) the financial content of the Annual Report;

(v) the Annual Information Form and any Prospectus or Private Placement Memorandums; and

(vi) any reports required by regulatory or government authorities as they relate to the finances of the Corporation.

The Committee will review and discuss:

(vii) the appropriateness of accounting policies and financial reporting practices to be adopted by the Corporation;

(viii) any significant proposed changes in financial reporting and accounting policies and practices to be adopted by the Corporation;

(ix) any new or pending developments in accounting and reporting standards that may affect the Corporation;

(x) ascertain compliance with the covenants under applicable loan agreements;

(xi) management’s key estimates and judgments that may be material to financial reporting; and

(xii) any other matters required to be reviewed under applicable legal, regulatory or stock exchange requirements.

(b) Risk Management, Internal Control and Information Systems

The Committee will review and obtain reasonable assurance that the risk management, internal control and information systems are operating effectively to produce accurate, appropriate and timely management and financial information. This includes:

(i) review the Corporation’s risk management controls and policies;

(ii) obtain reasonable assurance that the information systems are reliable and the systems of internal controls are properly designed and effectively implemented through discussions with and reports from management and the external auditor;

(iii) review management steps to implement and maintain appropriate internal control procedures including a review of policies;

(iv) review adequacy of security of information, information systems and recovery plans;

(v) monitor compliance with statutory and regulatory obligations;

(vi) review the appointment of the Vice President, Finance and Chief Financial Officer; and

(vii) review the adequacy of accounting and finance resources.

(c) External Audit

The Committee will review the planning and results of external audit activities and the ongoing relationship with the external auditor. This includes:

(i) review and recommend to the Board, for shareholder approval, engagement of the external auditor including, as part of such review and recommendation, an evaluation of the external auditors qualifications, independence and performance;

(ii) review and recommend to the Board the annual external audit plan, including but not limited to the following:

1. engagement letter;

2. objectives and scope of the external audit work;

3. procedures for quarterly review of financial statements;

4. materiality limit;

5. areas of audit risk;

6. staffing;

7. timetable; and

8. proposed fees.

(iii) meet with the external auditor to discuss the Corporation's quarterly and annual financial statements and the auditor's report including the appropriateness of accounting policies and underlying estimates;

(iv) review and advise the Board with respect to the planning, conduct and reporting of the annual audit, including but not limited to:

1. any difficulties encountered, or restrictions imposed by management during the annual audit;

2. any significant accounting or financial reporting issue including the resolution of any disagreement between management and the external auditors;

3. the auditor's evaluation of the Corporation's system of internal controls, procedures and documentation;

4. the post audit or management letter containing any findings or recommendation of the external auditor, including management's response thereto and the subsequent follow-up to any identified internal control weakness; and

5. assess the performance and consider the annual appointment of external auditors for recommendation to the Board;

(v) review and receive assurances on the independence of the external auditor;

(vi) review the non-audit services to be provided by the external auditor's firm and consider the impact on the independence of the external audit; and

(vii) meet periodically with the external auditor without management present.

(d) Other

(i) review material litigation and its impact on financial reporting; and

(ii) establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters.

IV. ACCOUNTABILITY

The committee shall report its discussions to the Board by distributing the minutes of its meetings and where appropriate, by oral report at the next Board meeting.

V. STANDARDS OF LIABILITY

Nothing contained in this Charter is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in these terms of reference are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.