KELT EXPLORATION LTD.

ANNUAL INFORMATION FORM

For the Year Ended
December 31, 2022

March 3, 2023

TABLE OF CONTENTS

SELECTED DEFINITIONS 1
PRESENTATION OF INFORMATION 2
ABBREVIATIONS AND CONVERSIONS 2
FORWARD-LOOKING STATEMENTS AND INFORMATION 3
CORPORATE STRUCTURE 5
GENERAL DEVELOPMENT OF THE BUSINESS 6
DESCRIPTION OF THE BUSINESS 7
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION 9
PRICING ASSUMPTIONS 12
RECONCILIATION OF CHANGES IN RESERVES AND FUTURE NET REVENUE 13
ADDITIONAL INFORMATION RELATING TO RESERVES DATA 14
RISK FACTORS 21
INDUSTRY CONDITIONS 39
DIVIDEND POLICY 55
DESCRIPTION OF SHARE CAPITAL 55
MARKET FOR SECURITIES 56
PRIOR SALES 56
ESCROWED SECURITIES 57
DIRECTORS AND OFFICERS 57
AUDIT COMMITTEE 59
LEGAL PROCEEDINGS AND REGULATORY ACTIONS 59
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 59
TRANSFER AGENT AND REGISTRAR 59
MATERIAL CONTRACTS 59
INTERESTS OF EXPERTS 59
ADDITIONAL INFORMATION 60

APPENDICES

Appendix A – Form 51-101F2 – *Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor*
Appendix B – Form 51-101F3 – *Report of Management and Directors on Oil and Gas Disclosure*
Appendix C – Definitions Used for Reserves Categories
Appendix D – Form 52-110F1 – *Audit Committee Information Required in an AIF*

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.

"**Annual Information Form**" means this annual information form of the Corporation dated March 3, 2023.

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

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

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

"**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.

"**COVID-19**" means the novel coronavirus which was declared a global pandemic by the World Health Organization on March 11, 2020.

"**Credit Facility**" has the meaning set forth under the heading "*General Development of the Business – 2021*".

"**Debentures**" has the meaning set forth under the heading "*General Development of the Business – History of Kelt – 2020*".

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

"**Inga Assets**" has the meaning set forth under the heading "*General Development of the Business – 2020*".

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

"**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.

"**Preferred Shares**" means the preferred shares of Kelt.

"**RSUs**" means the restricted share units of Kelt.

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

"**Sproule Report**" means the report prepared by Sproule dated February 6, 2023 and effective as of December 31, 2022 entitled "*Evaluation of the P&NG Reserves of Kelt Exploration Ltd. (As of December 31, 2022)*".

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

PRESENTATION OF INFORMATION

The information contained in this Annual Information Form is presented as at December 31, 2022 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 and Other Financial 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. The Corporation also presents operating netbacks on a per boe basis which allows management to better analyze performance against prior periods, on a comparable basis, and is a key industry performance measure of operational efficiency.

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.

See the "Adjusted Funds from Operations" section of Kelt's Management's Discussion and Analysis as at and for the year ended December 31, 2022 which provides a reconciliation of the operating netback from P&NG sales, which is a generally accepted accounting principles measure.

"Capital expenditures, before A&D" "capital expenditures net of A&D" and "capital expenditures, after property acquisitions" are measures the Corporation uses to monitor its investment in exploration and evaluation, investment in property plant and equipment, and investment in acquisition activities. The most directly comparable generally accepted accounting principles measure is Cash provided by (used in) financing activities, and is calculated as follows:

	Three months ended December 31		Year ended December 31	
(CA$ thousands, except as otherwise indicated)	**2022**	2021	**2022**	2021
Cash provided by investing activities	**95,916**	74,421	**328,945**	191,540
Change in non-cash investing working capital	**(27,322)**	(7,303)	**(11,405)**	21,971
Capital expenditures, net of A&D	**68,594**	67,118	**317,540**	213,511
Property acquisitions[(1)]	**(12)**	(36)	**(933)**	(252)
Property dispositions[(1)]	**-**	(57)	**41**	9,048
Capital expenditures, before A&D	**68,582**	67,025	**316,648**	222,307

Note:
(1) Property acquisitions and dispositions for the year ended December 31, 2022 includes $2.5 million of non-cash consideration. Property dispositions for the year ended December 31, 2021 includes $200k of non-cash consideration.

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
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 currency exchange and interest 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;
- third party production companies' inability to manage inflationary cost pressures; 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 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;
- ongoing impacts of COVID-19, including but not limited to impacts on field activity levels, demand for and supply of hydrocarbons, commodity prices and health and safety considerations and restrictions which may impact the ability of the Corporation to carry on business as planned;
- 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 Corporation 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 west central Alberta and northeastern British Columbia. Kelt's land holdings are located in three operating divisions, namely: (a) Pouce Coupe/Progress, Alberta - Kelt's Alberta development division; (b) Wembley/Pipestone, Alberta – Kelt's Alberta exploration division; and (c) Oak/Flatrock, British Columbia – Kelt's British Columbia exploration division. Kelt also has a number of minor properties not included in the three operating divisions. See "*Description of the Business*" and "*Statement of Reserves Data and Other Oil and Gas Information*".

History of Kelt

General History

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., ExxonMobil Celtic ULC and the shareholders and debentureholders of Celtic (the "**Arrangement**"). The Arrangement was completed on February 26, 2013 pursuant to which, among other things, each shareholder received one-half (1/2) of one Common Share of Kelt for each common share of Celtic held. In connection with the Arrangement, Celtic assigned and transferred to Kelt all of Celtic's right, title, estate and interest in and to certain petroleum, natural gas and related hydrocarbon rights and related personal property interests. Since the completion of the Arrangement, 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".

2020

On February 20, 2020, Kelt announced that it had 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.

On March 17, 2020, Kelt announced that the board had approved a reduction in capital expenditures for 2020, reducing its capital expenditure budget to $145.0 million.

On August 21, 2020, Kelt completed the sale of its oil and gas assets in its Inga/Fireweed/Stoddart Division (the "**Inga Assets**"), located in British Columbia effective as of July 1, 2020. Cash proceeds were $510.0 million, prior to closing adjustments. In addition, the purchaser assumed $28.8 million of financing liabilities and $1.1 million of lease and other liabilities.

Concurrently with the completion of the sale of its Inga Assets, Kelt paid out all amounts outstanding under the $350.0 million revolving committed term credit facility under the second amended and restated syndicated credit agreement, as amended, entered into by Kelt on March 29, 2019. For business continuity purposes, Kelt entered into a new $20.0 million demand revolving credit facility with a Canadian chartered bank.

In addition, on August 21, 2020, Kelt announced the Board of Directors had approved $20.0 million in capital expenditures for the second half of 2020, excluding capital expenditures that are part of the closing adjustments with respect to the sale of the Inga Assets.

On August 21, 2020, Kelt also mailed a redemption notice to the registered holders of its 5.00% convertible unsecured subordinated debentures due May 31, 2021 (the "**Debentures**") and to Computershare Trust Company of Canada, as debenture trustee. Pursuant to the redemption notice, Kelt redeemed the $89,910,000 of outstanding principal amount of the Debentures plus all accrued but unpaid interest up to but excluding the date of redemption of October 3, 2020. In connection with the redemption of the Debentures, the Debentures were delisted from the Toronto Stock Exchange.

On November 10, 2020, Kelt announced that the Board of Directors had approved a capital expenditure budget of $90.0 million for 2021 and that Louise K. Lee had been appointed Corporate Secretary and Douglas J. Errico had been

appointed as Senior Vice President, Land and Corporate Development as of November 9, 2020. Mr. Errico has been Vice President, Land of Kelt since October 22, 2012.

2021

On January 7, 2021, Kelt announced the release of its inaugural ESG Report, dated January 7, 2021, as part of its ongoing commitment to health and safety, responsible and sustainable resource development, good governance practices and community engagement. The ESG Report can be viewed on Kelt's website at www.keltexploration.com.

On May 24, 2021, Kelt announced that the Board of Directors had approved an increase to its capital expenditure program for 2021 from $120.0 million to $150.0 million

On June 30, 2021, Kelt announced the appointment of Janet E. Vellutini as a director of the Corporation effective July 1, 2021 and the retirement of Robert J. Dales as a director of the Corporation effective July 1, 2021.

On November 10, 2021, Kelt announced that the Board of Directors had approved an increase to its capital expenditure program for 2021 from $175.0 million to between $190.0 and $200.0 million and that the Corporation had entered into a new credit facility with a borrowing capacity of $100.0 million (the "**Credit Facility**"). Kelt also announced the Board of Directors had approved an initial capital expenditure budget between the range of $200.0 million and $210.0 million for 2022.

2022

Kelt released its second ESG Report dated February 17, 2022 as part of its ongoing commitment to disclose to stakeholders its policies and achievements in health and safety, sustainable resource development, governance practices and community engagement.

On March 10, 2022, Kelt announced that the Board of Directors had approved an increase to its capital expenditure program for 2022 from a range of $200.0 - $210.0 million to $250.0 million.

On May 5, 2022, Kelt announced that the Board of Directors had approved an increase to its capital expenditure program for 2022 from $250.0 million to $265.0 million.

On July 6, 2022, Kelt announced that the Board of Directors had approved an increase to its capital expenditure program for 2022 from $265.0 million to $300.0 million.

On November 10, 2022, Kelt announced that the Board of Directors had approved an initial capital expenditure program for 2023 of $310.0 million.

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, 2022.

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 west central Alberta and northeastern British Columbia. Kelt's land holdings are located in three operating divisions, namely: (a) Pouce Coupe/Progress in Alberta; (b) Wembley/Pipestone in Alberta and (c) Oak/Flatrock in British Columbia. Kelt also has a number minor properties not included in the three operating divisions.

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 may complement its exploration and development drilling program with acquisitions and dispositions that optimize its asset base.

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 to third party 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 natural gas transactions vary in duration, generally for one year or less. The Corporation has a combination of firm and interruptible pipeline transportation service to deliver its crude oil, natural gas, and NGLs production to markets that range in length from 1-13 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 averaged $94.80 US$/bbl WTI and AECO 5A gas reference prices averaged $5.31 Cdn$/MMBtu during 2022.

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 2022, Kelt's natural gas sales were split between the following markets: AECO/Station 2 (71%), Dawn (20%), Chicago (5%), and other (4%).

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 4 part-time employees located at its head office. In addition, the Corporation has 25 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.

Periodically, Kelt updates its ESG performance as part of its ongoing commitment to disclose to stakeholders its policies and achievements in health and safety, sustainable resource development, governance practices and community engagement.

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 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, 2021 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, 2022 based on forecast price and cost assumptions.

SUMMARY OF OIL AND GAS RESERVES as of December 31, 2022 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	10,052	7,735	77,750	69,663	169,612	150,204	9,783	7,485	61,062	51,864
Developed Non-Producing	408	343	1,925	1,738	5,413	4,971	492	405	2,123	1,867
Undeveloped	20,385	16,479	75,190	67,846	389,021	346,914	31,135	25,044	128,889	110,649
TOTAL PROVED	**30,845**	**24,557**	**154,865**	**139,247**	**564,046**	**502,089**	**41,410**	**32,934**	**192,074**	**164,380**
PROBABLE	22,018	16,944	97,992	87,069	451,028	394,509	35,206	27,124	148,727	124,332
TOTAL PROVED PLUS PROBABLE	**52,863**	**41,501**	**252,857**	**226,316**	**1,015,074**	**896,598**	**76,616**	**60,058**	**340,801**	**288,712**

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, 2022.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE as of December 31, 2022[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	1,018,414	944,573	841,642	757,588	691,727	926,374	875,736	787,974	714,370	656,022	16.23
Developed Non-Producing	43,983	35,667	29,882	25,677	22,492	33,694	27,284	22,806	19,550	17,087	16.01
Undeveloped	2,239,463	1,493,395	1,055,557	779,016	593,157	1,713,130	1,120,064	771,441	552,180	405,875	9.54
TOTAL PROVED	**3,301,860**	**2,473,634**	**1,927,081**	**1,562,281**	**1,307,376**	**2,673,199**	**2,023,084**	**1,582,221**	**1,286,100**	**1,078,985**	**11.72**
PROBABLE	3,119,740	2,079,692	1,503,033	1,148,264	911,883	2,381,516	1,574,098	1,124,961	849,406	666,734	12.09
TOTAL PROVED PLUS PROBABLE	**6,421,600**	**4,553,326**	**3,430,114**	**2,710,545**	**2,219,259**	**5,054,715**	**3,597,182**	**2,707,182**	**2,135,506**	**1,745,719**	**11.88**

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 $238.0 million (undiscounted) for total proved reserves and $276.7 million (undiscounted) for total proved plus probable reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2022 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	9,020,770	1,428,407	2,842,408	1,210,125	237,969	3,301,860	628,662	2,673,199
Proved Plus Probable Reserves	16,199,785	2,717,033	4,740,290	2,044,154	276,709	6,421,600	1,366,885	5,054,715

FUTURE NET REVENUE BY PRODUCTION TYPE as of December 31, 2022 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)	665,620	15.31
	Conventional Natural Gas (including associated by-products) (1)	1,261,462	10.43
	Total	**1,927,081**	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	1,093,029	15.44
	Conventional Natural Gas (including associated by-products) (1)	2,337,085	10.73
	Total	**3,430,114**	

Note:
(1) Includes corporate capital gas cost allowance.

PRICING ASSUMPTIONS

Forecast Prices and Costs - December 31, 2022

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, 2022.

FORECAST PRICES USED IN PREPARING RESERVES DATA Sproule Associates Limited Price Forecast Effective December 31, 2022							
	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							
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
2020	39.40	45.39	35.59	35.92	16.31	21.87	49.85
2021	67.91	80.31	68.73	69.04	43.39	51.64	85.88
2022	94.23	119.73	101.64	101.96	50.11	61.68	121.28

FORECAST PRICES USED IN PREPARING RESERVES DATA
Sproule Associates Limited
Price Forecast
Effective December 31, 2022

	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)
Forecast							
2023	86.00	110.67	88.00	89.32	38.13	54.47	114.67
2024	84.00	101.25	89.38	90.72	37.28	52.50	105.00
2025	80.00	96.18	84.06	85.32	37.68	50.00	100.00
2026	81.60	98.10	85.74	87.03	38.44	51.00	102.00
2027	83.23	100.06	87.46	88.77	39.21	52.02	104.04
2028	84.90	102.06	89.21	90.55	39.99	53.06	106.12
2029	86.59	104.10	90.99	92.36	40.79	54.12	108.24
2030	88.33	106.18	92.81	94.20	41.61	55.20	110.41
2031	90.09	108.31	94.67	96.09	42.44	56.31	112.62
2032	91.89	110.47	96.56	98.01	43.29	57.43	114.87
Thereafter	Escalation rate of 2.0% thereafter						

FORECAST PRICES USED IN PREPARING RESERVES DATA
Sproule Associates Limited
Price Forecast
Effective December 31, 2022

	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					
2018	3.07	1.53	3.92	2.4	0.77
2019	2.53	1.80	3.20	(0.7)	0.75
2020	2.13	2.24	2.50	(5.2)	0.75
2021	3.72	3.64	5.74	4.1	0.80
2022	6.51	5.43	8.02	8.6	0.77
Forecast					
2023	5.00	4.33	6.52	0.0	0.75
2024	4.50	4.34	5.47	3.0	0.80
2025	4.25	4.00	5.15	2.0	0.80
2026	4.34	4.08	5.26	2.0	0.80
2027	4.42	4.16	5.36	2.0	0.80
2028	4.51	4.24	5.47	2.0	0.80
2029	4.60	4.33	5.58	2.0	0.80
2030	4.69	4.42	5.69	2.0	0.80
2031	4.79	4.50	5.81	2.0	0.80
2032	4.88	4.59	5.92	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, 2022 were $117.18/Bbl for oil, $67.64/Bbl for NGLs and $6.63/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, 2022 based on forecast price and cost assumptions.

FACTORS	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL[1]			CONVENTIONAL GAS[1]			NATURAL GAS LIQUIDS[1]			TOTAL EQUIVALENT		
	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, 2021	**14,182**	**10,065**	**24,247**	**492,058**	**403,890**	**895,948**	**37,899**	**42,678**	**80,577**	**134,092**	**120,057**	**254,149**
Discoveries	252	59	310	2,578	657	3,235	273	70	342	954	238	1,192
Extensions	2,448	1,420	3,868	48,697	99,765	148,462	904	2,750	3,655	11,468	20,797	32,266
Infill Drilling	5,377	2,067	7,445	120,710	27,434	148,144	8,954	3,068	12,022	34,448	9,709	44,158
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	97	24	121	442	60	502	7	1	8	178	35	213
Dispositions	(94)	(314)	(408)	(601)	(2,185)	(2,786)	(81)	(293)	(374)	(275)	(971)	(1,246)
Economic Factors	692	761	1,454	21,222	16,696	37,918	865	935	1,800	5,094	4,480	9,573
Technical Revisions[2]	9,950	7,936	17,885	72,165	2,703	74,868	(5,934)	(14,003)	(19,936)	16,044	(5,617)	10,426
Production	(2,059)	-	(2,059)	(38,360)	-	(38,360)	(1,478)	-	(1,478)	(9,930)	-	(9,930)
December 31, 2022	30,845	22,018	52,863	718,911	549,020	1,267,931	41,410	35,206	76,616	192,073	148,728	340,801

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.

(3) Proved component of Category Change PBUD to proved volumes have been included in the Extension or Infill 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 for both proved and proved and probable 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, 2022.

Proved Undeveloped Reserves

Year/Period	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS[2]		NATURAL GAS LIQUIDS		TOTAL EQUIVALENT	
	First Attributed (Mbbl)	Cumulative at Year End[1] (Mbbl)	First Attributed (MMcf)	Cumulative at Year End[1] (MMcf)	First Attributed (Mbbl)	Cumulative at Year End[1] (Mbbl)	First Attributed (MBOE)	Cumulative at Year End[1] (MBOE)
December 31, 2020	1,356.6	9,936.5	11,629	225,424	2,334.4	16,630.2	5,629.3	64,137.3
December 31, 2021	275.8	9,069.3	59,776	302,720	8,194.9	28,631.1	18,433.4	88,153.8
December 31, 2022	5,592.7	20,384.9	151,129	464,211	9,349.2	31,134.9	40,130.1	128,888.3

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.

Probable Undeveloped Reserves

Year/Period	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS[2]		NATURAL GAS LIQUIDS		TOTAL EQUIVALENT	
	First Attributed (Mbbl)	Cumulative at Year End[1] (Mbbl)	First Attributed (MMcf)	Cumulative at Year End[1] (MMcf)	First Attributed (Mbbl)	Cumulative at Year End[1] (Mbbl)	First Attributed (MBOE)	Cumulative at Year End[1] (MBOE)
December 31, 2020	1,913.0	11,074.1	28,446	233,602	5,426.2	23,175.4	12,080.1	73,183.3
December 31, 2021	820.3	8,461.4	110,405	345,795	15,598	39,872.4	34,819.1	105,966.4
December 31, 2022	4,667.2	19,408.7	154,292	474,505	6,761.9	32,352.5	37,144.4	130,845.5

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.

Sproule has assigned 128,888.3 MBOE of proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with approximately $1,204.2 million of associated undiscounted future capital expenditures. Proven undeveloped capital spending in the first two forecast years of the Sproule Report accounts for approximately $491.6 million or 41%, 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 130,845.5 MBOE of probable undeveloped reserves and has allocated additional future development capital of approximately $833.0 million to all probable undeveloped reserves with 26% scheduled for the first two years. The remaining probable undeveloped reserves are expected to be developed within 5 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 five years for proved undeveloped reserves and six 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$)**	**Proved Plus Probable Reserves (M$)**
2023	227,633.9	323,577.9
2024	269,862.5	393,550.5
2025	264,249.0	418,020.5
2026	201,766.5	442,607.0
2027	246,612.6	466,397.6
Remaining Years	-	-
Total Undiscounted	1,210,124.6	2,044,153.5

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 2023, the Corporation has established a $285 million capital program to fund its exploration and development activities which is in line with the 2023 proved and proved plus probable future development costs. The 2023 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 2023.

Kelt expects to fund the development costs of these reserves through a combination of the funds available from its Credit Facility, 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, 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 of December 31, 2022, the Corporation has interests in 168,908 gross (106,767 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, and 20 MMcf/d of third party gas processing capacity. 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 of December 31, 2022, the Corporation has interests in 165,928 gross (143,654 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 34 MMcf/d of deep cut gas processing capacity and 3 MMcf/d of gas processing capacity at Pipestone. At Wembley/Pipestone, the Corporation is primarily targeting light oil and condensate rich natural gas in the Montney formation.

Oak/Flatrock

As of December 31, 2022, the Corporation has interests in 194,403 gross (193,131 net) acres of land in this area which is located approximately 30 kilometres north east of Fort St. John, British Columbia. At Oak/Flatrock, the Corporation has a gas compression and oil battery facility at Oak 6-35 with a capacity of 5,000 bbld/ of oil and 28 MMcf/d of natural gas.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2022 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	237	160.1	226	128.9	171	101.2	365	184.9	61	24.3
British Columbia	1	1.0	23	21.3	-	-	43	24.2	1	1.0
TOTAL	238	161.1	249	150.2	171	101.2	408	209.1	62	25.3

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, 2022 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 2023**
Alberta	258,861	186,460	8,068
British Columbia	203,203	189,315	-
TOTAL	462,064	375,775	8,068

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 and see Kelt's annual financial statements as at, and for the year ended December 31, 2022 (note 11)**.**

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 1,128 gross (647.0 net) wells, comprising currently producing, non-producing and service wells. As at December 31, 2022, the Corporation has estimated its share of the total abandonment and reclamation costs for its existing wells and facilities to be $126.4 million undiscounted (approximately $31.7 million discounted at 10%), of which Kelt expects to pay approximately $9 million over the next three financial years.

The Sproule Report 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 2022, Kelt had approximately $768.4 million of tax pools and losses available. It is expected, based upon current legislation, and estimates of future taxable income and capital expenditures, that no cash income taxes are to be paid by Kelt in 2023. A higher level of capital expenditures than those currently contemplated for 2023, or further additional acquisitions, could further extend the estimated tax horizon, however higher benchmark commodity prices than those forecasted could reduce 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, 2022. 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$)**
Exploration Costs	7.0
Development Costs	308.8
Corporate Costs	0.8
Capital expenditures, before A&D [(1)]	316.6
Property Acquisition Costs	
Proved	1.0
Unproved	2.5
Corporate Acquisition Costs	
Proved	-
Unproved	-
Capital expenditures, after property acquisitions [(1)]	320.1

Note:
(1) See the non-GAAP and Other Financial Measures section of this Annual Information Form

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, 2022:

Wells[(1)]	**Gross**	**Net**
Development		
Gas	12	12.0
Oil	18	15.4
Service		
Exploratory		
Gas	1	1.0
Total	31	28.4

Note:
(1) Based on Lahee Classification System.

During 2023, Kelt expects to drill wells in all of its core operating divisions, targeting liquids-rich natural gas at Oak/Flatrock in British Columbia and natural gas and light oil in Wembley/Pipestone and Pouce/Progress 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 (2023) as reported in the Sproule Report effective December 31, 2022, 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	7,859	136,916	6,307	36,985
Total Proved Plus Probable	9,421	161,831	7,423	43,816

The Pouce Coupe/Progress property and the Wembley/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, 2022, 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 Wembley/Pipestone property, and the Oak/Flatrock 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	4,327	74,374	1,125	17,848
Total Proved Plus Probable	5,257	90,024	1,351	21,611
Wembley/Pipestone				
Total Proved	3,438	33,481	3,834	12,852
Total Proved Plus Probable	4,067	38,046	4,367	14,775
Oak/Flatrock				
Total Proved	9	21,839	1,278	4,927
Total Proved Plus Probable	10	26,149	1,632	6,000

Production History

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

	2022				
Product	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Light & Medium Crude Oil (Bbl/d)	5,640	6,416	5,192	4,871	6,081
NGLs (Bbl/d)	4,049	3,478	3,906	4,809	4,012
Conventional Natural Gas (Mcf/d)[(1)]	105,280	108,849	100,158	108,199	103,919
Total (BOE/d)	27,236	28,036	25,791	27,713	27,413

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.

	2022				
Category	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Selling prices[(1)], before financial instruments:					
Oil ($/Bbl)[(2)]	117.18	107.88	115.92	135.36	113.60
NGLs ($/Bbl)[(3)]	67.64	60.54	63.59	79.24	63.90
Gas ($/Mcf)[(4)]	6.63	6.52	6.38	8.14	5.41
Average ($/BOE)	59.54	55.91	57.74	69.33	55.09
Selling prices[(1)], after financial instruments:					
Oil ($/Bbl)[(2)]	105.39	106.88	114.89	107.35	93.94
NGLs ($/Bbl)[(3)]	67.64	60.54	63.59	79.24	63.90
Gas ($/Mcf)[(4)]	5.68	6.59	4.17	6.63	5.21
Average ($/BOE)	53.86	57.57	48.97	58.50	49.96
Royalties ($/BOE)[(5)]	6.60	6.15	7.04	7.20	6.02
Transportation and selling expenses:					
Oil ($/Bbl)	2.97	2.78	3.39	2.75	2.97
NGLs ($/Bbl)	0.32	0.63	0.26	0.19	0.26
Gas ($/Mcf)	0.62	0.60	0.64	0.63	0.62
Average ($/BOE)	3.06	3.03	3.22	2.96	3.06
Production expenses[(6)] ($/BOE)	10.22	10.90	10.52	9.82	9.62
Operating netbacks[(7)] ($/BOE)	33.98	37.49	28.19	38.52	31.26

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 Netback" 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 also refers to operating netback expressed per unit of production.

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, 2022 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)	%
Oak/Flatrock	178	940	21,255	4,661	17
Pouce Coupe/Progress	2,553	839	55,113	12,578	46
Wembley/Pipestone	2,820	2,203	21,241	8,563	32
Other	89	67	7,671	1,435	5
TOTAL	5,640	4,049	105,280	27,237	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.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete. The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system applies in provinces and territories that request it to be implemented or are without their own system that meets federal standards. The federal regime was subject to a number of court challenges by Alberta, Saskatchewan and Ontario. The final decision from the Supreme Court of Canada is expected to be delivered sometime in 2021. See "*Industry Conditions – Environmental Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on its profitability and financial condition. Further, the imposition

of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

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.

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

The Corporation uses utilize multi-well pad drilling where practicable. Problems affecting a single well could adversely affect production from all of the wells on the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production, or interruption in ongoing production. These delays or interruptions may cause volatility in our operating results.

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.

Climate Change

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of greenhouse gases, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Climate Change Regulation*" for a summary of Canada's subsequent actions and pledges aimed at reducing Canada's greenhouse gas emissions and environmental impact. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as greenhouse gas emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of greenhouse gas emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in our profitability and a reduction in the value of our assets.

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

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

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. The Corporation is committed to reporting, on the Corporation's sustainability performance, and consider existing standards such as the Global Reporting Initiative Sustainability Reporting Standards, the Sustainability Accounting Standards Board Oil & Gas –Exploration & Production standard, and recommendations issued by the Task Force on

Climate-Related Financial Disclosures. In addition, the Canadian Securities Administrators have published for comment the proposed National Instrument 51-107 –Disclosure of Climate Related Matters, which is intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If the Corporation is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, the business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Climate Change Regulation*".

Physical risks

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. The Corporation does not conduct fundamental research regarding the scientific inquiry of climate change, but do stay abreast of the scientific literature on the subject. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Corporation's ability to access the Corporation's properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Corporation's assets or cause disruptions to the production and transport of the Corporation's products or the delivery of goods and services in the Corporation's supply chain.

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 suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and 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.

Indigenous Claims

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

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. It is possible that lands on which the Corporation operates are, or could in the future become, subject to Indigenous and treaty rights claims (including Indigenous title claims). Any such claims could have a material adverse impact on the Corporation's ability to operate on such lands when the Corporation otherwise intends to or at all, which could in turn have a material adverse impact on the Corporation's financial condition, results of operations and/or growth plans.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the

circumstances and is often the subject of litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect the Corporation's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals.

Kelt is monitoring the impact of the recent Supreme Court of British Columbia judgement in *Yahey v British Columbia* (the "**Blueberry Decision**") with respect to a claim brought forth by the Blueberry River First Nation (the "**BRFN**") against the province of British Columbia regarding the cumulative impact of industrial development within the BRFN treaty claim area. The Blueberry Decision found that the Province of British Columbia breached the Treaty 8 rights of the BRFN by allowing extensive industrial development on the BRFN's traditional territory without first assessing the cumulative impacts of this development on the ability of the members of the BRFN to exercise their Treaty 8 rights to hunt, fish, and trap on their traditional territory. The Blueberry Decision calls for the province of British Columbia to pause some development in the BRFN traditional area pending the results of an investigation into the cumulative impacts of industrial development in the BRFN's traditional territory. The Blueberry Decision gave six months for the Government of British Columbia and the BRFN to negotiate changes to the regulatory regime that recognizes and respects treaty rights.

On January 18, 2023 the Government of British Columbia and the Blueberry announced an agreement which provides a partnership pathway approach to land, water and resource management in the Blueberry traditional territory. The agreement will include new areas which are protected from industrial development (including oil and gas development) and includes new constraints on developments in other areas while a long-term cumulative effects management regime is implemented.

On January 20, 2023 the Government of British Columbia and four of the Treaty 8 First Nations (Fort Nelson, Saulteau, Halfway River and Doig River First Nations) announced that a consensus was obtained on a collaborative approach to land and resource planning within the traditional territories of the four Treaty 8 First Nations. The initiatives set out in the consensus document include new land-use plans and protection measures, additional measures for shared decision making and a new revenue sharing approach.

The Corporation does not currently expect that there will be a significant impact to Kelt's 2023 guidance as a result of the new agreements between the Blueberry, the four Treaty 8 First Nations and the Government of British Columbia. However additional information on these agreements will be required to assess what the short and long term impact will be on the overall development of oil and gas resources in British Columbia.

Volatility in the Oil and Gas Industry

Market events and conditions, including global oil and natural gas supply and demand, world health emergencies (including the ongoing COVID-19 pandemic), 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, hostilities in the Middle East, Ukraine and Taiwan, the occurrence or threat of terrorist attacks in the U.S. or other countries, 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. It is anticipated that the oil and natural gas industry will experience more pressure from investors to take meaningful strides towards combating climate change in the upcoming years, including diversifying their energy portfolios. Russia's invasion of Ukraine has led to sanctions being levied against Russia by the international community and may result in additional sanctions or other international action, any of which may have a destabilizing effect on commodity prices and global economies more broadly. These events and conditions have been a factor in the volatility in the valuation of oil and gas companies. 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 had an effect on, and may continue to have an effect on the Corporation's cash flow which could result in a change to the Corporation's 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 Facility, 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.

Credit Facility

The amount authorized under the Corporation's credit agreement governing the Credit Facility is dependent on the borrowing base determined by its lender. The lender uses 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 Facility. 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; (x) government regulations, actions by the Government of Alberta including, without limitation, imposing, amending, or lifting crude oil production curtailments; and (xi) the impact of regional and/or global health related events, such as the ongoing COVID-19 pandemic, on economic activity levels and energy demand. 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) which replaced NAFTA was ratified on July 1, 2020, see "*Industry Conditions – Trade Agreements*" in this Annual Information Form. In 2021, the Biden administration in the U.S. revoked certain permits required for the construction of the Keystone X.L. pipeline, resulting in the projects cancellation by TC Energy. Future actions taken by the U.S. administration could have a negative

impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union are slowly emerging and some impacts may not become apparent for some time. 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.

Beginning in November 2021, Russia began to amass troops along the Ukrainian border, heightening military tension in Eastern Europe. In February 2022, Russia sent troops into pro-Russian separatist regions in Ukraine. Ongoing military tensions between Russia and Ukraine have the potential to threaten supply of oil and gas from the region and demand from other European countries as well as the possibility that other nations will impose certain tariffs and restrictions on oil from Russia. The long-term impacts of the tension between Russia and the Ukraine remains unclear, including the responses from other nations globally.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The United Conservative Party government in Alberta is supportive of the Trans Mountain Pipeline expansion project and, although there has been notable opposition from the government of British Columbia, the federal Government remains in support of the project. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction.

Following former Alberta Premier Jason Kenney's resignation on May 18, 2022, Danielle Smith was elected as Premier on October 11, 2022. Shortly after her appointment, Premier Smith introduced *Bill 1: The Alberta Sovereignty Within a United Canada Act* (the "**Sovereignty Act**"). The Sovereignty Act was passed on December 8, 2022 and received Royal Assent on December 15, 2022. The Sovereignty Act, amongst other things, enables the Alberta Government to choose which federal legislation, policies or programs it will enforce in Alberta, providing an overriding right to not enforce those which the Alberta Government deems to be " harmful" to Alberta's interests or infringe on the Federal Constitution and its division of powers. The Sovereignty Act has been opposed by many, including the National Democratic Party and various Indigenous groups who have expressed concern as to how the Sovereignty Act will affect Indigenous rights and consultation obligations in Alberta. It is unclear what the effect the Sovereignty Act will have on Alberta, including the petroleum and natural gas industry, Alberta businesses and its federal and interprovincial relationships, including the application of certain federal legislation in Alberta, such as the GGPPA (as defined herein) and the IAA (as defined herein)and the way in which the Alberta Government may address any legislative and policy gaps created. Although the Sovereignty Act has not yet been challenged in court, it is possible the Sovereignty Act's constitutionality will be challenged.

The federal Liberal Government was re-elected in 2021, but continues to hold 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.

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development - particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities.

See "*Industry Conditions – Pipelines*", "*– Crude Oil and Bitumen by Rail*", "*– Trade Agreements*" and "*Climate Change Regulation*" in this Annual Information Form.

COVID-19

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide could have an adverse impact on the Corporation's business, including changes to the way the Corporation and its counterparties operate, and on the Corporation's financial results and condition. At the onset of the COVID-19 pandemic, governments and regulatory bodies in affected areas imposed a number of measures designed to contain the COVID-19 pandemic, including widespread business closures, social distancing protocols, travel restrictions, quarantines, curfews and restrictions on gatherings and events. While substantially all containment measures in Canada have lifted, additional safety precautions and operating protocols aimed at containing the spread of COVID-19 maybe instituted in line with guidance of public health authorities. Additional waives of the COVID-19 pandemic, together with the emergence of new COVID-19 variant strains, may lead to the imposition of containment measures to varying degrees in many regions within Canada and globally. These containment measures in 2022 impacted the global economic activity, including the ability to move towards recovery of the global economy and such measures also contributed to the decreased demand for hydrocarbons, increased market volatility and continued changes to the macroeconomic environment. Although the containment measures are being eased globally, new COVID-19 variants may have an adverse impact on the Corporation's business strategies and initiatives, resulting in negative effects to the Corporation's financial results, including the increase of counterparty, market and operational risks.

The Corporation's business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, be adversely impacted as a result of the pandemic, new COVID-19 variants, and/or decline in commodity prices as a result of: the shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruption or labour shortages caused by workers becoming infected with COVID-19, or government or health authority mandated restrictions on travel by workers or closure of facilities or worksites; suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations; reduced cash flows resulting in less funds from operations being available to fund capital expenditure budgets; reduced commodity prices resulting in a reduction in the volumes and value of reserves; crude oil storage constraints resulting in the curtailment or shutting in of production; counterparties being unable to fulfill their contractual obligations on a timely basis or at all; the inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate; and the ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

Kelt continues to monitor current market conditions resulting from the COVID-19 pandemic. The Corporation's highest priority remains the health and safety of its employees, partners and the communities where it operates. Kelt continues to maintain measures that have been put in place to protect the well-being of these stakeholders and is proud of the dedication of its workforce to maintain safe operations and business continuity in a challenging environment.

Given the uncertainty of the extent and duration of the COVID-19 pandemic, as well as the potential for new COVID-19 variants emerging, the impacts on the economy and the energy business more broadly, as well as the timeline of the transition to a fully reopened economy, the future impact on the Corporation's business and its financial results and condition remains uncertain.

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. Future pipeline projects may be terminated for reasons such as failure to obtain government and/or regulatory support or approval. The direct impact that the termination of such projects will have on the Corporation is unknown. See "*Industry Conditions – Pipelines*".

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada leading to increased awareness of and challenges to interprovincial and international infrastructure projects. In 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency. The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

A portion of the Corporation's production may be processed through facilities owned by third parties and over which the Corporation does not have control. 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, electric vehicle mandates, 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 (including electric vehicles), 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.

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 and deficiencies in internal controls or information technology controls, 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, transportation, infrastructure and mergers and acquisitions). 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 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. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Indigenous consultation, environmental impact assessments, and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. 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, the Corporation's inability to obtain insurance coverage against one or more risks at acceptable premium rates or at all, 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 transportation infrastructure, including 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;
- environmental and Indigenous activism or land claims that potentially result in delays or cancellation of projects;
- litigation and judicial interpretation and application of laws, including with respect to Indigenous rights and historical treaties; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

If Kelt's funds flow and funds from external financing sources are not sufficient to cover the capital expenditure requirements, Kelt may be required to reallocate available capital among its projects or modify its capital expenditure plans, which may result in delays to, or cancellation or, certain projects or deferral of certain capital expenditures. Any change to Kelt's capital expenditure plans could, in turn, have a material adverse effect on Kelt's growth objectives and business, financial position and results of operations. 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

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 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

Kelt may enter into agreements to receive fixed prices on its oil and natural gas production, which is intended to mitigate the effect of commodity price volatility and support Kelt's capital budgeting and expenditure plans; however, if commodity prices increase beyond the levels set in such agreements, Kelt will not benefit from such increases.

On the other hand, failure to protect against a decline in commodity prices exposes Kelt to reduced liquidity when prices decline. A sustained lower commodity price environment would result in lower realized prices for unprotected volumes and reduce the prices at which Kelt would enter into derivative contracts on future volumes. This could make such transactions unattractive, and, as a result, some or all of Kelt's production volumes forecasted for the current fiscal year and beyond may not be protected by derivative arrangements.

Similarly, 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, 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, additional discoveries of hydrocarbon reserves by Kelt's competitors, the cost of production and political and economic factors and other factors outside Kelt's control.

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 commodity prices, historical production from the properties, production rates and estimated production decline rates, estimated ultimate reserve recovery, changes in technology, timing, amount and effectiveness of future 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, 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.

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, from time to time there may be 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.

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, or a dividend as a result of an asset sale. Any future determination to pay dividends will be at the discretion of the Board of Directors 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 of Directors 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 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, securities laws matters, employment matters, 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 Canadian 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.

In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand and the global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic OPEC forecasts robust growth in world oil demand in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

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

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 National Energy Board's (the "**NEB**") 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.

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

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

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 Canadian constitutional law, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval of the cabinet of the Canadian federal government ("**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.

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

In 2021, the Biden administration in the U.S. revoked certain permits required for the construction of the Keystone X.L. pipeline, resulting in the projects cancellation by TC Energy.

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

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

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

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. On November 26, 2021, the CER issued its Reasons for Decision in Enbridge Pipelines Inc. RH-001-2020, denying the application to introduce firm service on the Canadian Mainline. If approved, the application would have made 90% of the Canadian Mainline's currently uncommitted capacity subject to firm contracts for priority access, with contract terms ranging from eight to 20 years. Contracts for firm service were to be awarded through an open season process put forward as part of the application.

Crude Oil and Bitumen by Rail

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. The order was updated in early April 202 and will remain in place until permanent rule changes are approved. As a result, trains subject to the order will be required to adhere to the reduced speed limits announced in February 2020 within metropolitan areas, with further mandatory speed reductions applying outside of metropolitan areas during winter months (November 15 to March 15). As of January 2023, no permanent rules have been approved.

Trade Agreements

The United States-Mexico-Canada Agreement ("**USMCA**") replaced the North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. 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. The United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, therefore the implementation of the USMCA could impact Western Canada's oil and gas industry at large, including Kelt's business.

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 ("**Brexit**") on January 31, 2020, the United Kingdom and Canada have reached an interim post-Brexit trade agreement, the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"). On December 9, 2020, the Government of Canada introduced Bill C-18, an Act to Implement the Trade Continuity Agreement. CETA ceased to apply to Canada-United Kingdom trade on January 1, 2021. The CUKTCA replicates CETA on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship.

In addition, Canada and ten other countries signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**") on March 8, 2018, which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP has been ratified by seven countries, including Canada. As other countries ratify the agreement, they are added to the annexes. The CPTPP facilitates temporary entry to Canada for certain categories of business persons who are citizens of other countries which are signatories to the CPTPP.

While it is uncertain what effect CETA, CUKTCA, 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 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.

The federal and provincial governments also create incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the oil and gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic such as the various short-term loan programs and the Canada Emergency Wage Subsidy, for example, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, Innovation, Science and Economic Development Canada and, in some cases, the Canada Revenue Agency.

Alberta

In Alberta, oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014 to shorten the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three.

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

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

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

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

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

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta

has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

British Columbia

On October 7, 2021, the Government of British Columbia launched a comprehensive review of its oil and gas royalty system. The new oil and gas royalty system (the "**New Framework**") was announced in May 2022. The New Framework will increase the minimum royalty rate from 3% to 5% and eliminate the Deep Well, Marginal Well, Ultra-marginal Well, Low Productivity Well Rate Reduction and Clean Growth Infrastructure royalty programs (the "**Old Royalty Programs**"). New wells drilled under the New Framework will pay the flat royalty of 5% until capital spent on drilling and completions is recovered, at which point they will move to a price-sensitive royalty rate between 5% and 40%, depending on the specific commodity being produced.

Wells drilled on or after September 1, 2022 will not be eligible to qualify for the Old Royalty Programs, and will pay a 5% royalty rate for the equivalent of the first 12 months of production. Following this period, these wells will pay the prevailing price-sensitive royalty rates until September 1, 2024 when all wells will be transitioned to the New Framework. Wells drilled prior to September 1, 2022 will pay royalties based on the current framework until September 1, 2024, at which time those wells will be transitioned to the New Framework and will no longer be able to take advantage of the Old Royalty Programs.

Under the current system, Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales.

Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The Crown royalty rate for oil can be as high 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells under the Old Royalty Program to reflect higher per-unit costs of exploration and extraction. The Crown royalty rate for natural gas and NGLs in British Columbia varies depending on the characteristics of the specific substance and can be as high as 27%, depending on factors such as whether the gas is classified as conservation gas or non-conservation gas, the applicable reference price and select price.

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.

In response to COVID-19, the governments of Alberta and British Columbia have announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures. In March 2020, the British Columbia Ministry of Energy, Mines and Low Carbon Innovation announced that it was suspending posting requests and dispositions of petroleum and natural gas rights until further notice due to COVID-19. In December 2020, the monthly tenure process was resumed.

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). 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.

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. 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* were repealed. In addition, the Impact Assessment Agency of Canada (the "**IA Agency**") replaced the Canadian Environmental Assessment Agency.

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

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto power over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

On December 3, 2020, the Government of Canada tabled Bill C-15 (as defined below). Bill C-15 is the Government of Canada's response to requests to implement the United Nations Declaration of the Rights of Indigenous Peoples as a framework for reconciliation in Canada. On June 21, 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* received Royal Assent and immediately came into force.

Alberta

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

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

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

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

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in Subsurface Order Nos. 2, 6, and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

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 Energy Regulator (the "**BCER**") 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 BCER 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.

In November 2022, the Government of British Columbia passed the *Energy Statutes Amendment Act, 2022* (the "**ESA Act**"). The mandate of the ESA Act was expanded to include oversight of hydrogen, ammonia and methanol. In support of the government's stated desire to transition away from fossil fuels and grow the province's hydrogen industry, the OGAA will also be renamed the *Energy Resource Activities Act* (the "**ERAA**"). In addition to expanding the British Columbia Energy Regulator's jurisdiction to include hydrogen, ammonia and methanol, the updated ERAA will also expand director and officer responsibility for costs associated with orphan sites.

An updated Environmental Assessment Act came into force on December 16, 2019. The amendments 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.

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

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

management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

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

As a result of the Supreme Court of Canada's decision in Orphan Well Association v Grant Thornton (also known as the Redwater decision), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed Bill 12: The Liabilities Management Statutes Amendment Act. Bill 12 places the burden of a defunct licensees' abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes came into force in June 2020.

In response to the increase in orphaned crude oil and natural gas sites and the environmental risks associated therewith, the AER has issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. For example, the AER amended its Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that they can meet their abandonment and reclamation obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

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

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

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with Directive 020: Well Abandonment. The compliance deadline for the final year of the IWCP was extended from April 1, 2020 to September 1, 2020 and was concluded in March of 2021.

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

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

British Columbia

In British Columbia, the BCER has moved away from the formulaic approach to liability management set out in the Liability Management Rating Program, towards a more holistic assessment of a permit holder's ability to meet its abandonment and reclamation obligations. The BCER implemented the Permittee Capability Assessment on April 1, 2022 (the "**BC PCA**"). Under the BC PCA, the financial risk of a permit holder is assessed based on its: (i) assets to liabilities ratio; (ii) net profit margin (three-year average); (iii) interest coverage ratio; (iv cash flow to debt ratio; and (v) debt to equity ratio. A permit holder is assessed on these factors based on the financial information it is required to submit to the BCER intermittently throughout the year. The permit holder is then evaluated on the magnitude or its liabilities, based on the deemed abandonment, assessment, remediation and reclamation liability associated with the permit holder's dormant, inactive and marginal sites. If the BCER deems a permit holder to be high-risk under the BC PCA based on its financial risk and the magnitude of its liabilities, the regulator may require may require that permit holder to engage in corrective action. Correction action could include the submission of security deposits and/or the completion of liability reduction work. Regarding the latter, the BCER will attempt to engage with permit holders to develop corrective action plans prior to issuing corrective action requirements.

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 BCER to impose more than one levy in a given calendar year.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") established 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 BCER, 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.

The Government of British Columbia passed amendments to the *Oil and Gas Activities Act* under the *Miscellaneous Statutes Amendment Act (No.2)* in October 2021. These amendments allow the BCER to grant exemptions for strict compliance with the requirements of the Dormancy Regulation. In turn, this may mean that a permit holder can, with approval, depart from the regulated timelines set out under the Dormancy Regulation. The relevant amendments which provide the BCER with the power to grant these exemptions came into force on October 28, 2021.

The BCER is currently drafting proposed amendments to expand the Dormancy Regulation to include pipelines, facilities and related activities. The comment period on the draft policy changes ended on July 30, 2022. It is unknown when the amended regulation is expected to be implemented.

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. On January 20, 2021, President Biden of the United States signed an executive order to rejoin the Paris Agreement. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada.

In 2016, the Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

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

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

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of carbon dioxide equivalent ("**CO2e**") emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. This ensures that there is a uniform price on emissions across the country. Originally under

current federal plans, this price will escalate by $10 per year until it reached a price of $50/tonne of CO2e in 2022. On December 11, 2020, however, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $65/tonne of CO2e.

Alberta, Saskatchewan, and Ontario referred the constitutionality of the GGPPA to their respective Courts of Appeal. In the Saskatchewan and Ontario references, the appellate Courts found the GGPPA to be constitutional; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments were appealed to the Supreme Court of Canada. The Supreme Court of Canada confirmed the constitutional validity of the GGPPA in a judgment released on March 25, 2021.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the 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.

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act* (the "**CNEAA**") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions-reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada introduced its 2030 Emissions Reduction Plan (the "**2030 ERP**") on March 29, 2022. In the 2030 ERP, the Government of Canada proposes a roadmap for Canada's reduction of GHG emissions to 40-45% below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the oil and gas sector, among other measures.

On June 8, 2022, the *Canadian Greenhouse Gas Offset Credit System Regulations* were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal output-based pricing system through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the output-based pricing system or those seeking to meet voluntary targets.

On June 20, 2022, the *Clean Fuel Regulations* came into force, establishing Canada's Clean Fuel Standard. The Clean Fuel Standard will replace the former *Renewable Fuels Regulation*, and aims to discourage the use of fossil fuels by

increasing the price of those fuels when compared to lower-carbon alternatives. Coming into force in 2023, the Clean Fuel Standard will impose obligations on primary suppliers of transportation fuels in Canada and require fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The *Clean Fuel Regulations* also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

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

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

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 4, 2019, the federal government approved Alberta's proposed Technology Innovation and Emissions Reduction ("**TIER**") regulation, 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 provisions of the TIER regulation required that an interim review of the regulation be completed by December 31, 2022 giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of the carbon pricing systems for 2023 to 2030. Following the comment period, the *Technology Innovation and Emissions Amendment Regulation* was adopted with certain amendments to the TIER Regulation becoming effective January 1, 2023. These amendments include meeting the federal standards for Alberta's carbon pricing system, the creation of sequestration credits for CCUS projects and amendments to the number of credits that can be used to meet emission targets. The TIER regulation is set to undergo another review by December 31, 2026.

The TIER regulation 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. Under the amendments, a 2% annual tightening rate will apply to facility-specific and high performance benchmarks. 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. 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 in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

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. In May 2021, the Government of Alberta announced a competitive bid process under which it would issue rights for carbon sequestration, focusing on the development of strategically placed carbon sequestration hubs, avoiding stand-alone injection operations. As of the fall of 2022, the Government of Alberta approved a total of 25 hub proposals through two competitive bid processes. The selected companies will begin exploring how to safely develop their carbon storage hubs. If a proponent can successfully demonstrate their project can provide permanent storage, companies will have the opportunity to apply for the right to inject captured carbon dioxide at such project. The Government of Alberta has also announced it will invest $40 million in 11 carbon capture and storage hub projects through Emissions Reduction Alberta.

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 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. The fuel charge is currently set at $65/tonne of CO2e, and will continue to increase in line with the GGPPA minimum charge. Federal carbon pricing mechanisms are not currently in force in British Columbia, as the province's programs currently meet or exceed the federal benchmark stringency requirements.

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. Complementing its CleanBC plan, on March 26, 2021, the Government of British Columbia announced a number of sector-specific emissions reduction targets, established with reference to 2007 emissions levels, that it aims to achieve by 2030, including reduction targets of 27-32% for the transportation sector, 38-43% for industry and 33-38% for oil and gas.

The Government of British Columbia established the CleanBC Industry Fund in 2019 to support clean industry development in the province. The fund uses a portion of carbon tax revenue paid by large emitters to invest in projects aimed at reducing greenhouse gas emissions. In March 2021, the Government of British Columbia temporarily increased the provincial share of funding to up to 90% of project costs with a cap of $25 million per project. In 2021, the CleanBC Industry Fund invested $8.35 million in 32 emissions performance projects across British Columbia.

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "**CleanBC Roadmap**"), aimed at helping British Columbia achieve its 2030 emission

reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90% of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries, and for increased support for clean hydrogen and negative emissions technology. Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

In January 2020, the BCER implemented 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. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the UNDRIP and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the Declaration on the Rights of Indigenous Peoples Act ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

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

On June 29, 2021, the British Columbia Supreme Court issued the Blueberry Decision with respect to a claim brought forth by the BRFN against the province of British Columbia regarding the cumulative impact of industrial development within the BRFN treaty claim area. The Blueberry Decision found that the Province of British Columbia breached the Treaty 8 rights of the BRFN by allowing extensive industrial development on the BRFN's traditional territory without first assessing the cumulative impacts of this development on the ability of the members of the BRFN to exercise their Treaty 8 rights to hunt, fish, and trap on their traditional territory.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "**BRFN Agreement**"). The BRFN Agreement aims to address the cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200-million restoration fund by June 2025, an ecosystem-based management approach for future land- use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations –Fort Nelson, Salteau, Halfway River and Doig River First Nations –reached consensus on a collaborative approach to land and resource planning (the "**Consensus Agreement**"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue-sharing approach to support the priorities of Treaty 8 First Nations communities.

In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by the BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. The long-term impacts of the Blueberry Decision and the Duncan's First Nation lawsuit on the Canadian oil and gas industry remain uncertain.

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, special dividends resulting from asset dispositions, 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 192,019,365 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 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	
2022			
January	5.79	4.82	11,929,875
February	5.83	5.24	13,588,290
March	7.15	5.10	20,505,213
April	7.30	6.04	9,781,102
May	7.38	5.88	10,379,507
June	8.32	5.60	13,674,118
July	6.95	4.93	8,550,066
August	6.85	6.02	7,598,871
September	6.61	4.98	7,170,046
October	6.18	5.31	6,241,490
November	6.55	5.19	9,270,886
December	5.60	4.67	7,061,385
2023			
January	5.16	4.47	13,058,367
February	4.81	4.29	10,982,326
March 1	4.92	4.70	369,832

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, 2022 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	$5.34	3,332,500	March 17, 2022
Options	$6.97	10,000	March 18, 2022
Options	$6.54	20,000	May 27, 2022
Options	$7.22	10,000	June 6, 2022
Options	$6.73	60,000	June 20, 2022
Options	$6.21	75,000	August 18, 2022
Options	$5.57	10,000	November 17, 2022
Options	$5.44	10,000	December 5, 2022
RSUs	$5.34	167,000	March 17, 2022
RSUs	$6.97	3,000	March 18, 2022
RSUs	$6.54	5,000	May 27, 2022
RSUs	$7.22	3,000	June 6, 2022
RSUs	$6.73	6,000	June 20, 2022
RSUs	$6.21	10,000	August 18, 2022
RSUs	$5.57	3,000	November 17, 2022
RSUs	$5.44	3,000	December 5, 2022

As at the date of this Annual Information Form, the Corporation has 10,662,121 Options and 890,500 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
Douglas J. Errico[9] Alberta, Canada	Senior Vice President, Land & Corporate Development since October 22, 2012	Senior Vice President, Land & Corporate Development of Kelt since November 9, 2020 and prior thereto Vice President, Land of Kelt since October 22, 2012. 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.
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.
Geraldine L. Greenall[1][4][5][6] 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	Director since October 22, 2012	Retired. Partner with Borden Ladner Gervais LLP until December 2020.
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.
Louise K. Lee Alberta, Canada	Corporate Secretary since November 9, 2020	Partner with Borden Ladner Gervais LLP.
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.
Janet Vellutini[1][2][4]	Director since July 1, 2021	Retired. Previously, a Marketing Consultant with Black Swan Energy, a Calgary-based private energy company until June 2021.
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.

(9) On November 9, 2020, Mr. Errico was appointed Senior Vice President, Land & Corporate Development and prior thereto, was Vice President, Land since October 22, 2012.

Each of the directors of Kelt will hold office until the next 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 35.5 million Common Shares, representing approximately 18% of the issued and outstanding Common Shares. 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, 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.

The Corporation's auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have prepared an independent auditor's report dated March 2, 2023 in respect of the Corporation's consolidated financial statements as at December 31, 2022 and December 31, 2021 and for the years then ended. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

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 19, 2023 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, 2022 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, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation 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 (the "**COGE Handbook**"), as amended and 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, 2022, 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	December 31, 2022	Canada	42,474	3,387,640	Nil	3,430,114
Total						

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, 2022)."

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 9, 2023

(signed) "*Cameron P. Six*"
Cameron P. Six, P. Eng.
Senior Petroleum Engineer

(signed) "*Doug Ashton*"
Doug Ashton, P. Eng.
VP, Reservoir Services

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, 2022, 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) "*Geri L. Greenall*"
Geri L. Greenall
Director

Dated this 16th day of February, 2023.

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 (the "**COGE Handbook**"), as amended and 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.

1. 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.

2. 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.

3. 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.

4. 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.

5. 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.

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

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

8. 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.

9. **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.

10. **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.

11. **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.

12. **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.

13. **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.

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

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

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

17. **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.

18. **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
Geraldine L. Greenall	Independent(1)	Financially literate(2)
Neil Sinclair	Independent(1)	Financially literate(2)
Janet Vellutini	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

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 3 years of public issuer experience as a director. Ms. Greenall is also the Chief Financial Officer of a publicly listed exploration and production corporation.

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 48 years. He also has over 19 years of public company experience as an officer and as a director.

Ms. Vellutini is a professional engineer and has extensive experience in gas marketing and most recently was a Marketing Consultant at a Calgary-based private energy company. She has over 30 years of experience in gas marketing and a total of 36 years in the oil and gas industry.

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)
December 31, 2022	$234,000	$51,000	$26,400
December 31, 2021	$201,800	$45,000	$24,000

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

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 to fulfill its responsibilities.