PEYTO

Exploration & Development Corp.

REVISED ANNUAL INFORMATION FORM

2019

April 9, 2020

TABLE OF CONTENTS

Page

NOTICE TO READER

This Notice to Reader accompanies this revised Annual Information Form (this "**Annual Information Form**") for Peyto Exploration & Development Corp. dated April 9, 2020 for the year ended December 31, 2019. This Annual Information Form supersedes and replaces the annual information form for Peyto Exploration & Development Corp. dated March 20, 2020 for the year ended December 31, 2019, which was filed on SEDAR on March 25, 2020 (the "**Original AIF**").

This Annual Information Form corrects certain proved and proved plus probable reserves amounts, as well as related updates to certain dollar amounts, in the following tables of the Original AIF: (i) the table entitled "Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue as of December 31, 2019 Forecast Prices and Costs" on page 9 of the Original AIF; (ii) the table entitled "Net Present Values of Future Net Revenue" on page 10 of the Original AIF; (iii) the table entitled "Total Future Net Revenue (Undiscounted) as of December 31, 2019" on page 10 of the Original AIF; (iv) the table entitled "Future Net Revenue by Product Type as of December 31, 2019" on page 10 of the Original AIF; (v) the two tables under the heading "*Statement of Reserves Data and Other Oil and Gas Information – Reconciliations of Changes in Reserves and Future Revenue*" on pages 14 and 15 of the Original AIF; (vi) the table entitled "2019 Finding, Development and Acquisition Costs Company Interest Reserves (Forecast Prices and Costs)" on page 17 of the Original AIF; and (vii) the table entitled "Three Year Historical Finding, Development and Acquisition Costs $/BOE" on page 18 of the Original AIF. Additionally, (i) the Report on Management and Directors on Reserves Data and Other Information on Form 51-101F3 attached as Schedule A to this Annual Information Form has been updated to reflect an updated date of April 6, 2020; and (ii) the Report on Reserves Data by InSite Petroleum Consultants Ltd. on Form 51-101F2 attached as Schedule B to this Annual Information Form has been updated to reflect an amended report prepared April 6, 2020 in respect of an increase in the net present value of future net revenue included in the reserves data evaluated from $4,122,275.1 to $4,125,263.4 (Cdn.$ thousands before income taxes at a 10% discount rate).

Other than as expressly set forth above, this Annual Information Form does not, and does not purport to, update or restate the information in the Original AIF or reflect any events that occurred after the date of the Original AIF.

GLOSSARY OF TERMS

"**2008 Arrangement**" means the arrangement under the provisions of section 193 of the ABCA among the Trust, its subsidiaries and Unitholders which was completed on January 1, 2008 pursuant to which the Internal Reorganization was completed;

"**2010 Arrangement**" means the arrangement under the provisions of section 193 of the ABCA among the Trust, POT, Peyto AdminCo, the Peyto Partnership, PEDC, Peyto Exploration (2011) Ltd. and Unitholders which commenced on December 31, 2010 and was completed on January 1, 2011 and resulted in the reorganization of the Trust into a public, dividend paying, oil and natural gas exploration and development company that acquired all of the assets and assumed all of the liabilities of the Trust;

"**2012 Amalgamation**" means the amalgamation of Peyto and Open Range, its wholly-owned subsidiary, effective December 31, 2012 pursuant to subsection 184(1) of the ABCA;

"**2012 Arrangement**" means the arrangement under the provisions of section 193 of the ABCA among Peyto, Open Range and the shareholders of Open Range which was completed on August 14, 2012 and resulted in Peyto acquiring all of the issued and outstanding common shares of Open Range;

"**2015 Senior Notes**" means the $100 million senior unsecured notes issued on May 1, 2015, which bear a coupon rate of 4.26%, which interest is payable semi-annually in arrears, and mature in May 2025;

"**2016 Senior Notes**" means the $100 million senior unsecured notes issued on October 24, 2016, which bear a coupon rate of 3.7%, which interest is payable semi-annually in arrears, and mature in October 2023;

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

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

"**Direct Royalties**" means royalty interests in petroleum and natural gas rights acquired by Peyto from time to time;

"**InSite**" means InSite Petroleum Consultants Ltd., independent oil and gas reservoir engineers of Calgary, Alberta;

"**InSite Report**" means the independent engineering evaluation of Peyto's oil, NGLs and natural gas interests prepared by InSite dated February 19, 2020 and effective December 31, 2019, a summary of which is contained herein;

"**Internal Reorganization**" means the reorganization of the Trust's subsidiaries effective January 1, 2008, whereby all of the oil and natural gas assets and liabilities of the PEDC entities were transferred to the Peyto Partnership;

"**oil and natural gas properties**" means the working, royalty or other interests of Peyto from time to time in any petroleum and natural gas rights, tangibles and miscellaneous interests, including the properties in which Peyto has an interest as at the date hereof, and properties which may be acquired by Peyto at a future date, and including the Direct Royalties;

"**Open Range**" means Open Range Energy Corp., a corporation incorporated under the ABCA;

"**PEDC**" means Peyto Exploration & Development Corp., a corporation amalgamated under the ABCA and a predecessor to Peyto;

"**Peyto**", the "**Corporation**", "**we**", "**us**" or "**our**" means, as the context requires, (i) Peyto Exploration & Development Corp., a corporation amalgamated under the ABCA on December 31, 2012 pursuant to the 2012 Amalgamation; (ii) Peyto Exploration & Development Corp., a corporation amalgamated under the ABCA on January 1, 2011 pursuant to the 2010 Arrangement; or (iii) the Trust, and its controlled entities on a consolidated basis, prior to the completion of the 2010 Arrangement;

"**Peyto AdminCo**" means Peyto Energy Administration Corp., a corporation incorporated under the ABCA;

"**Peyto Partnership**" means Peyto Energy Limited Partnership, a limited partnership formed pursuant to the laws of the Province of Alberta;

"**POT**" means Peyto Operating Trust, a trust established under the laws of Alberta pursuant to the amended and restated trust indenture dated January 1, 2008 between Valiant Trust Company, the Trust and Peyto AdminCo;

"**Shareholders**" means holders of Common Shares;

"**Trust**" means Peyto Energy Trust, a trust established under the laws of Alberta and predecessor to Peyto. All references to the "Trust", unless the context otherwise requires, are references to Peyto Energy Trust and its controlled entities on a consolidated basis prior to completion of the 2010 Arrangement;

"**Trust Units**" means previously outstanding trust units of the Trust, each unit representing an equal undivided beneficial interest therein;

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

"**United States**" or "**U.S.**" means the United States of America; and

"**Unitholders**" means the former holders of the Trust Units.

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

Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrels	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Mcf/d	thousand cubic feet per day
NGLs	natural gas liquids	MMcf/d	million cubic feet per day
Mboe	thousand barrels of oil equivalent	m^3	cubic metres
MMboe	million barrels of oil equivalent	MMbtu	million British Thermal Units
boe/d	barrels of oil equivalent per day	GJ	Gigajoule
bbls/d	barrels of oil per day		

Other

BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.**
McfGE	means thousand cubic feet of natural gas equivalent, using the conversion factor of one bbl of oil to 6 Mcf of natural gas. **McfGEs may be misleading, particularly if used in isolation. An McfGE conversion ratio of 1 bbl:6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 1 bbl: 6 Mcf, utilizing a conversion on a 1 bbl: 6 Mcf basis may be misleading as an indication of value.**
WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
M$	means thousands of dollars.
MM$	means millions of dollars.
km	means kilometres.

CONVERSION

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
GJ	MMbtu	0.950

ADVISORY

YOU SHOULD NOT RELY ON FORWARD-LOOKING STATEMENTS BECAUSE THEY ARE INHERENTLY UNCERTAIN.

Certain statements contained in this Annual Information Form constitute forward-looking statements or forward-looking information (collectively, "**forward-looking statements**") within the meaning of applicable Canadian securities laws. These forward-looking statements relate to future events or Peyto's future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. These statements speak only as of the date of this Annual Information Form.

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

In particular, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics of the oil and natural gas assets of Peyto;
- oil and natural gas production levels;
- market prices for oil and natural gas, including pricing assumptions used in the Reserves Data (as defined herein);
- the size of Peyto's oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of dividends;
- supply and demand for oil and natural gas;
- the effects the 2019 novel coronavirus ("**COVID-19**") pandemic;
- expectations regarding the ability to raise capital and to continually add to reserves through exploration and development and, if applicable, acquisitions;
- treatment under governmental regulatory regimes;
- capital expenditures programs;
- the payment of dividends;
- the existence, operation and strategy of Peyto's commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed by Peyto;
- Peyto's future tax horizons;
- the impact of Canadian federal and provincial governmental regulation on Peyto; and
- the goal to grow or sustain production and reserves through prudent exploration, management and acquisitions.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- public health risks including the COVID-19 pandemic;
- volatility in market prices for oil and natural gas;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- loss of markets;
- changes to the Corporation's capital budget;

- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- risks and uncertainties associated with Peyto's oil and natural gas exploration and development program;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling and processing problems;
- restrictions and/or limitations on transportation, including pipeline systems;
- uncertainties associated with changes in legislation, including, but not limited to, changes in income tax laws, oil and natural gas royalty and regulatory frameworks and climate change laws and frameworks; and
- the other factors discussed under "*Risk Factors*".

Statements relating to reserves are deemed to be forward-looking statements as they involve the implied assessment, based on current estimates and assumptions, that the reserves described can be profitably produced in the future. The foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Peyto does not undertake any obligation to publicly update or revise any forward-looking statements, except as required by applicable securities law.

PEYTO EXPLORATION & DEVELOPMENT CORP.

General

Peyto is a Calgary, Alberta based company founded in 1998. Peyto is a growth oriented, dividend paying publicly traded company engaged in the acquisition, exploration, development and production of oil and natural gas in Western Canada. The head and principal office of Peyto is located at Suite 300, 600 – 3rd Avenue S.W., Calgary, Alberta T2P 0G5. The registered office of Peyto is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

The Common Shares trade on the TSX under the symbol "PEY".

Corporate History

PEDC was founded in 1998 as an oil and natural gas exploration and development company.

The Trust was formed on May 22, 2003 and commenced operations on July 1, 2003 as a result of the completion of an arrangement under the provisions of section 193 of the ABCA among PEDC, Peyto Acquisition Corp. and the Trust which was completed on July 1, 2003 and pursuant to which former holders of common shares of PEDC received Trust Units and PEDC became an indirect subsidiary of the Trust.

On January 1, 2008, the Trust completed the 2008 Arrangement. As a result of the Internal Reorganization, all of the oil and natural gas assets of the Trust were held in the Peyto Partnership, Peyto AdminCo was the administrator of the Trust and POT and PEDC was the general partner of the Peyto Partnership prior to completion of the 2010 Arrangement. Certain subsidiaries of the Trust were amalgamated pursuant to the Internal Reorganization.

On January 1, 2011, the Corporation completed the 2010 Arrangement pursuant to which Peyto, directly or indirectly, acquired all of the assets and assumed all of the liabilities of the Trust. Prior to completion of the 2010 Arrangement, the Trust was a reporting issuer in all provinces of Canada and the Trust Units were listed for trading on the TSX. Following completion of the 2010 Arrangement, the Common Shares were listed for trading on the TSX concurrent with the delisting of the Trust Units, the Trust ceased to be a reporting issuer and Peyto became a reporting issuer as successor to the Trust in those jurisdictions in which the Trust was previously a reporting issuer. Pursuant to the terms of the 2010 Arrangement, Unitholders received one Common Share for each Trust Unit held.

On December 31, 2012, Peyto completed the 2012 Amalgamation pursuant to which Peyto amalgamated with Open Range, its wholly-owned subsidiary.

Inter-Corporate Relationships

Peyto has one wholly-owned subsidiary, Peyto LNG Ltd., which was incorporated in the Province of Alberta.

GENERAL DEVELOPMENT OF THE BUSINESS

General

Peyto is a Calgary, Alberta based dividend paying energy company which has been engaged in the acquisition, exploration, development and production of oil and natural gas in Western Canada since it was founded in 1998. Peyto's strategy is to enhance Shareholder value through the exploration, discovery and low cost development of oil and natural gas in the Western Canadian sedimentary basin. Peyto's portfolio of assets includes exploration, exploitation and development opportunities located primarily in the Deep Basin of Alberta. Management's current model is designed to deliver a superior total return with growth in value, assets, production and income, all on a debt adjusted per share basis. The model is built around three key strategies:

- Use technical expertise to achieve the best return on capital employed through the development of internally generated drilling projects;
- Build an asset base which is made up of high quality natural gas reserves; and
- Over time, balance dividends to shareholders paid with earnings, and cash flow, and balance funding for the capital program with cash flow, equity and available bank lines.

Three Year History

The following is a summary of the development of Peyto's business for the periods shown.

2017

During 2017, Peyto drilled or participated in 142 gross (138 net) oil and natural gas wells. 141 wells (137 net) reached total depth as at December 31, 2017. Seven of the 142 gross wells were drilled vertically with the remaining 135 wells drilled horizontally and completed using multi-stage fracturing technology. Capital expenditures for 2017 totalled $521.2 million. The average production for the year was 102,614 boe/d (consisting of 559.7 MMcf/d gross natural gas and 9,337 bbls/d natural gas liquids) and the exit rate was 115,000 boe/d (consisting of 625.0MMcf/d gross natural gas and 10,826bbls/d natural gas liquids).

In 2017, Peyto had earnings of $176.6 million and paid total dividends to Shareholders of $217.6 million.

2018

During 2018, Peyto drilled or participated in 70 gross (67.25 net) oil and natural gas wells. 70 wells (67.25 net) reached total depth as at December 31, 2018. All of the wells were drilled horizontally and completed using multi-stage fracturing technology. Capital expenditures for 2018 totalled $232.3 million. The average production for the year was 92,012 boe/d (consisting of 493.9MMcf/d gross natural gas and 9,692 bbls/d natural gas liquids) and the exit rate was 94,000 boe/d (consisting of 492.8 MMcf/d gross natural gas and 11,869 bbls/d natural gas liquids).

On January 2, 2018, Peyto completed a private placement of an aggregate of $100 million senior unsecured notes (the "**2018 Senior Notes**"). The 2018 Senior Notes have a coupon rate of 3.95%, which interest is payable semi-annually in arrears, and mature on January 2, 2028. The 2018 Senior Notes were issued pursuant to a note purchase agreement and a note purchase and private shelf agreement dated January 2, 2018 between Peyto and a certain institutional investor and rank equally with Peyto's obligations under its bank facility and existing Senior Notes, including the 2015 Senior Notes and the 2016 Senior Notes.

On January 11, 2018, Peyto announced that, starting with the January 2018 dividend, the Corporation's monthly dividend would be reduced from $0.11 per Common Share to $0.06 per Common Share.

Additionally on January 11, 2018, Peyto announced its intention to file a notice of intention with the TSX to make a normal course issuer bid to purchase up to 12,158,897 Common Shares (approximately 10% of the public float of the Common Shares at the time of announcement) through the facilities of the TSX. The normal course issuer bid commenced on January 22, 2018 and expired on January 21, 2019. No Common Shares were purchased under the normal course issuer bid.

On February 1, 2018, Mr. Jean-Paul Lachance was appointed Vice President, Engineering and Chief Operating Officer and Mr. Scott Robinson was appointed Executive Vice President, New Ventures.

In 2018, Peyto had earnings of $129.1 million and paid total dividends to Shareholders of $118.7 million.

2019

During 2019, Peyto drilled or participated in 61 gross (53 net) oil and natural gas wells. 59 wells (51 net) reached total depth as at December 31, 2019. Capital expenditures for 2019 totalled $206.4 million. The average production for the year was 80,802 boe/d (consisting of 419.3 MMcf/d natural gas and 10,922 bbls/d natural gas liquids) and the exit rate was 82,000 boe/d (consisting of 416.9 MMcf/d gross natural gas and 12,511 bbls/d natural gas liquids).

On January 3, 2019, Peyto completed a private placement of an aggregate of $100 million senior unsecured notes (the "**2019 Senior Notes**"). The 2019 Senior Notes have a coupon rate of 4.39%, which interest is payable semi-annually in arrears, and mature on January 3, 2026. The 2019 Senior Notes were issued pursuant to a note purchase agreement dated January 3, 2019 between Peyto and a certain institutional investor and rank equally with Peyto's obligations under its bank facility and existing Senior Notes, including the 2015 Senior Notes, the 2016 Senior Notes and the 2018 Senior Notes. Proceeds from the issuance of 2019 Senior Notes were used to repay the $100 million senior unsecured notes which matured on January 3, 2019.

On January 16, 2019, Peyto announced that, starting with the January 2019 dividend, the Corporation's monthly dividend would be temporarily reduced from $0.06 per Common Share to $0.02 per Common Share.

On January 25, 2019, Peyto announced that the TSX had accepted the Corporation's notice of intention to commence a normal course issuer bid to purchase up to 12,400,000 Common Shares (approximately 10% of the public float of the Common Shares at the time of announcement) through the facilities of the TSX. The normal course issuer bid commenced on January 30, 2019 and expired on January 29, 2020. No Common Shares were purchased under the normal course issuer bid.

On February 1, 2019, Mr. Scott Robinson, Executive Vice President, New Ventures, retired as an officer of the Corporation and began working on a consulting basis.

On May 9, 2019, Mr. John W. Rossall was elected as a new director of the Corporation at the Corporation's annual and special meeting of Shareholders.

On October 25, 2019, Peyto voluntarily repaid $120 million of senior unsecured notes due December 4, 2020.

On November 11, 2019, Mr. Scott Robinson re-joined the Peyto management team in the role of Vice President, Business Development.

On December 18, 2019, Peyto voluntarily repaid $50 million of senior unsecured notes due July 3, 2022 and $35 million of 2015 Senior Notes. In addition, Peyto's senior debt to EBITDA covenant was amended effective December 31, 2019 to 3.5 times. This covenant is scheduled to revert to 3.25 for the fiscal quarter ending December 31, 2021.

In 2019, Peyto had earnings of $133.5 million and paid total dividends to Shareholders of $39.6 million.

Recent Developments

In light of global reaction to the COVID-19 pandemic and the resultant reduction in oil demand, compounded by OPEC+, led by Saudi Arabia and Russia, failing to reach an agreement on constraining output in face of lower global demand to support global oil prices and the stated intention of certain OPEC member countries to discount future deliveries and increase crude oil supply into the market, the Corporation plans to balance its capital program with its cashflows.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Peyto is a growth oriented, dividend paying publicly traded company engaged in the acquisition, exploration, development and production of oil and natural gas in Western Canada.

Principal Properties

See "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Oil and Gas Properties*".

Competitive Conditions

The oil and natural gas industry is competitive in all its phases. Peyto competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Peyto's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of Peyto. Peyto's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources. Peyto believes that it has a competitive advantage to that of other oil and natural gas issuers of similar size, involved in similar areas and at a similar stage of development as a result of Peyto's low cost development of its oil and natural gas properties.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below (the "**Statement**") is dated April 6, 2020. The effective date of the Statement is December 31, 2019 and the preparation date of the Statement is April 6, 2020. The Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 and the Report on Reserves Data by InSite on Form 51-101F2 are attached as Schedules A and B, respectively, to this Annual Information Form.

Disclosure of Reserves Data

The Statement set forth below discloses the Corporation's reserves data (the "**Reserves Data**") is based upon an evaluation by InSite with an effective date of December 31, 2019 contained in the InSite Report. The Reserves Data summarizes the oil, liquids and natural gas reserves of Peyto and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms to the requirements of National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and is in accordance with the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. Peyto engaged InSite to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Peyto's reserves are in Canada, specifically, in the province of Alberta.

Some values set forth below may not add due to rounding.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material.

Reserves Data (Forecast Prices and Costs)

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

	RESERVES									
	Light and Medium Oil		Solution Gas		Conventional Gas		Natural Gas Liquids		Total BOE	
Reserves Category	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved										
Developed Producing	30.7	28.5	-	-	1,366,079	1,266,615	38,926.3	31,554.9	266,636.7	242,685.9
Developed Non-Producing	-	-	-	-	33,610	30,931	1,111.7	896.9	6,713.3	6,052.1
Undeveloped	-	-	-	-	1,255,988	1,173,640	44,636.7	39,048.5	253,968.0	234,655.3
Total Proved	30.7	28.5	-	-	2,655,676	2,471,186	84,674.7	71,500.3	527,318.0	483,393.2
Probable	5.9	5.2	-	-	1,492,769	1,395,870	38,628.8	32,390.9	287,429.6	265,041.1
Total Proved Plus Probable	36.6	33.6	-	-	4,148,445	3,867,057	123,303.5	103,891.2	814,747.6	748,434.3

Note:

(1) Numbers may not add due to rounding.

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
Reserves Category	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved										
Developed Producing	4,319,367	2,745,395	1,971,446	1,538,947	1,268,780	3,598,300	2,364,960	1,740,736	1,385,376	1,159,831
Developed Non-Producing	89,504	56,857	39,252	29,056	22,677	68,561	43,706	30,194	22,368	17,482
Undeveloped	3,721,493	1,835,691	977,210	532,897	279,769	2,849,067	1,367,823	685,438	331,905	131,677
Total Proved	8,130,363	4,637,943	2,987,908	2,100,900	1,571,226	6,515,929	3,776,490	2,456,368	1,739,649	1,308,990
Probable Additional	4,956,375	2,184,859	1,137,356	652,721	395,135	3,794,416	1,651,821	833,575	455,231	255,625
Total Proved Plus Probable	13,086,738	6,822,802	4,125,263	2,753,621	1,966,362	10,310,345	5,428,310	3,289,943	2,194,880	1,564,615

Note:

(1) Numbers may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2019

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment and Reclamation Costs(1) (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved Reserves	15,773,331	1,382,661	3,731,752	2,106,760	421,794	8,130,363	1,614,434	6,515,929
Proved Plus Probable Reserves	24,861,750	2,180,770	5,495,570	3,547,264	551,408	13,086,738	2,776,393	10,310,345

Notes:

(1) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that reserves have been attributed to. See "*Additional Information Concerning Abandonment and Reclamation Costs*".

(2) Numbers may not add due to rounding.

FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2019

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (Discounted At 10%/Year) (M$)	($/bbl or $/Mcf)
Proved Reserves	Light and Medium Crude Oil(1)	514	19.23
	Heavy Oil(1)	-	-
	Natural Gas Liquids	-	-
	Conventional Natural Gas(2)	2,765,358	1.12
Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	579	18.37
	Heavy Oil(1)	-	-
	Natural Gas Liquids	-	-
	Conventional Natural Gas(2)	3,786,870	0.98

Notes:

(1) Including solution gas and other by-products.

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

(3) Unit values are based on net reserve volumes.

(4) Net revenue does not include other income (i.e. processing income).

Definitions and Other Notes

In the tables set forth in this Statement and elsewhere in this Annual Information Form, the following definitions and other notes are applicable.

1. "**Gross**" means:

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

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

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

2. "**Net**" means:

   (a) in relation to Peyto's interest in production and reserves, its "Peyto net reserves", which are Peyto's interest (operating and non-operating) share after deduction of royalties obligations, plus Peyto's royalty interest in production or reserves;

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

   (c) in relation to Peyto's interest in a property, the total area in which Peyto has an interest multiplied by the working interest owned by Peyto.

3. Definitions used for reserve categories are as follows:

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

Reserve Categories

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:

   (a) analysis of drilling, geological, geophysical and engineering data;

   (b) the use of established technology; and

   (c) specified economic conditions (see the discussion of "*Economic Assumptions*" below).

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

   (a) 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.

   (b) 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.

"Economic Assumptions" will be the prices and costs used in the estimate, namely forecast prices and costs.

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

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

      (i) 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.

      (ii) 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.

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

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.

Levels of Certainty for Reported Reserves

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

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

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

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

4. Forecast prices and costs

Future prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which Peyto is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "*Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions*" identifies benchmark reference pricing that apply to Peyto.

5. Future income tax expenses estimate:

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to Peyto's oil and natural gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

6. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

7. "**Development well**" means a well drilled inside the established limits of an oil and natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

8. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

9. "**Exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

10. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

11. Numbers may not add due to rounding.

12. The estimates of future net revenue presented in the tables above do not represent fair market value.

Pricing Assumptions

The following sets forth the benchmark reference prices, as at December 31, 2019, reflected in the Reserves Data. These price assumptions were provided to Peyto by InSite, Peyto's independent qualified reserves evaluator.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

	OIL				NATURAL GAS LIQUIDS					
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Western Canada Select ($Cdn/bbl)	Natural Gas Aeco C Gas Price ($Cdn/MMBtu)	Condensate ($Cdn/bbl)	Butane ($Cdn/bbl)	Propane ($Cdn/bbl)	Ethane ($Cdn/bbl)	Inflation Rates(1) %/Year	Exchange Rate(2) ($US/$Cdn)
Forecast										
2020	61.00	73.26	58.76	2.05	76.93	40.29	27.84	5.77	2.0	1.316
2021	64.50	76.77	62.07	2.32	80.22	46.06	31.47	6.62	2.0	1.299
2022	66.50	78.76	64.26	2.60	82.30	51.19	33.08	7.48	2.0	1.282
2023	68.20	80.00	66.00	2.69	84.40	52.00	34.40	7.76	2.0	1.250
2024	69.90	82.38	68.10	2.81	86.91	53.54	35.63	8.15	2.0	1.250
2025	71.50	84.38	69.81	2.94	89.44	54.84	36.70	8.54	2.0	1.250
2026	73.50	86.88	72.02	3.00	92.09	56.47	37.79	8.72	2.0	1.250
2027	74.97	88.61	73.46	3.06	93.93	57.60	38.77	8.91	2.0	1.250
2028	76.47	90.38	74.93	3.12	95.81	58.75	39.77	9.10	2.0	1.250
2029	78.00	92.19	76.43	3.18	97.72	59.93	40.56	9.30	2.0	1.250
Thereafter	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2.0	1.250

Notes:

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

Weighted average historical prices realized by Peyto for the year ended December 31, 2019 were $2.04/Mcf for conventional natural gas and $44.61/bbl for crude oil and natural gas liquids.

Reconciliations of Changes in Reserves and Future Revenue

RECONCILIATION OF PEYTO GROSS (WORKING INTEREST) RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

	Light and Medium Crude Oil(1)			Conventional Natural Gas(2)			Natural Gas Liquids		
Factors	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2018	70	27	96	2,690,076	1,423,915	4,113,991	67,907	49,136	117,042
Extensions	-	-	-	118,361	96,185	214,545	7,949	4,545	12,494
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revision	(32)	(21)	(52)	(52,114)	3,301	(48,814)	10,453	(14,549)	(4,096)
Infill Drilling	-	-	-	39,323	3,344	42,667	1,610	588	2,198
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Category Transfer	-	-	-	33,497	(35,923)	(2,425)	1,172	(1,215)	(42)
Economic Factors	-	-	-	(20,456)	1,946	(18,510)	(435)	123	(312)
Production	(6)	-	(6)	(153,025)	-	(153,025)	(3,982)	-	(3,982)
December 31, 2019	32	6	38	2,655,663	1,492,766	4,148,429	84,674	38,629	123,303

Notes:

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

RECONCILIATION OF PEYTO NET RESERVES (NET OF ROYALTIES) BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

	Light and Medium Crude Oil(1)			Conventional Natural Gas(2)			Natural Gas Liquids		
Factors	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
December 31, 2018	64	24	88	2,499,449	1,322,298	3,821,748	56,550	40,768	97,318
Extensions	-	-	-	111,036	90,389	201,424	6,864	3,715	10,579
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revision	(31)	(19)	(50)	(47,022)	7,632	(39,390)	8,348	(12,176)	(3,828)
Infill Drilling	-	-	-	36,336	3,020	39,356	1,402	460	1,862
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Category Transfer	-	-	-	31,764	(34,060)	(2,296)	1,053	(1,093)	(39)
Economic Factors	-	-	-	(15,768)	6,588	(9,180)	690	716	1,406
Production	(4)	-	(4)	(144,620)	-	(144,620)	(3,406)	-	(3,406)
December 31, 2019	29	5	35	2,471,174	1,395,867	3,867,041	71,500	32,391	103,891

Notes:

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

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation in the three most recent financial years.

Proved Undeveloped Reserves

Peyto's proved undeveloped reserves are comprised mainly of wells that are budgeted and scheduled to be drilled in the next seven years. Peyto also has proved undeveloped reserves behind pipe (mostly up-hole zones) which will be brought on production once the primary zones have been depleted. Where there is economical justification to accelerate production from secondary zones, Peyto will often proceed to re-complete the subject wellbores or drill twin wells for secondary zones.

	Light and Medium Crude Oil(1) (Mbbl)		Conventional Natural Gas(2) (MMcf)		Natural Gas Liquids (Mbbl)	
Year	1st Attributed	Cumulative at Year-End (1)	1st Attributed	Cumulative at Year-End (1)	1st Attributed	Cumulative at Year-End (1)
2017	-	-	225,751	854,114	3,019	14,238
2018	-	-	275,815	1,120,865	10,219	30,774
2019	-	-	133,830	1,173,640	7,655	39,049

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Cumulative at Year-End = Residual Cumulative of Previous Year plus 1st Attributed.

Probable Undeveloped Reserves

Peyto's probable additional reserves are comprised of performance wedges from producing wells (approximately 17%), step out drilling locations and bypassed zones, which are deemed too probabilistic to be classified as proved. Peyto typically assigns probable reserves to undrilled locations that are scheduled to be drilled in the next seven years. Peyto has historically been successful converting these probable assignments to proven producing entities.

	Light and Medium Crude Oil[1] (Mbbl)		Conventional Natural Gas[2] (MMcf)		Natural Gas Liquids (Mbbl)	
Year	1st Attributed	Cumulative at Year-End [1]	1st Attributed	Cumulative at Year-End [1]	1st Attributed	Cumulative at Year-End [1]
2017	-	-	201,159	865,620	4,180	18,161
2018	-	-	84,272	883,325	3,537	21,149
2019	-	-	66,659	895,955	2,705	22,006

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas and by-products from oil wells.
(3) Unit values are based on net reserve volumes.
(4) Cumulative at Year-End = Residual Cumulative of Previous Year plus 1st Attributed.

A number of factors that could result in delayed or cancelled development are as follows:

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

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

Significant Factors or Uncertainties

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

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

While we do not anticipate any significant economic factors or significant uncertainties will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Future Development Costs

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

Year	Forecast Prices and Costs: Proved Reserves 0% (M$)	Forecast Prices and Costs: Proved Plus Probable Reserves 0% (M$)
2020	231,031	261,291
2021	387,055	524,263
2022	360,363	592,773
2023	368,454	613,483
2024	407,868	646,721
Thereafter	351,989	908,734
Total Undiscounted	2,106,760	3,547,264
Change from 2018	135,756	102,233

Peyto anticipates that funding for the future development costs will include internally generated funds from operations, debt and equity financing.

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

2019 Finding, Development and Acquisition Costs
Company Interest Reserves
(Forecast Prices and Costs)

Finding, Development and Acquisition Costs Including Changes in Future Development Capital ("**FDC**")	Proved Developed Producing Reserves	Proved Reserves	Proved Plus Probable Reserves
Exploration and Development Capital Expenditures (M$)	205,374.8	205,374.8	205,374.8
Exploration and Development Change in FDC (M$)	-	135,756.0	102,233.0
Exploration and Development Capital including Change in FDC (M$)	205,374.8	341,130.8	307,607.8
Exploration and Development Reserve Additions including Revisions (Mboe)(1)	22,208.5	40,484.1	41,431.3
Finding and Development Cost ($/BOE)(1)	9.24	8.42	7.42
Net Acquisition Capital (M$)	1,055.8	1,055.8	1,055.8
Net Acquisition Reserve Additions (Mboe)(1)	-	-	-
Net Acquisition Cost ($/BOE)(1)	-	-	-
Total Capital Expenditures including Net Acquisitions (M$)	206,430.6	206,430.6	206,430.6
Total Changes in FDC (M$)	-	135,756.0	102,233.0
Total Capital including Change in FDC (M$)	206,430.6	342,186.6	308,663.6
Reserve Additions including Revisions and Net Acquisitions (Mboe)(1)	22,208.5	40,484.1	41,431.3
Finding, Development and Acquisition Cost including Change in FDC ($/BOE)(1)	9.29	8.45	7.45

Note:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of 6 Mcf of natural gas being equal to one barrel of oil.

Three Year Historical Finding, Development and Acquisition Costs
$/BOE

Year	Proved Developed Producing	Total Proved	Total Proved Plus Probable
2017	8.16	8.35	8.97
2018	7.05	7.25	6.10
2019	9.30	8.45	7.45
Three Year Average	8.17	8.02	7.51

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. The use of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of Peyto's principal oil and natural gas properties on production or under development as at December 31, 2019. The term "net", when used to describe Peyto's share of production, means the total of Peyto's working interest share before deduction of royalties owned by others. Reserve amounts are stated, before deduction of royalties, at December 31, 2019, based on escalating cost and price assumptions (gross) as evaluated in the InSite Report (see "*Statement of Reserves Data and Other Oil and Gas Information*"). Unless otherwise specified, gross and net acres and well count information are as at December 31, 2019. Information in respect of current production is average production, net to Peyto, for the month of February 2020, except where otherwise indicated. The estimate of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.

General

Peyto operates in three core areas, namely the Greater Sundance, Brazeau River areas and Northern area of Alberta. Within the Greater Sundance area there are four sub-areas, Sundance, Nosehill, Wildhay and Ansell, all of which have Peyto operated gas processing facilities that are interconnected. Total capital expenditures for 2019 were $206.4 million. In total, Peyto anticipates investing $250 to $300 million and plans to drill approximately 77 net wells with a focus on the Cardium liquids-rich resource play in 2020.

Greater Sundance Area

The Greater Sundance area is located 50 kilometers west of Edson, Alberta, from Township 50–56 and Range 19-24 west of the fifth meridian. Peyto began its operations in this area in the spring of 1999. This area now encompasses the Sundance, Wildhay, Nosehill and Ansell fields and is generally referred to as the "Greater Sundance area".

Peyto has an average 81% working interest in 346,240 gross (279,902 net) acres of land and operates 99% of its production in the area.

The geology of the area is characterized by multi-zone potential for liquids-rich natural gas. Peyto currently produces gas from the Belly River, Cardium, Viking, Notikewin, Falher, Wilrich, Bluesky, Cadomin and Montney formations.

During 2019, Peyto spent $193.6 million in capital to drill, case, complete, equip and tie-in 49 new net wells in the Greater Sundance area. Included in this capital is Peyto's proportionate share of land and seismic acquisition costs as well as plant costs. Peyto is currently producing approximately 69,580 boe/d. The Greater Sundance area includes several properties that collectively accounted for:

- 94% of 2019 capital expenditures
- 79% of 2019 production volume
- 78% of proved and probable reserves at December 31, 2019
- 41% of undeveloped land holding at December 31, 2019

Peyto currently plans to invest the majority of the 2020 capital budget drilling Cardium horizontal wells in this area.

Peyto owns and operates five 100% working interest gas processing plants and one joint plant (89% working interest at December 31, 2019) located in the Greater Sundance area. Two of the plants are located in Oldman (55-21W5), the third one is located in Wildhay (55-23W5), the fourth one is located in Nosehill (55-20W5) and the fifth and sixth plants are located in Ansell (53-20W5 and 53-19W5). The majority of Peyto's production is processed through these plants, with 1,425 gross (1,275 net) producing zones currently tied-in. Gross natural gas production at the facilities is approximately 353 MMcf/d, with gross natural gas liquids production being approximately 10,790 bbls/d.

Brazeau River

The Brazeau River area is located 180 km southwest of Edmonton, Alberta, from Township 41-44 and Range 11-14 west of the fifth meridian. Peyto began operations in this area in late 2013.

Peyto has an average 95% working interest in 124,480 gross (118,011 net) acres of land and operates 99% of its production in the area.

The geology of the area indicates multi-zone potential for liquids-rich natural gas. Peyto currently produces gas from the Notikewin, Belly River, Wilrich, Falher and Cardium formations.

In 2019, Peyto drilled 3 gross (3 net) wells in Brazeau. Peyto is currently producing approximately 11,840 boe/d, consisting of 63 MMcf/d gross natural gas and 1,290 bbls/d natural gas liquids from this area. The Brazeau area accounted for:

- 6% of 2019 capital expenditures
- 17% of 2019 production volume
- 14% of proved and probable reserves at December 31, 2019
- 9% of undeveloped land holding at December 31, 2019

Peyto owns a 100% working interest in and operates its gas processing plant in Brazeau. The majority of the production from the area is processed through this plant with 108 producing zones currently tied in. Gross production from this facility is approximately 63 MMcf/d of natural gas with approximately 1,290 bbls/d of natural gas liquids.

Northern Area

The Northern area includes producing properties in the following regions: Smoky, Kakwa, Chime, Kiskiu, Chicken and Cutbank and it encompasses Townships 57-64 and Ranges 2-7 west of the sixth meridian. The Kakwa gas plant, which services producing properties in Smoky, Kakwa, Chime and Kiskiu (together referred to as "**Greater Kakwa**") is located 40 km northeast of Grande Cache, Alberta. Peyto began operations in this area in the winter of 2002/2003.

Peyto has an average 91% working interest in 106,880 gross (97,631 net) acres of land and operates 97% of its production in the area.

The geology of the area indicates multi-zone potential for liquids-rich natural gas. Peyto currently produces gas from the Belly River, Dunvegan, Chinook and Cardium formations. The majority of Peyto's current production comes from the Cardium formation, which exists as a low permeability blanket sand.

Peyto is currently producing approximately 2,150 boe/d, consisting of 10 MMcf/d gross natural gas and 540 bbls/d natural gas liquids from this area. The Northern area accounted for:

- 0% of 2019 capital expenditures
- 3% of 2019 production volume
- 5% of proved and probable reserves at December 31, 2019
- 20% of undeveloped land holding at December 31, 2019

Peyto owns a 100% working interest in and operates its gas processing plant in Smoky/Kakwa. The majority of Peyto's production from the area is processed through this plant with 63 producing zones currently tied in. Gross production from this facility is approximately 8 MMcf/d of natural gas with approximately 505 bbls/d of natural gas liquids.

Peyto owns a 100% working interest in and operates its gas processing plant in Cutbank. The majority of the production around the Cutbank area is processed through this plant with 15 producing zones currently tied in. Gross production from this facility is approximately 1,000 Mcf/d of natural gas with approximately 21 bbls/d of natural gas liquids.

Miscellaneous

Peyto has a number of minor working interests in non-operated wells throughout Alberta. These properties account for less than 1% of Peyto's current production. The anticipated capital spending for these areas is minimal.

Oil and Gas Wells

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

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing(1)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	4.0	2.65	3.0	1.22	1,563.0	1,367.65	200.0	157.0
British Columbia	-	-	-	-	1.0	0.01	6.0	0.31
Total	4.0	2.65	3.0	1.22	1,564.0	1,367.66	206.0	157.31

Note:

(1) The non-producing oil wells and natural gas wells capable of production but which are not currently producing will be re-evaluated with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital.

Land Holdings

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

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	216,906	176,700	440,960	386,420	657,920	563,120
British Columbia	4,793	269	3,773	153	8,565	422
Total	221,753	176,969	444,733	386,573	666,485	563,542

Note:

(1) Numbers may not add due to rounding.

Peyto expects that rights to explore, develop and exploit 8,957 net acres (or 14 net sections) of its undeveloped land holdings will expire by December 31, 2020.

Hedging Contracts

Peyto is a party to certain derivative financial instruments, including fixed price contracts and physical delivery contracts. Peyto enters into these contracts with well established counter-parties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices.

A summary of contracts outstanding, as at December 31, 2019, in respect of the hedging activities is included in Note 15 to Peyto's audited financial statements for the year ended December 31, 2019, which are available on SEDAR at www.sedar.com.

Tax Horizon

No material cash income taxes were paid by Peyto for the year ended December 31, 2019. Within the context of current commodity prices and capital spending plans, Peyto does not expect to be taxable during the years ended December 31, 2020 or 2021. This future tax horizon will also fluctuate depending on the ultimate nature and timing of Peyto's acquisitions and dispositions. If crude oil and natural gas prices were to strengthen beyond the levels anticipated by the current forward market, Peyto's tax pools would be utilized more quickly and it may experience higher than expected cash taxes or payment of such taxes in an earlier time period. However, it is difficult to give guidance on future taxability as Peyto operates within an industry that constantly changes given acquisitions, divestments, capital spending, dividends and overall commodity prices. See "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

Peyto bases its estimates for the costs of abandonment and reclamation of surface leases, wells and facilities on previous experience of management with similar well sites and facility locations. As at December 31, 2019, management expected to incur such costs on 1,529 net wells and 9 net facilities. The total of such costs, net of estimated salvage value, expected to be incurred is $290 million (undiscounted) and $55 million (discounted at 5%). These estimated abandonment and reclamation costs do not include any locations for undrilled wells. Within the next three financial years, the Company does not expect to incur any abandonment or reclamation costs.

For the purposes of estimating the Reserves Data, abandonment and reclamation costs for all wells (both existing and undrilled wells) that have been attributed reserves, as well as those with no attributed reserves, have been taken into account.

Using public data and the Corporation's own experience, Peyto estimates the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment and reclamation cost history.

Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Peyto's audited financial statements for the year ended December 31, 2019 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to Peyto's activities for the year ended December 31, 2019.

Property acquisition (disposition) costs			
Proved properties	MM	$	1.0
Unproved properties			2.7
Exploration costs			4.6
Development costs			198.1
Total	MM	$	206.4

Exploration and Development Activities

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

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	-	-	-	-
Natural Gas	-	-	59	51
Service	-	-	-	-
Dry	-	-	2	2
Total:	-	-	61	53

For a description of Peyto's most important current and likely exploration and development activities, see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Oil and Gas Properties*".

Production Estimates

The following table sets out the volume of Peyto's production before royalties estimated for the year ended December 31, 2020 which is reflected in the estimate of gross proved reserves and probable reserves disclosed in the tables contained under "*Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data*".

	Light and Medium Crude Oil[1]	Conventional Natural Gas[2]	Natural Gas Liquids	BOE
	(bbls/d)	*(MMcf/d)*	*(bbls/d)*	*(boe/d)*
Proved				
Greater Sundance	6	344	10,013	67,411
Brazeau	-	70	1,308	12,959
Northern Area	-	8	496	1,868
Other	1	9	203	1,752
Total Proved 2020	6	432	12,020	83,990
Proved Plus Probable				
Greater Sundance	6	361	10,345	70,436
Brazeau	-	72	1,377	13,454
Northern Area	-	8	502	1,888
Other	1	9	269	1,835
Total Proved Plus Probable 2020	6	451	12,493	87,613

Notes:

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

Production History and Prices Received

The following table summarizes certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below.

	2019			
	Quarter Ended			
	Dec. 31	Sept. 30	June 30	March 31
Average Daily Production[1]				
Light and Medium Crude Oil (bbls/d)[2]	-	-	-	-
Conventional Natural Gas (Mcf/d)[3]	397,419	396,343	422,320	462,003
NGLs (bbls/d)	11,221	10,650	11,110	10,708
Combined (boe/d)	77,457	76,707	81,496	87,703
Average Price Received				
Light and Medium Crude Oil ($/bbl)[2]	-	-	-	-
Conventional Natural Gas ($/Mcf)[3]	1.96	1.84	1.83	2.48
NGLs ($/bbl)	43.85	39.65	44.70	50.37
Combined ($/McfGE)	2.76	2.50	2.60	3.20
Royalties Paid ($/McfGE)	0.12	0.03	0.01	0.14
Production Costs including Transportation ($/McfGE)	0.53	0.50	0.53	0.54
Netback Received ($/McfGE)	2.11	1.97	2.06	2.52

Notes:

(1) Before deduction of royalties.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas and by-products from oil wells.
(4) Unit values are based on net reserve volumes.
(5) Numbers may not add due to rounding.

The following table indicates Peyto's average daily production from its important fields, and in total, for the year ended December 31, 2019.

	Light and Medium Crude Oil[1]	Conventional Natural Gas[2]	NGLs	BOE
	(bbls/d)	(MMcf/d)	(bbls/d)	(boe/d)
Greater Sundance	6	330	8,888	63,826
Brazeau	-	74	1,302	13,557
Northern Area	5	9	514	2,005
Other Properties	1	7	206	1,414

	Light and Medium Crude Oil[1]	Conventional Natural Gas[2]	NGLs	BOE
	(bbls/d)	(MMcf/d)	(bbls/d)	(boe/d)
Total Alberta	12	419	10,910	80,802
Total British Columbia	-	-	-	-
Total	12	419	10,910	80,802

Notes:

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

DIVIDENDS

In conjunction with the completion of the 2010 Arrangement, the board of directors of the Corporation established a dividend policy of paying monthly dividends to the holders of Common Shares. The payment of dividends by the Corporation commenced with the first dividend declared to Shareholders of record on January 31, 2011 in the amount of $0.06 per Common Share, made payable February 15, 2011. It is expected that cash dividends will continue to be made by the Corporation on approximately the 15th day of each month to holders of Common Shares of record on the immediately preceding dividend record date.

Peyto's policy is to balance dividends to Shareholders with earnings and cash flow; and balance funding for the capital program with cash flow and available bank lines. The board of directors of the Corporation is prepared to adjust the payout ratio levels (dividends declared divided by funds from operations) to achieve the desired dividends while maintaining an appropriate capital structure. See "*Risk Factors – Dividends*".

The Corporation's credit facility and the terms of its outstanding senior unsecured notes ("**Senior Notes**") of the Corporation, including the 2015 Senior Notes, the 2016 Senior Notes, the 2018 Senior Notes and the 2019 Senior Notes and the other senior unsecured notes described in Note 5 to Peyto's audited financial statements for the year ended December 31, 2019, which are available on SEDAR at www.sedar.com, provide that if the Corporation is in default under the credit facility or the Senior Notes, as applicable, the indebtedness may be accelerated by the lenders, and the ability to pay dividends to Shareholders may be restricted. Dividends are only permitted under the credit facility and the terms of the Senior Notes when no event of default under the credit facility or the Senior Notes, as applicable, has occurred and is continuing.

Dividend History

Following the 2010 Arrangement, the following dividends were paid by the Corporation to Shareholders for the periods indicated:

For the Year Ended	Aggregate Annual Dividend per Common Share
2011	$0.72
2012	$0.72
2013	$0.88
2014	$1.14
2015	$1.32
2016	$1.32
2017	$1.32
2018	$0.72
2019	$0.24

On January 16, 2019, Peyto announced that, starting with the January 2019 dividend, the Corporation's monthly dividend would be temporarily reduced from $0.06 per Common Share to $0.02 per Common Share. See "*General Development of the Business – Three Year History – 2019*".

DESCRIPTION OF SHARE CAPITAL

Peyto is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per share at meetings of Shareholders, to receive dividends if, as and when declared by the board of directors of Peyto and to receive pro rata the remaining property and assets of Peyto upon its dissolution or winding-up, subject the rights of shares having priority over the Common Shares.

MARKET FOR SECURITIES

Common Shares

The Common Shares commenced trading on the TSX under the symbol "PEY" on January 7, 2011 following completion of the 2010 Arrangement. The following table sets forth the trading history of the Common Shares for the periods indicated as reported by the TSX.

	Price Range		
	High ($)	Low ($)	Volume
2020			
January	3.88	2.83	29,269,227
February	2.99	2.085	24,217,427
March (1 to 19)	2.32	0.91	34,911,057
2018			
January	8.035	6.49	28,407,506
February	8.00	6.62	13,608,512
March	7.90	6.94	14,657,373
April	7.22	6.03	17,035,416
May	6.07	4.70	16,573,598
June	4.79	3.78	19,982,407
July	4.46	3.63	28,204,054
August	3.98	2.98	30,445,988
September	4.34	3.065	36,187,956
October	3.38	2.57	31,649,743
November	3.25	2.66	35,322,944
December	3.93	2.62	33,856,050

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

DIRECTORS AND OFFICERS OF PEYTO

The name, municipality of residence, principal occupation for the current year and prior years of each of the current directors and officers of Peyto are set forth below.

Name and Municipality of Residence	Position with Peyto	Principal Occupation
Donald Gray Scottsdale, Arizona United States	Director since 1998 and Chairman of the Board since 2009	Private Investor; Chairman of Gear Energy Ltd., a public oil and natural gas company, since January 2010; Chairman of the Board of Petrus Resources Ltd., a public oil and gas company, since 2010; Mr. Gray was the President of EIQ Capital Corp., a private capital management company, from May 2007 to September 2017; prior thereto, Mr. Gray was the Chief Executive Officer of Peyto from August 2006 to January 2007; prior thereto, Mr. Gray was the President and Chief Executive Officer of Peyto from October 1998 to August 2006
Michael MacBean(1)(2)(3) Calgary, Alberta Canada	Director since 2003 and Lead Independent Director since 2009	Senior Managing Director of TriWest Capital Partners since May 12, 2010; prior thereto, Chief Executive Officer of Diamond Energy Services LP, an energy services partnership, since October 1998
Brian Davis(1)(2)(3) Houston, Texas United States	Director since 2006	Managing Partner of Oil and Gas Evaluations and Consulting, an independent oil and gas engineering consultancy firm based in Houston, Texas, since July 1994
Gregory Fletcher(1)(2)(3) Calgary, Alberta Canada	Director since 2007	President of Sierra Energy Inc., a private oil and gas production company, since 1997
John W. Rossall(2) Calgary, Alberta Canada	Director since 2019	Corporate director; prior thereto, Executive Director, North America of Repsol SA (formerly Talisman Energy Inc.) from May 2015 to July 2018; prior thereto, Senior Vice President, Canada of Repsol SA from September 2012 to May 2015; prior thereto, a strategic consulting advisor of Repsol SA from November 2011 to September 2012; prior thereto, President and Chief Executive Officer of ProspEx Resources Ltd., an oil and gas company listed on the TSX, and a member of its board of directors from August 2004 to May 2011
Darren Gee Calgary, Alberta Canada	President, Chief Executive Officer and Director since 2007	President and Chief Executive Officer of Peyto since January 2007 and President of Peyto since August 2006; prior thereto, Mr. Gee was the Vice President, Engineering of Peyto from March 2001 to August 2006
Kathy Turgeon Calgary, Alberta Canada	Vice President, Finance and Chief Financial Officer and Director since May 2018	Vice President, Finance and Chief Financial Officer since November 30, 2007; prior thereto Vice President, Finance of Peyto from January 2006 to November 2007; prior thereto, Ms. Turgeon was the Controller of Peyto from April 2004 to January 2006
Timothy Louie Calgary, Alberta Canada	Vice President, Land	Vice President, Land of Peyto since January 2012; prior thereto, Mr. Louie was Land Manager of Daylight Energy Ltd. from April 2005 to December 2011
Jean-Paul (JP) Lachance Calgary, Alberta Canada	Vice President, Engineering and Chief Operating Officer	Vice President, Engineering and Chief Operating Officer since February 1, 2018; prior thereto, Vice President, Exploitation of Peyto from September 2011 to February 1, 2018; prior thereto, Mr. Lachance was the Vice President, Engineering of ProspEx Resources Ltd. from October 2004 to May 2011
David Thomas Calgary, Alberta Canada	Vice President, Exploration	Vice President, Exploration of Peyto since November 1, 2010; prior thereto, Senior Geologist with Peyto since 2005

Name and Municipality of Residence	Position with Peyto	Principal Occupation
Lee Curran Calgary, Alberta Canada	Vice President, Drilling and Completions	Vice President, Drilling and Completions of Peyto since January 1, 2015; prior thereto, drilling engineer with Peyto since 2006; promoted to Drilling Manager with Peyto from May 2011 to January 2015
Todd Burdick Calgary, Alberta Canada	Vice President, Production	Vice President, Production of Peyto since January 1, 2015; prior thereto, production engineer with Peyto since 2004; promoted to Production Manager with Peyto from January 2010 to January 2015
Scott Robinson Calgary, Alberta Canada	Vice President, Business Development	Vice President, Business Development of Peyto since November 11, 2019; prior thereto, a consultant to Peyto from February 1, 2019 to November 10, 2019; prior thereto, Executive Vice President, New Ventures of Peyto from February 1, 2018 to February 1, 2019; prior thereto, Executive Vice-President and Chief Operating Officer of Peyto from August 2006 to February 1, 2018; prior thereto, Mr. Robinson was the Vice-President, Operations of Peyto from January 2004 to August 2006
Stephen J. Chetner Calgary, Alberta Canada	Corporate Secretary	Partner of Burnet, Duckworth & Palmer LLP

Notes:

(1) Member of the Audit Committee.
(2) Member of the Compensation and Nominating Committee.
(3) Member of the Reserves Committee.
(4) Peyto does not have an executive committee.
(5) Peyto directors shall hold office until the next annual general meeting of the Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.
(6) The period of time served as a director or officer of Peyto includes the period of time served as a director of Peyto AdminCo or an officer of PEDC, where and as applicable, prior to the completion of the 2010 Arrangement.

As at March 20, 2020, the directors and executive officers of Peyto, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 4.7 million Common Shares, or approximately 3% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed below, no director or officer of Peyto, or a shareholder holding a sufficient number of securities of Peyto to affect materially the control of Peyto is, as at the date hereof, or has been within the 10 years before the date hereof, a director, or executive officer of any company that: (i) while such person was acting in that capacity, 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 for a period of more than 30 consecutive days; (ii) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company any exemption under securities legislation, for a period of more than 30 consecutive days; or (iii) while such person was acting in that capacity or within a year of such 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.

Mr. Darren Gee, a director, President and Chief Executive Officer of Peyto, was a director of Endurance Energy Ltd. ("**Endurance**"), a corporation engaged in the exploration and production of natural gas. Mr. Gee resigned as a director of Endurance on September 1, 2015. Nine months after Mr. Gee's resignation, Endurance filed for creditor protection under the *Companies Creditors' Arrangement Act* on May 30, 2016.

No director or officer of Peyto, or a shareholder holding a sufficient number of securities of Peyto to affect materially the control of Peyto (or any personal holding company of such person), has been subject to 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 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.

Personal Bankruptcies

No director or officer of Peyto, or a shareholder holding sufficient securities of Peyto to affect materially the control of Peyto, or a personal holding company of any such persons, has, within the 10 years preceding the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became 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 individual.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Peyto will be subject in connection with the operations of Peyto. In particular, certain of the directors and officers of Peyto are involved in managerial or director positions with other oil and natural gas companies whose operations may, from time to time, be in direct competition with those of Peyto or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Peyto. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event 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 in the ABCA. As at the date hereof, Peyto is not aware of any existing material conflicts of interest between Peyto and any director or officer of Peyto.

Personnel

As at December 31, 2019, Peyto, directly or indirectly, employed 50 head office employees. Contract operators are retained for all field operations.

Audit Committee

Members

The Audit Committee currently has three members, Michael MacBean (Chairman), Brian Davis and Gregory Fletcher, none of whom have a direct or indirect material relationship with Peyto and each of whom is financially literate, meaning the individual has the ability to read and understand a set of financial statements that present a breadth and level of complexity of the issues that can be expected to be raised by Peyto's financial statements.

The following is a description of the education and experience of each member of the Audit Committee.

Michael MacBean

Mr. MacBean is the Chairman of the Audit Committee and the Corporation's independent lead director. Mr. MacBean is primarily engaged as a Senior Managing Director of TriWest Capital Partners and, prior thereto, was Chief Executive Officer of Diamond Energy Services LP, a partnership engaged in the energy services sector. Mr. MacBean is also a director of Source Energy Services Ltd., a public oilfield service company, and a director of TerraVest Industries Inc., a public industrial product manufacturing company. From 1995 through 1998, Mr. MacBean served as Controller and subsequently Senior Investment Analyst for ARC Financial Corporation. During this time Mr. MacBean also served as Vice President, Finance for ARC Energy Trust. Mr. MacBean received his Bachelor of Commerce Degree from the University of Saskatchewan in 1990. In 1993, Mr. MacBean received his Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. In February 2007, Mr. MacBean received his Chartered Directors (C.Dir) designation from McMaster University.

Brian Davis

Mr. Davis is the Chairman of the Reserves Committee. Mr. Davis is primarily engaged as the Managing Partner of Oil and Gas Evaluations and Consulting, an independent oil and gas engineering consultancy firm based in Houston, Texas, since July 1994. In his role, Mr. Davis has acquired significant experience and exposure to accounting and financial issues. Mr. Davis holds a BSc in petroleum engineering from Texas A&M University.

Gregory Fletcher

Mr. Fletcher is the Chairman of the Compensation & Nominating Committee. Mr. Fletcher is primarily engaged as the President of Sierra Energy Inc., a private oil and gas production company that he founded in 1997. Mr. Fletcher is also a director of Calfrac Well Services Ltd., a public oilfield service company, and a director of Whitecap Resources Inc., a public oil and gas company. In these roles, Mr. Fletcher has acquired significant experience and exposure to accounting and financial reporting issues. Mr. Fletcher holds a BSc in geology from the University of Calgary. In January 2009, Mr. Fletcher graduated from the Directors' Education Program sponsored by the Institute of Corporate Directors and the Haskayne School of Business.

Charter

The primary function of the Audit Committee is to assist the board of directors in fulfilling its oversight responsibilities for financial matters. It performs this function by serving as an independent and objective party to monitor Peyto's financial reporting process and internal control system; reviewing and assessing audit efforts of Peyto's independent auditors; providing an avenue of open communication among Peyto's independent auditors, financial and senior management and board of directors; and reviewing the independence and performance of the independent auditor. The Audit Committee has the authority to conduct or authorize investigations into any matters within the scope of its responsibilities and the authority to retain such outside counsel, experts and other advisors as it determines appropriate to assist in the conduct of any investigation. Attached as Schedule C hereto is the complete text of the Audit Committee's Charter.

Audit Fees

The table below provides disclosure of the fees billed to Peyto by its external auditors in fiscal 2019 and fiscal 2018, dividing the services into the categories of work performed.

Type of Work	2019 Fees	2019 Percentage	2018 Fees	2018 Percentage
Audit Fees	$200,000	74%	$200,000	66%
Audit Related Fees				
Review of interim financial statements and MD&A, reviewing prospectus disclosures	$54,000	20%	$54,000	18%
Insurance Advisory	-	-	$40,000	13%
Tax Fees				
Tax compliance services, tax advice, tax planning and annual filings	$16,000	6%	$10,000	3%
Total	$270,000		$304,000	

All non-audit services are disclosed and approved by the Audit Committee.

INDUSTRY CONDITIONS

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

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

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil, including global events such as the COVID-19 pandemic. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

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

Natural Gas Liquids

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

Exports from Canada

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

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

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

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

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

Transportation Constraints and Market Access

Pipelines

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

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

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

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

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

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

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

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

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

Crude Oil and Bitumen by Rail

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

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

Natural Gas

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

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a temporary policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system; however, the temporary policy change is expected to come to an end October 31, 2020. January 2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

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

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

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

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that

Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

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

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

Curtailment

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

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

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

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

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

The Corporation is not currently subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

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

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

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

Other Trade Agreements

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

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

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

Land Tenure

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

On March 20, 2020, the Government of Alberta announced that all Crown mineral agreements with an expiration date in 2020 will be extended for one year, in response to the economic stress on Alberta's oil and natural gas producers caused by the COVID-19 pandemic. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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

Each of the provinces of Alberta and British Columbia have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences. British Columbia has a policy of "zone specific retention" that that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

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

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

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

Royalties and Incentives

General

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

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

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

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

Alberta

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

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

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

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

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

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

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

British Columbia

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

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

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

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

Freehold and Other Types of Non-Crown Royalties

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

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

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

Regulatory Authorities and Environmental Regulation

General

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

Federal

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

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

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

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested. The Government of Alberta is challenging the constitutionality of Bill C-69, and has submitted a reference question to the Alberta Court of Appeal. The case is expected to be heard in the fall of 2020.

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

Alberta

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

On March 20, 2020, the Government of Alberta announced a $113 million contribution to the AER's industry levy, intended to provide financial relief in response to the economic stress and uncertainty facing Alberta's oil and natural gas industry as a result of the COVID-19 pandemic. See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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

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

The AER monitors seismic activity across Alberta, in the context of assessing the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing is an important and common practice to stimulate production of oil and gas from dense subsurface rock formations. The process 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 gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

In an ongoing process spanning between February 19, 2015 to December 9, 2019, 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 that are aimed at limiting the impact and potential of induced earthquakes from hydraulic fracturing are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). The Corporation does have operations in Brazeau. 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. The 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 oil or natural gas producers' operations while it conducts investigations following a seismic event, and only when the AER has assessed ongoing risk of earthquakes in a specific area and/or required the oil or natural gas producer to update its response plan, can operations resume. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of the AER's ongoing province-wide monitoring.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**BC Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and*

Management Regulation establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Beginning in 2015, the British Columbia Government has introduced a regime to monitor and manage the risk of seismicity induced by the oil and natural gas industry, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation*, as amended in June 2015 requires and oil and gas producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). The BC Commission monitors Natural Resources Canada's reporting of seismicity across the province, and has installed additional seismograph stations in northeast British Columbia. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

The British Columbia Government passed *Bill 51 – 2018: Environmental Assessment Act in* late 2018, which will replace the environmental assessment regime that has been in place since 2002. The updated *Environmental Assessment Act* came into force on December 16, 2019. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process. The new environmental assessment process aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building, in alignment with British Columbia's recent passage of Bill 41, which affirmed and adopted the United Nations Declaration on the Rights of Indigenous Peoples. Simultaneously with the enactment of the *Environmental Assessment Act*, the British Columbia Government enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project. However, many details of the new assessment process remain unknown, but the British Columbia Government has released a proposed timetable for the release of supplementary and informational materials through 2020.

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

Liability Management Rating Program

Alberta

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

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

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

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

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

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

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

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

British Columbia

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

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

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

Climate Change Regulation

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

Federal

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

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019.

This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

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

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

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

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

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

Alberta

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

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

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

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

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

British Columbia

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

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

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

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

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

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

Public Health Crises

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

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

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

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

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

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

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

Weakness and Volatility in the Oil and Natural Gas Industry

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

Market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, conflict between the United States and Iran, isolationist and punitive trade policies, increased United States shale production, sovereign debt levels, world health emergencies (including the COVID-19 pandemic) and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant weakness and volatility in commodity prices. Through the first few months of 2020, oil prices deteriorated due to softening global demand caused by the COVID-19 pandemic. In March 2020, OPEC and Russia were unable to reach an agreement to further reduce oil production in response to the COVID-19 pandemic. Saudi Arabia responded by reducing its pricing and promising to increase production to over 10 million bbl/day. These actions led to the deepest drop in crude oil prices that global markets have seen since 1991. With the rapid spread of COVID-19 and additional oil supply expected to come on-stream over the near term, oil prices and global equity markets have deteriorated significantly and are expected to remain under pressure. The extreme supply / demand imbalance is anticipated to cause a reduction in industry spending in 2020. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Industry Conditions – Royalties and Incentives", "Industry Conditions – Regulatory Authorities and Environmental Regulation*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*– Political Uncertainty*" and the other risk factors herein. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

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

Prices, Markets and Marketing

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

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

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

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

See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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

Market Price

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

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

Exploration, Development and Production Risks

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

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

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

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

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

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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

Depending on the market conditions for such non-core assets, certain non-core assets of Peyto may realize less on disposition than their carrying value on the financial statements of Peyto.

Political Uncertainty

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

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA. As of March 13, 2020, each of Canada, the United States and Mexico have ratified the USMCA and it will come into force on June 1, 2020. Until then, NAFTA will continue to govern trade relations among Canada, Mexico, and the United States. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation. See "*Industry Conditions – The North American Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including Peyto.

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

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. In January 2020, the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia; however,, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction where Peyto is active. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

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

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 Peyto's activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas*".

Operational Dependence

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

Other companies operate approximately 2% of the assets in which Peyto has an interest. Peyto has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect Peyto's financial performance. Peyto's return on assets operated by others depends upon a number of factors that may be outside of Peyto's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

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

Project Risks

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

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

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or Peyto's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Gathering and Processing Facilities, Pipeline Systems and Rail

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

Peyto delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that Peyto can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in Peyto's inability to realize the full economic potential of its products or in a reduction of the price offered for Peyto's production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect Peyto's production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

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

Competition

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

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

Information Technology Systems and Cyber-Security

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

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

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

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

Cost of New Technologies

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

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

Alternatives to and Changing Demand for Petroleum Products

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

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

Regulatory

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

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

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

Royalty Regimes

Changes to royalty regimes may negatively impact Peyto's cash flows

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

Hydraulic Fracturing

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

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

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau and Red Deer. Since 2015, the AER has introduced seismic protocols for hydraulic fracturing operators in the Seismic Protocol Regions—initially in response to significant induced seismic activity in the Duvernay formation in Fox Creek in February 2015. 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 which vary among the three regions. The reporting requirements include an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events and the suspension of operations, depending on the magnitude of an earthquake. Orders imposed by the AER in response to seismic events remain in effect as long as the AER deems them necessary.

Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

In March 2018 and March 2019, two earthquakes felt in Red Deer and Sylvan Lake were characterized as seismic activity induced by hydraulic fracturing. In March 2019, the AER suspended operations of an oil and natural gas company in the area where the earthquake occurred, pending further investigation. In May 2019, the suspended oil and natural gas company was able to resume operations with a risk assessment plan in place that was approved by the AER.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta*".

British Columbia

Due to seismic activity recorded in the Kiskatinaw Area, in May 2018, the BC Commission issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw Area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BC Commission and the suspension of operations if a seismic event above a 3.0 magnitude occurs. On November 29, 2018, hydraulic fracturing operations of a natural gas producer in the Montney area in British Columbia were suspended after a series of three seismic events, ranging from 3.4 to 4.5 in magnitude, were linked to hydraulic fracturing by the BC Commission. Though the BC Commission allowed the natural gas producer to resume operations in the Montney area on October 21, 2019, this suspension demonstrates the BC Commission's willingness to enforce its enhanced regulatory requirements. The same natural gas producer was also suspended from using a wastewater disposal well in 2019 due to seismicity attributed to the use of that well, demonstrating that the BC Commission's monitoring and oversight of seismic risk is not limited to hydraulic fracturing.

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. The panel's recommendations included directing the Government of British Columbia to consider classifying hydraulic fracturing wastewater as hazardous waste, certain best practices for producers conducting hydraulic fracturing and increased water and seismicity monitoring by the BC Commission in northeastern British Columbia. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect Peyto's business operation, financial condition, results of operations and prospects.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. Under the *Water Sustainability Act*, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the *Dam Safety Regulation*. Larger dams are also subject to an environmental assessment and approval under the *Environmental Assessment Act*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. While the BC Commission has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent the relevant industry regulators will respond to this issue. Peyto may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where Peyto is not strictly complying with the current regulatory framework.

Environmental

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

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

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

Liability Management

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

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 is unable to satisfy its regulatory obligations. Changes to the AB LMR Program administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to Peyto's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program may prevent or interfere with Peyto's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

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

Chronic Climate Change Risks

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

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

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the

Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

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

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict Peyto's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of Peyto's assets are located in locations that are proximate to forests and rivers and a wildfire and/or flood may lead to downtime, restrictions on access and/or damage to such assets. Given the cleared setbacks surrounding the Corporation's assets, there is minimal risk to such assets in the event of a wildfire. Additionally, Peyto is set up to operate its wells remotely using SCADA and also has access to business interruption insurance in the event that such extreme conditions have a prolonged disruption on its operations. Extreme weather conditions could also lead to disruptions in Peyto's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

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

Substantial Capital Requirements

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

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

- the overall state of the capital markets;
- Peyto's credit rating (if applicable);
- commodity prices;

- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and Peyto's securities in particular.

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

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

Additional Funding Requirements

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

Peyto's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties. See "*– Weakness in the Oil and Natural Gas Industry*".

Credit Facility Arrangements

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

Peyto currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may include certain financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond Peyto's control may contribute to the failure of Peyto to comply with such covenants. In light of the current volatility in commodity prices, Peyto will be routinely monitoring its financial forecasts, capital spending, balance sheet and dividend policy and has the ability to make operational and financial changes to help ensure Peyto remains compliant with all financial covenants. If necessary, Peyto can request temporary relief from financial covenants from lenders. In the event Peyto does not comply with it's financial covenants and lenders do not grant covenant relief, Peyto's access to capital could be restricted or repayment required. Even if Peyto is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to Peyto. If Peyto is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of Peyto's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, Peyto's credit facility may impose operating and financial restrictions on Peyto that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to Peyto's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices have recently increased they remain volatile as a result of various factors including limited egress options for Western Canadian oil and natural gas producers, actions taken to limit OPEC and non-OPEC production and increasing production by U.S. shale producers. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

The Supreme Court of Canada's decision in Redwater may give rise to new covenants and restrictions under Peyto's credit facilities, should LMR levels fall below existing agreed-upon thresholds, including further limitations on asset dispositions and acquisitions. Peyto may also be required to provide additional reporting to its lenders regarding its existing and/or budgeted abandonment and reclamation obligations, its decommissioning expenses, its LMR and/or any notices or orders received from an energy regulator in any applicable province. See also "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

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

Issuance of Debt

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

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

Hedging

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

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

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;

- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time Peyto may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, Peyto will not benefit from the fluctuating exchange rate. The Corporation hedges its risk management activities in accordance with the hedging policy approved by the board of directors of Peyto.

Availability and Cost of Material and Equipment

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

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

Title to and Right to Produce from Assets

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

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

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

Reserves Estimates

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

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

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

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

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

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

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

Insurance

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

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

Non-Governmental Organizations

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

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

Dilution

Peyto may issue additional Common Shares, diluting current Shareholders

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

Management of Growth

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

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

Expiration of Licences and Leases

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

Peyto's properties are held in the form of licences and leases and working interests in licences and leases. If Peyto 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 Peyto's licences or leases or the working interests relating to a licence or lease and the associated abandonment and reclamation obligations may have a material adverse effect on Peyto's business, financial condition, results of operations and prospects.

Dividends

The amount of and frequency at which future cash dividends are paid may vary and there is no assurance that Peyto will pay dividends in the future

The amount of future cash dividends paid by Peyto, if any, will be subject to the discretion of the board of directors of the Corporation and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of Peyto, the dividend policy of Peyto from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by Peyto and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by Peyto to finance capital expenditures using funds from operations.

To the extent that external sources of capital, including in exchange for the issuance of additional Common Shares, become limited or unavailable, the ability of Peyto to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that Peyto is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Litigation

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

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

Indigenous Claims

Indigenous claims may affect Peyto

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

Breach of Confidentiality

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

While discussing potential business relationships or other transactions with third parties, Peyto may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put Peyto at competitive risk and may cause significant damage to its business. The harm to Peyto'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, Peyto will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

Taxation authorities may reassess Peyto's tax returns

Peyto 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 Peyto, 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 Peyto. Furthermore, tax authorities having jurisdiction over Peyto may disagree with how Peyto calculates its income for tax purposes or could change administrative practices to Peyto's detriment.

Seasonality

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

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

Third Party Credit Risk

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

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

Conflicts of Interest

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

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

Reliance on a Skilled Workforce and Key Personnel

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

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

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

Expansion into New Activities

Expanding Peyto's business exposes it to new risks and uncertainties

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

Forward-Looking Information

Forward-Looking Information May Prove Inaccurate

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

Additional information on the risks, assumption and uncertainties are found under the heading "*Notice to Reader*" in this Annual Information Form.

Waterflood

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

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

Disposal of Fluids Used in Operations

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

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

Carbon Pricing Risk

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

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

Reputational Risk Associated with Peyto's Operations

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

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

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

Changing Investor Sentiment

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

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the financial year ended December 31, 2019, Peyto was not a party to any legal proceeding, nor was it a party to, nor is or was any of its property the subject of any legal proceeding, involving claims for damages where the amount involved, exclusive of interest and costs, is in excess of ten percent (10%) of the current assets of Peyto, nor are there any such proceedings known to be contemplated.

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of Peyto, any securityholder who directly or indirectly beneficially owns, or exercises control or direction over, more than 10% of the outstanding voting securities of Peyto or any known associate or affiliate of such persons in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or will materially affect Peyto.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Deloitte LLP, Chartered Professional Accountants, the auditor of Peyto, is independent within the meaning of the Rules of Professional Conduct of the applicable Chartered Professional Accountants provincial regulator of Alberta.

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, Peyto has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement, report or valuation made by such person or company and who is named as having prepared or certified a report, valuation statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 – *Continuous Disclosure Obligations* by Peyto during, or related to, Peyto's most recently completed financial year other than InSite, Peyto's independent engineering evaluators, and Deloitte LLP, Chartered Professional Accountants, the auditor of Peyto. To the knowledge of Peyto, none of the designated professionals of InSite had any registered or beneficial interests, direct or indirect, in any securities or other property of Peyto or of Peyto's associates or affiliates either at the time they prepared the statement, report or valuation prepared by them, at any time thereafter or to be received by them. Deloitte LLP, Chartered Professional Accountants, is independent within the meaning of the Rules of Professional Conduct of the applicable Chartered Professional Accountants provincial regulator of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Peyto or of any associate or affiliate of Peyto, except for Stephen J. Chetner, the Corporate Secretary of Peyto, who is a partner of Burnet, Duckworth & Palmer LLP, which law firm renders legal services to Peyto.

ADDITIONAL INFORMATION

Additional information relating to Peyto may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Peyto's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the information circular of Peyto for its most recent annual meeting of securityholders that involved the election of directors. Additional financial information is contained in Peyto's audited consolidated financial statements and related management's discussion and analysis for the year ended December 31, 2019.

SCHEDULE A – FORM 51-101F3
REPORT ON MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

Management of Peyto is responsible for the preparation and disclosure of information with respect to the oil and gas activities of Peyto in accordance with securities regulatory requirements. This information includes reserves data.

An independent qualified reserves evaluator has evaluated Peyto's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of Peyto, on behalf of Peyto, has

(a) reviewed Peyto'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 of Peyto has reviewed Peyto'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 Reserve Committee, approved

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

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

(c) the content and filing of this report.

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

(signed) "*Darren Gee*"
Darren Gee
President and Chief Executive Officer

(signed) "*Jean-Paul Lachance*"
Jean-Paul Lachance
Vice President, Engineering and Chief Operating Officer

(signed) "*Brian Davis*"
Brian Davis
Director and Chairman of the Reserves Committee

(signed) "*Michael MacBean*"
Michael MacBean
Director and Member of the Reserves Committee

April 6, 2020

SCHEDULE B – FORM 51-101F2
REPORT ON RESERVES DATA

To the Board of Directors of Peyto Exploration & Development Corp. (the "**Company**"):

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

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

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

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

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

			Net Present Value of Future Net Revenue ($ thousands CDN - before income taxes, 10% discount rate)[1]			
Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
InSite Petroleum Consultants Ltd.	Evaluation of Oil & Gas Properties of Peyto Exploration & Development Corp. as at December 31, 2019 (Amended), prepared April 6, 2020	Canada	-	4,125,263.4	-	4,125,263.4

6. Contingent and prospective resources were not evaluated in this report as per the request of the Company.

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

8. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after its preparation date.

9. 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:

INSITE PETROLEUM CONSULTANTS LTD.
Calgary, Alberta, Canada

Execution Date: April 6, 2020

(signed) "*Peter P. Hadala*"
Peter P. Hadala, P.Eng.
President & Managing Director

[1] This amount must be the amount disclosed by the *reporting issuer* in its statement of *reserves data* filed under item 1 of section 2.1 of *NI 51-101*, as its *future net revenue* (before deducting *future income tax expenses*), attributable to *proved* plus *probable reserves*, estimated using *forecast prices and costs* and calculated using a discount rate of 10 percent (required by section 2 of item 2.1 of *Form 51-101F1*). The values represented are shown in Canadian dollars.

SCHEDULE C – AUDIT COMMITTEE CHARTER

PEYTO EXPLORATION & DEVELOPMENT CORP.

AUDIT COMMITTEE

AUDIT COMMITTEE CHARTER

This charter governs the operations of the audit committee (the "**Committee**") of Peyto Exploration & Development Corp. ("**Peyto**"). The Committee shall report to the board of directors (the "**Board**") of Peyto.

I. PURPOSE

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

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

(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 Peyto.

The Committee will review and discuss:

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

(ii) any significant proposed changes in financial reporting and accounting policies and practices to be adopted by Peyto:

(iii) any new or pending developments in accounting and reporting standards that may affect Peyto;

(iv) ascertain compliance with the covenants under loan agreements;

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

(vi) 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 Peyto'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 Peyto'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 Peyto'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;
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 Peyto regarding accounting, internal controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters.

IV. ACCOUNTABILITY

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

V. STANDARDS OF LIABILITY

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