BIRCHCLIFF ENERGY

**BIRCHCLIFF ENERGY LTD.**

**Year Ended December 31, 2019**

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# ANNUAL INFORMATION FORM

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**March 11, 2020**

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## GLOSSARY OF TERMS

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"**2018 Resource Assessment**" has the meaning set forth in Appendix A.

"**2019 Regulations**" has the meaning set forth under the heading *"Industry Conditions – Land Tenure".*

"**2019 Resource Assessment**" has the meaning set forth in Appendix A.

"**2026 Agreement**" has the meaning set forth under the heading *"Description of the Business – Marketing and Risk Management – Light Oil and NGLs".*

"**ABCA**" means the *Business Corporations Act* (Alberta).

"**ABC Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AB LFP Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AB LLR Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AB LMR Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AB OWL Program**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**AER**" means the Alberta Energy Regulator.

"**Alberta Methane Regulations**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**AltaGas**" means AltaGas Ltd.

"**Annual Information Form**" means this annual information form of the Corporation dated March 11, 2020 for the year ended December 31, 2019.

"**Bill C-48**" means Bill C-48: *An Act respecting the regulation of vessels that transport crude oil or persistent oil to or from ports or marine installations located along British Columbia's north coast.*

"**Bill C-69**" means Bill C-69: *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts.*

"**Birchcliff**" or the "**Corporation**" means Birchcliff Energy Ltd.

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

"**Cabinet**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada".*

"**CCEMA**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**CCIR**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**CDE**" means Canadian development expenses.

"**CEAA**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal".*

"**CEA Agency**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal".*

"**CER**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada".*

"**CERA**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada".*

"**CETA**" has the meaning set forth under the heading *"Industry Conditions – NAFTA and Other Trade Agreements – Other Trade Agreements".*

"**CGL**" has the meaning set forth under the heading *"Industry Conditions – Transportation Constraints and Market Access – Natural Gas".*

"**CGL Pipeline**" has the meaning set forth under the heading *"Industry Conditions – Transportation Constraints and Market Access – Natural Gas".*

"**Charlie Lake Light Oil Resource Play**" has the meaning set forth under the heading *"General Development of the Business – Three Year History – 2017".*

"**CLA**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**CLP**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

"**COGPE**" means Canadian crude oil and natural gas property expenses.

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

"**condensate**" means pentanes plus (C5+).

"**Consolidated Reserves Report**" has the meaning set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data"*.

"**COR**" means a certificate of recognition.

"**COVID-19**" means the novel coronavirus.

"**CPTPP**" has the meaning set forth under the heading *"Industry Conditions – NAFTA and Other Trade Agreements – Other Trade Agreements".*

"**CRA**" means the Canada Revenue Agency.

"**Credit Facilities**" has the meaning set forth under the heading *"Description of Capital Structure – Credit Facilities"*.

"**CSA Staff Notice 51-324**" means the Canadian Securities Administrators' Staff Notice 51-324 – *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*.

"**Current Market Price**" has the meaning set forth under the heading *"Description of Capital Structure – Authorized Share Capital and Securities Outstanding – Preferred Shares – Series C Preferred Shares"*.

"**Deloitte**" means Deloitte LLP, independent qualified reserves evaluators of Calgary, Alberta.

"**Deloitte Reserves Report**" has the meaning set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data"*.

"**EAO**" has the meaning set forth under the heading *"Industry Conditions – Transportation Constraints and Market Access – Natural Gas".*

"**EM Program**" has the meaning set forth under the heading *"Description of the Business – Environmental, Social and Governance – Health, Safety and Environmental Programs".*

"**ESG**" means environmental, social and governance.

"**ESTMA**" means the *Extractive Sector Transparency Measures Act* (Canada).

"**Federal Government**" means the federal Government of Canada.

"**Federal Methane Regulations**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Federal".*

"**GAAP**" means generally accepted accounting principles for Canadian public companies which are currently IFRS.

"**GGPPA**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Federal".*

"**GHG**" means greenhouse gas.

"**Gordondale Gas Plant**" means the deep-cut sour gas processing facility in Gordondale which is owned and operated by AltaGas.

"**Gordondale Processing Arrangement**" has the meaning set forth under the heading *"General Development of the Business – Three Year History – 2018".*

"**H&S Program**" has the meaning set forth under the heading *"Description of the Business – Environmental, Social and Governance – Health, Safety and Environmental Programs".*

"**IAA**" has the meaning set forth under the heading *"Industry Conditions – Transportation Constraints and Market Access – Pipelines".*

"**IA Agency**" has the meaning set forth under the heading *"Industry Conditions – Transportation Constraints and Market Access – Natural Gas".*

"**IFRS**" means International Financial Reporting Standards as issued by the International Accounting Standards Board.

"**Inlet Liquids-Handling Facility**" has the meaning set forth under the heading *"General Development of the Business – Recent Developments".*

"**IOGA**" has the meaning set forth under the heading *"Industry Conditions – Land Tenure".*

"**IOGC**" has the meaning set forth under the heading *"Industry Conditions – Land Tenure".*

"**IQRE Price Forecast**" has the meaning set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data".*

"**IWCP**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**LMR**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**McDaniel**" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators of Calgary, Alberta.

"**McDaniel Reserves Report**" has the meaning set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data"*.

"**Modernized Framework**" has the meaning set forth under the heading *"Industry Conditions – Royalties and Incentives – The Royalty Framework in Alberta – Crown Royalties"*.

"**Modernized IOGA**" has the meaning set forth under the heading *"Industry Conditions – Land Tenure".*

"**Montney/Doig Resource Play**" means Birchcliff's Montney and Doig formations resource play located northwest of Grande Prairie, Alberta.

"**NAFTA**" means the North American Free Trade Agreement between the Governments of Canada, the United States and Mexico.

"**NEB**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada"*.

"**NEB Act**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada"*.

"**NGTL System**" means the pipeline system owned by Nova Gas Transmission Ltd., a subsidiary of TCPL.

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

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

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

"**NIT**" means Alberta Nova Inventory Transfer.

"**OGCA**" means the *Oil and Gas Conservation Act* (Alberta).

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

"**Options**" means stock options to purchase Common Shares.

"**Order**" has the meaning set forth under the heading "*Directors and Officers – Cease Trade Orders, Bankruptcies, Penalties or Sanctions".*

"**Orphan Fund**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**Pan-Canadian Framework**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Federal".*

"**Part VI Regulation**" has the meaning set forth under the heading *"Industry Conditions – Exports from Canada".*

"**Pembina Facility**" has the meaning set forth under the heading *"Description of the Business – Principal Properties – The Montney/Doig Resource Play – Key Operating Areas – Gordondale"*.

"**Performance Warrants**" means the performance warrants of the Corporation which expire on January 31, 2025, with each performance warrant providing the right to purchase one Common Share at a price of $3.00 per Common Share.

"**Pouce Coupe Acquisition**" means the acquisition by the Corporation of certain petroleum and natural gas properties, interests and related assets located in the Pouce Coupe area pursuant to a purchase and sale agreement dated November 2, 2018, which acquisition closed on January 3, 2019.

"**Pouce Coupe Gas Plant**" means Birchcliff's 100% owned and operated natural gas processing plant located in the Pouce Coupe area of Alberta.

"**Preferred Shares**" means the preferred shares of the Corporation as a class.

"**Previous Framework**" has the meaning set forth under the heading *"Industry Conditions – Royalties and Incentives – The Royalty Framework in Alberta – Crown Royalties".*

"**Prior Consolidated Reserves Report**" means the consolidated reserves report prepared by Deloitte with an effective date of December 31, 2018.

"**Progress Disposition**" means the disposition by the Corporation of certain petroleum and natural gas properties, interests and related assets primarily located in the Progress area on the Charlie Lake Light Oil Resource Play pursuant to a purchase and sale agreement dated August 10, 2017, which disposition closed on October 2, 2017.

"**Redwater**" has the meaning set forth under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Alberta – Liability Management Rating Program"*.

"**Revised 2020 Capital Program**" has the meaning set forth under the heading *"General Development of the Business – Recent Developments".*

"**SEDAR**" means the System for Electronic Document Analysis and Retrieval.

"**Series A Preferred Shares**" means the cumulative redeemable preferred shares, Series A of the Corporation which were issued on August 8, 2012.

"**Series B Preferred Shares**" means the cumulative redeemable preferred shares, Series B of the Corporation which are issuable on the conversion of the Series A Preferred Shares.

"**Series C Preferred Shares**" means the cumulative redeemable preferred shares, Series C of the Corporation which were issued on June 14, 2013.

"**Stock Option Plan**" means the Corporation's stock option plan, as amended and restated on December 13, 2018.

"**Syndicated Credit Facility**" has the meaning set forth under the heading *"Description of Capital Structure – Credit Facilities*".

"**TCC Decision**" has the meaning set forth under the heading *"Legal Proceedings and Regulatory Actions"*.

"**TC Energy**" means TC Energy Corporation.

"**TCPL**" means TransCanada PipeLines Limited, a subsidiary of TC Energy.

"**TIER**" and "**TIER Regulation**" have the meanings set forth under the heading *"Industry Conditions – Climate Change Regulation – Alberta".*

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

"**UNFCCC**" has the meaning set forth under the heading *"Industry Conditions – Climate Change Regulation – Federal"*.

"**USMCA**" has the meaning set forth under the heading *"Industry Conditions – NAFTA and Other Trade Agreements – NAFTA and USMCA".*

"**Veracel**" means Veracel Inc.

"**Working Capital Facility**" has the meaning set forth under the heading *"Description of Capital Structure – Credit Facilities*".

"**Worsley Disposition**" means the disposition by the Corporation of certain petroleum and natural gas properties, interests and related assets primarily located in the Worsley area on the Charlie Lake Light Oil Resource Play pursuant to a purchase and sale agreement dated August 1, 2017, which disposition closed on August 31, 2017.

## ABBREVIATIONS AND CONVERSIONS

### Abbreviations

The abbreviations set forth below have the following meanings:

**Oil and Natural Gas Liquids**

| | |
|---|---|
| bbl | barrel |
| bbls | barrels |
| bbls/d | barrels per day |
| C3+ | propane plus |
| Mbbls | thousand barrels |
| MMbbls | million barrels |
| MMbbls/d | million barrels per day |
| NGLs | natural gas liquids |

**Natural Gas**

| | |
|---|---|
| Bcf | billion cubic feet |
| GJ | gigajoule |
| GJ/d | gigajoules per day |
| LNG | liquefied natural gas |
| Mcf | thousand cubic feet |
| Mcf/d | thousand cubic feet per day |
| MMBtu | million British thermal units |
| MMcf | million cubic feet |
| MMcf/d | million cubic feet per day |

**Other**

| | |
|---|---|
| AECO | benchmark price for natural gas determined at the AECO 'C' hub in southeast Alberta |
| Bcfe | billion cubic feet of gas equivalent |
| boe | barrel of oil equivalent |
| boe/d | barrel of oil equivalent per day |
| $CO_2e$ | carbon dioxide equivalent |
| km | kilometres |
| $m^3$ | cubic metres |
| Mboe | thousand barrels of oil equivalent |
| Mcfe | thousand cubic feet of gas equivalent |
| MM$ | millions of dollars |
| NPV | net present value of future net revenue |
| NYMEX | New York Mercantile Exchange |
| PIIP | petroleum initially-in-place |
| WTI | West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma, for crude oil of standard grade |

### Conversions

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

| From | To | Multiply By |
|---|---|---|
| Mcf | cubic metres | 28.317 |
| cubic metres | cubic feet | 35.315 |
| 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 |

## CONVENTIONS

Certain terms used herein are defined in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook, as the case may be.

Unless otherwise indicated, all information contained herein is given at or for the year ended December 31, 2019. Unless otherwise indicated, all dollar amounts are expressed in Canadian dollars and all references to "$", "CDN$" or "dollars" are to Canadian dollars and all references to "US$" are to United States dollars. Except where otherwise indicated, all financial information contained in this Annual Information Form has been presented in accordance with GAAP. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

## NON-GAAP MEASURES

This Annual Information Form uses "netback" and "transportation and other costs" which do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. "Netback" is calculated by subtracting royalties, production costs and transportation and other costs from the average price received. Management believes that netback assists management and investors in assessing Birchcliff's operating results by isolating the impact of production volumes to better analyze its performance against prior periods on a comparable basis. "Transportation and other costs" denotes transportation expense plus marketing purchases minus marketing revenue. Birchcliff may enter into certain marketing purchase and sales arrangements with the objective of reducing any available transportation and/or fractionation fees associated with its take-or-pay commitments. Management believes that transportation and other costs assist management and investors in assessing Birchcliff's total cost structure related to transportation activities. For additional information regarding netbacks and transportation and other costs, please see *"Non-GAAP Measures"* in management's discussion and analysis for the year ended December 31, 2019.

## PRESENTATION OF OIL AND GAS RESERVES AND RESOURCES

Deloitte prepared the Consolidated Reserves Report, the Deloitte Reserves Report, the Prior Consolidated Reserves Report, the 2019 Resource Assessment and the 2018 Resource Assessment. McDaniel prepared the McDaniel Reserves Report. Such evaluations were prepared in accordance with the standards contained in NI 51-101 and the COGE Handbook that were in effect at the relevant time.

With respect to any disclosure of reserves contained herein relating to portions of Birchcliff's properties, the estimates 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. Estimates of future net revenue, whether calculated without discount or using a discount rate, do not represent fair market value.

With respect to the discovered resources (including contingent resources) disclosed in this Annual Information Form, there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the undiscovered resources (including prospective resources) disclosed in this Annual Information Form, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

Unless otherwise indicated, all volumes of Birchcliff's reserves and resources presented herein are on a gross basis and all volumes of Birchcliff's resources presented herein are on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality.

### Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

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

- "**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.
- "**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.
- "**Possible reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

**Levels of Certainty for Reported Reserves**

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves 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 estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are 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.

**Development and Production Status of Reserves**

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

- "**Developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
    - "**Developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
    - "**Developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production but are shut-in and the date of resumption of production is unknown.
- "**Undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.

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

**Resources and Production**

Resources encompass all petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Resources are classified as follows:

- Total PIIP is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. "Total resources" is equivalent to "total PIIP".

- Discovered PIIP is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered PIIP includes production, reserves and contingent resources; the remainder is unrecoverable.

- Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies.

- Undiscovered PIIP is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered PIIP is referred to as prospective resources; the remainder is unrecoverable.

- Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

- Unrecoverable is that portion of discovered and undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

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

**Uncertainty Ranges for Resources**

Estimates of resource volumes can be categorized according to the range of uncertainty associated with the estimates. Uncertainty ranges are described in the COGE Handbook as low, best and high estimates as follows:

- A "low estimate" (1C) is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

- A "best estimate" (2C) is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

- A "high estimate" (3C) is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

**Interest in Reserves, Resources, Production, Wells and Properties**

"**Gross**" means: (a) in relation to Birchcliff's interest in production, reserves or resources, Birchcliff's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Birchcliff; (b) in relation to wells, the total number of wells in which Birchcliff has an interest; and (c) in relation to properties, the total area of properties in which Birchcliff has an interest.

"**Net**" means: (a) in relation to Birchcliff's interest in production, reserves or resources, Birchcliff's working interest (operating or non-operating) share after deduction of royalty obligations, plus Birchcliff's royalty interests in production or reserves; (b) in relation to Birchcliff's interest in wells, the number of wells obtained by aggregating

Birchcliff's working interest in each of its gross wells; and (c) in relation to Birchcliff's interest in a property, the total area in which Birchcliff has an interest multiplied by the working interest owned by Birchcliff.

**Forecast Prices and Costs**

"**Forecast prices and costs**" mean future prices and costs that are: (a) generally accepted as being a reasonable outlook of the future; (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Birchcliff 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).

## SPECIAL NOTES TO READER

**Boe and Bcfe Conversions**

Boe amounts have been calculated by using the conversion ratio of 6 Mcf of natural gas to 1 bbl of oil and Bcfe amounts have been calculated by using the conversion ratio of 1 bbl of oil to 6 Mcf of natural gas. Boe and Bcfe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1 bbl and a Bcfe conversion ratio of 1 bbl to 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 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

**Production**

With respect to the disclosure of Birchcliff's production contained in this Annual Information Form: (i) references to "light oil" mean "light crude oil and medium crude oil" as such term is defined in NI 51-101; (ii) references to "liquids" means a combination of one or more of light oil, condensate and other NGLs; and (iii) references to "natural gas" mean "shale gas", which also includes an immaterial amount of "conventional natural gas", as such terms are defined in NI 51-101. In addition, NI 51-101 includes condensate within the product type of natural gas liquids. Birchcliff has disclosed condensate separately from other natural gas liquids as the price of condensate as compared to other natural gas liquids is currently significantly higher and Birchcliff believes presenting the two commodities separately provides a more accurate description of its operations and results therefrom.

**Resource (Drilling) Locations**

This Annual Information Form discloses a total of 2,293 contingent development pending resource locations on the Montney/Doig Resource Play as disclosed in Appendix A to this Annual Information Form, which represent the number of wells forecast to be drilled under the development plans for Birchcliff's contingent resource development pending projects. None of these locations have any reserves attributed to them in the Consolidated Reserves Report. These locations were estimated by Deloitte based on Birchcliff's prospective (i.e. potential) acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and an evaluation of applicable geological, seismic, engineering, production and reserves information. Birchcliff's ability to drill and develop these locations and the drilling locations on which Birchcliff actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, the net prices received for commodities produced, regulatory approvals and regulatory changes. In addition, there are contingencies that prevent contingent resources from being classified as reserves and there is uncertainty that it will be commercially viable to produce any portion of the Corporation's contingent resources. As a result of these uncertainties, there can be no assurance that these resource locations will ever be drilled or result in additional reserves or production for the Corporation. See *"Presentation of Oil and Gas Reserves and Resources"*, *"Risk Factors – Uncertainty of Reserves and Resource Estimates"* and *"Risk Factors – Potential Future Drilling Locations"* and Appendix A.

**Forward-Looking Statements**

Certain statements contained in this Annual Information Form constitute forward-looking statements and forward-looking information (collectively referred to as "**forward-looking statements**") within the meaning of applicable Canadian securities laws. The forward-looking statements contained in this Annual Information Form relate to future events or Birchcliff's future plans, operations or performance and are based on Birchcliff's current expectations, estimates, projections, beliefs and assumptions. Such forward-looking statements have been made by Birchcliff in light of the information available to it at the time the statements were made and reflect its experience and perception of historical trends. All statements and information other than historical fact may be forward-looking statements. Such forward-looking statements are often, but not always, identified by the use of words such as "seek", "plan", "focus", "future", "outlook", "position", "expect", "project", "intend", "believe", "anticipate", "estimate", "forecast", "guidance", "potential", "proposed", "predict", "budget", "continue", "targeting", "may", "will", "could", "might", "should", "would", "on track" and other similar words and expressions.

By their nature, forward-looking 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. Accordingly, readers are cautioned not to place undue reliance on such forward-looking statements. Although Birchcliff believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct and Birchcliff makes no representation that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements.

In particular, this Annual Information Form contains forward-looking statements relating to the following: Birchcliff's plans and other aspects of its anticipated future financial performance, results, operations, focus, objectives, strategies, opportunities, priorities and goals (including that Birchcliff is focused on its high-quality Montney/Doig Resource Play); statements regarding the Revised 2020 Capital Program and the Corporation's proposed exploration and development activities and the timing thereof (including: estimates of capital expenditures; the number and locations of wells to be drilled and brought on production; and that Birchcliff may further adjust the program to respond to changes in commodity prices and other material changes in the assumptions underlying the program); Birchcliff's expectation that the commodity price environment and economic and industry conditions will continue to influence the general development of its business in 2020; statements regarding potential acquisitions and dispositions of assets; statements regarding the Inlet Liquids-Handling Facility (including: the capacity of the facility; the anticipated timing for the completion of the facility; and that the facility will give Birchcliff the ability to grow its condensate production to 10,000 bbls/d in Pouce Coupe); the performance and other characteristics of Birchcliff's oil and natural gas properties and expected results from its assets (including: the potential of Birchcliff's Montney/Doig Resource Play; and statements that the Montney/Doig Resource Play is large enough to provide Birchcliff with an extensive inventory of repeatable and low-cost drilling opportunities that the Corporation expects will provide production and reserves growth for many years); Birchcliff's competitive position; Birchcliff's processing, transportation and marketing arrangements, strategies and activities (including: the Corporation's ability to mitigate the impact of production curtailments on the NGTL System; that the Corporation enters into firm service obligations for the transportation and processing of its natural gas, oil and NGLs production volumes in order to secure access to the infrastructure necessary to transport and process such volumes and renews, amends or enters into new firm service agreements from time to time; and the Corporation's belief that it should generally secure firm transportation sufficient for its current and future growth plans); Birchcliff's hedging activities, risk management strategy and use of risk management techniques; that Birchcliff has the ability to increase its natural gas production should commodity prices and economic conditions improve; the treatment under and the impact of existing and proposed governmental regulatory regimes and tax laws, including climate change and GHG legislation (including: the Corporation's expectation that it will receive emission performance credits for 2019; statements that at the present time, the operational and financial impacts of complying with applicable GHG legislation are not material to the Corporation; and the Corporation's expectation that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term, potentially reducing the demand for oil and natural gas resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets); estimates of decommissioning obligations; the information set forth under the heading *"Statement of Reserves Data and Other Oil and Gas Information"* and elsewhere in this Annual Information Form as it relates to the Corporation's reserves (including: estimates of reserves; estimates of the net present values of future net revenue associated with Birchcliff's reserves; forecasts for prices, inflation and exchange rates; development plans for the Corporation's undeveloped reserves and the timing for the development of such reserves, including the number of wells forecast to be drilled and forecast facility expansions; abandonment and reclamation costs; future development costs, the anticipated funding of such costs and the Corporation's expectation that interest or other funding costs would not make the development of any of its properties uneconomic; statements regarding wells that are currently non-producing and the anticipated timing for such wells to be brought on production; the amount of undeveloped lands on which Birchcliff expects the rights to explore, develop and exploit will expire within one year; Birchcliff's forward contracts and transportation and processing commitments; Birchcliff's income tax horizon and estimates of tax pools; and estimates of production); industry conditions pertaining to the oil and natural gas industry; expectations regarding commodity prices and costs and supply and demand for oil and natural gas; expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions and development; Birchcliff's dividend policy and the payment of dividends; statements relating to the Corporation's normal course issuer bid (including potential purchases under the bid and the cancellation of Common Shares purchased under the bid); statements regarding Birchcliff's Credit Facilities (including the timing of semi-annual reviews); and the information set forth in Appendix A and elsewhere in this Annual Information Form as it relates to the Corporation's resources (including: estimates of Birchcliff's contingent resources, prospective resources and PIIP; estimates of the net present value of the best estimate of Birchcliff's development pending contingent resources; information regarding Birchcliff's development pending contingent resource projects, including development plans; estimates of the total costs to achieve commercial production and to fully develop a project; the timelines of such projects; estimates of the dates of first commercial production; estimates of resource locations; and expectations regarding the resolution of contingencies for Birchcliff's contingent resources). Statements relating to reserves and resources are forward-looking as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. See *"Presentation of Oil and Gas Reserves and Resources".*

With respect to the forward-looking statements contained in this Annual Information Form, assumptions have been made regarding, among other things: prevailing and future commodity prices and differentials, currency exchange rates, interest rates, inflation rates, royalty rates and tax rates; the state of the economy, financial markets and the exploration, development and production business; the political environment in which Birchcliff operates; the regulatory framework regarding royalties, taxes, environmental, climate change and other laws; the Corporation's ability to comply with existing and future environmental, climate change and other laws; future cash flow, debt and dividend levels; future operating, transportation, marketing, general and administrative and other expenses; Birchcliff's ability to access capital and obtain financing on acceptable terms; the timing and amount of capital expenditures and the sources of funding for capital expenditures and other activities; the sufficiency of budgeted capital expenditures to carry out planned operations; the successful and timely implementation of capital projects and the timing, location and extent of future drilling and other operations; results of operations; Birchcliff's ability to continue to develop its assets and obtain the anticipated benefits therefrom; the performance of existing and future wells; the success of new wells drilled; reserves and resource volumes and Birchcliff's ability to replace and expand reserves through acquisition, development or exploration; the impact of competition on Birchcliff; the availability of, demand for and cost of labour, services and materials; the ability to obtain any necessary regulatory or other approvals in a timely manner; the satisfaction by third parties of their obligations to Birchcliff; the ability of Birchcliff to secure adequate processing and transportation for its products; Birchcliff's ability to successfully market natural gas and liquids; the availability of hedges on terms acceptable to Birchcliff; and Birchcliff's natural gas market exposure. In addition to the foregoing assumptions, Birchcliff has made the following assumptions with respect to certain forward-looking statements contained in this Annual Information Form:

- Birchcliff's 2020 guidance (as updated March 11, 2020) assumes the following commodity prices and exchange rate: an average WTI spot price of US$48.00/bbl; an average WTI-MSW differential of CDN$5.70/bbl; an average AECO 5A spot price of CDN$1.90/GJ; an average Dawn spot price of US$2.15/MMBtu; an average NYMEX Henry Hub spot price of US$2.20/MMBtu; and an exchange rate (CDN$ to US$1) of 1.34.

- With respect to estimates of 2020 capital expenditures and Birchcliff's spending plans for 2020, such estimates and plans assume that the Revised 2020 Capital Program will be carried out as currently contemplated. Birchcliff makes acquisitions and dispositions in the ordinary course of business. Any acquisitions and dispositions completed could have an impact on Birchcliff's capital expenditures, production, cash flow, costs and debt, which impact could be material. The amount and allocation of capital expenditures for exploration and development activities by area and the number and types of wells to be drilled and brought on production is dependent upon results achieved and is subject to review and modification by management on an ongoing basis throughout the year. Actual spending may vary due to a variety of factors, including commodity prices, economic conditions, results of operations and costs of labour, services and materials.

- With respect to statements of future wells to be drilled and brought on production and estimates of resource locations, the key assumptions are: the continuing validity of the geological and other technical interpretations performed by Birchcliff's technical staff, which indicate that commercially economic volumes can be recovered from Birchcliff's lands as a result of drilling future wells; and that commodity prices and general economic conditions will warrant proceeding with the drilling of such wells.

- With respect to statements regarding the future potential and prospectivity of properties and assets, such statements assume: the continuing validity of the geological and other technical interpretations determined by Birchcliff's technical staff with respect to such properties; and that, over the long-term, commodity prices and general economic conditions will warrant proceeding with the exploration and development of such properties.

- With respect to estimates of reserves, resources and the net present values of future net revenue associated with Birchcliff's reserves and its best estimate of development pending contingent resources, the key assumption is the validity of the data used by Deloitte and McDaniel in their independent reserves evaluations.

Birchcliff's actual results, performance or achievements could differ materially from those anticipated in the forward-looking statements as a result of both known and unknown risks and uncertainties including, but not limited to: general economic, market and business conditions which will, among other things, impact the demand for and market prices of Birchcliff's products and Birchcliff's access to capital; volatility of crude oil and natural gas prices; fluctuations in currency exchange and interest rates; stock market volatility; the risks posed by pandemics and epidemics and their impacts on supply and demand and commodity prices; loss of market demand; an inability to access sufficient capital from internal and external sources on terms acceptable to the Corporation; fluctuations in the costs of borrowing; operational risks and liabilities inherent in oil and natural gas operations; the occurrence of unexpected events such as fires, severe weather, explosions, blow-outs, equipment failures, transportation incidents and other similar events affecting Birchcliff or other parties whose operations or assets directly or indirectly affect Birchcliff; an inability to access sufficient water or other fluids needed for operations; uncertainty that development activities in connection with Birchcliff's assets will be economic; an inability to access or implement some or all of the technology necessary to efficiently and effectively operate its assets and achieve expected future results; uncertainties associated with estimating oil and natural gas reserves and resources; the accuracy of estimates of reserves, future net revenue and production levels; geological, technical, drilling, construction and processing problems; uncertainty of geological and technical data; horizontal drilling and completions techniques and the failure of drilling results to meet expectations for reserves or production; uncertainties related to Birchcliff's future potential drilling locations; delays or changes in plans with respect to exploration or development projects or capital expenditures, including delays in the completion of gas plants and other facilities; the accuracy of cost estimates and variances in Birchcliff's actual costs and economic returns from those anticipated; incorrect assessments of the value of acquisitions and exploration and development programs; changes to the regulatory framework in the locations where the Corporation operates, including changes to tax laws, Crown royalty rates, environmental laws, climate change laws, carbon tax regimes, incentive programs and other regulations that affect the oil and natural gas industry and other actions by government authorities; an inability of the Corporation to comply with existing and future environmental, climate change and other laws; the cost of compliance with current and future environmental laws; political uncertainty and uncertainty associated with government policy changes; dependence on facilities, gathering lines and pipelines, some of which the Corporation does not control; uncertainties and risks associated with pipeline restrictions and outages to third-party infrastructure that could cause disruptions to production; the lack of available pipeline capacity and an inability to secure adequate and cost-effective processing and transportation for Birchcliff's products; an inability to satisfy obligations under Birchcliff's firm marketing and transportation arrangements; a failure to comply with covenants under Birchcliff's credit facilities; shortages in equipment and skilled personnel; the absence or loss of key employees; competition for, among other things, capital, acquisitions of reserves, undeveloped lands, equipment and skilled personnel; management of Birchcliff's growth; environmental and climate change risks, claims and liabilities; potential litigation; default under or breach of agreements by counterparties and potential enforceability issues in contracts; claims by Indigenous peoples; the reassessment by taxing or regulatory authorities of the Corporation's prior transactions and filings; unforeseen title defects; third-party claims regarding the Corporation's right to use technology and equipment; uncertainties associated with the outcome of litigation or other proceedings involving Birchcliff; uncertainties associated with credit facilities and counterparty credit risk; risks associated with Birchcliff's risk management activities and the risk that hedges on terms acceptable to Birchcliff may not be available; risks associated with the declaration and payment of future dividends, including the discretion of Birchcliff's Board to declare dividends and change the Corporation's dividend policy; the failure to obtain any required approvals in a timely manner or at all; the failure to complete or realize the anticipated benefits of acquisitions and dispositions and the risk of unforeseen difficulties in integrating acquired assets into Birchcliff's operations; negative public perception of the oil and natural gas industry and fossil fuels, including transportation and hydraulic fracturing involving fossil fuels; the Corporation's reliance on hydraulic fracturing; market competition, including from alternative energy sources; changing demand for petroleum products; the availability of insurance and the risk that certain losses may not be insured; breaches or failure of information systems and security (including risks associated with cyber-attacks); risks associated with the ownership of the Corporation's securities; the accuracy of the Corporation's accounting estimates and judgments; and potential requirements under applicable accounting standards for the impairment or reversal of estimated recoverable amounts of the Corporation's assets from time to time.

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other risk factors that could affect results of operations, financial performance or financial results are included under the heading *"Risk Factors"* in this Annual Information Form and in other reports filed with Canadian securities regulatory authorities from time to time.

This Annual Information Form may contain information that constitutes future-orientated financial information or financial outlook information (collectively, "**FOFI**") about Birchcliff's prospective results of operations, all of which is subject to the same assumptions, risk factors, limitations and qualifications as set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on FOFI. Birchcliff's actual results, performance and achievements could differ materially from those expressed in, or implied by, FOFI. Birchcliff has included FOFI in order to provide readers with a more complete perspective on Birchcliff's future operations and management's current expectations relating to Birchcliff's future performance. Readers are cautioned that such information may not be appropriate for other purposes. FOFI contained herein was made as of the date of this Annual Information Form. Unless required by applicable laws, Birchcliff does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Management has included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide readers with a more complete perspective on Birchcliff's future operations and management's current expectations relating to Birchcliff's future performance. Readers are cautioned that this information may not be appropriate for other purposes.

The forward-looking statements contained in this Annual Information Form are expressly qualified by the foregoing cautionary statements. The forward-looking statements contained herein are made as of the date of this Annual Information Form. Unless required by applicable laws, Birchcliff does not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

**Access to Documents**

Any document referred to in this Annual Information Form and described as being filed on the Corporation's SEDAR profile at www.sedar.com may be obtained free of charge from Birchcliff at Suite 1000, 600 – 3rd Avenue S.W., Calgary, Alberta  T2P 0G5.

## CORPORATE STRUCTURE

The Corporation was incorporated on July 6, 2004 under the ABCA as "1116463 Alberta Ltd." and on September 10, 2004, the Corporation amended its articles to change its name to "Birchcliff Energy Ltd." On January 18, 2005, the Corporation amalgamated under the ABCA with Scout Capital Corp., a public corporation, pursuant to a plan of arrangement under the ABCA to form an amalgamated corporation under the name "Birchcliff Energy Ltd." On May 31, 2005, the Corporation amalgamated under the ABCA with Veracel, a private company, pursuant to a plan of arrangement under the ABCA to form an amalgamated corporation under the name "Birchcliff Energy Ltd."

On August 3, 2012, the Corporation amended its articles to create the Series A Preferred Shares and the Series B Preferred Shares. On June 13, 2013, the Corporation amended its articles to create the Series C Preferred Shares. See *"Description of Capital Structure – Authorized Share Capital and Securities Outstanding – Preferred Shares"*.

The registered and head office of the Corporation is located at Suite 1000, 600 – 3rd Avenue S.W., Calgary, Alberta T2P 0G5.

The Corporation does not have any subsidiaries.

## GENERAL DEVELOPMENT OF THE BUSINESS

### Three Year History

A description of the significant developments in the business of the Corporation over the last three completed financial years is set forth below.

***2017***

On February 8, 2017, the Corporation announced that the Board had approved a capital budget of $355.0 million for 2017.

On March 1, 2017, the Corporation announced that the Board had declared a quarterly cash dividend of $0.025 per Common Share for the quarter ending March 31, 2017. This was the first dividend paid by the Corporation on its Common Shares. See *"Dividend and Distribution Policy".*

On March 21, 2017, the Corporation announced that it would pursue the sale of its Charlie Lake light oil resource play (the "**Charlie Lake Light Oil Resource Play**"). The Corporation subsequently disposed of the majority of its assets on the Charlie Lake Light Oil Resource Play pursuant to the Worsley Disposition, which closed on August 31, 2017, and the Progress Disposition, which closed on October 2, 2017, as discussed in further detail below.

On March 27, 2017, the Corporation announced that it had entered into agreements with TCPL for the firm service transportation of an aggregate of 175,000 GJ/d of natural gas on TCPL's Canadian Mainline. See *"Description of the Business – Transportation Arrangements – Natural Gas".*

On May 10, 2017, the Corporation and its syndicate of lenders agreed to an extension of the maturity dates of each of the Syndicated Credit Facility and the Working Capital Facility from May 11, 2018 to May 11, 2020 and to the borrowing base remaining unchanged at $950.0 million.

On May 11, 2017, Mr. James W. Surbey was elected as a director of the Corporation at the annual and special meeting of shareholders. On June 30, 2017, Mr. Surbey retired as the Vice-President, Corporate Development and Corporate Secretary of the Corporation.

On August 1, 2017, the Corporation announced that it had entered into a definitive purchase and sale agreement with a private oil and gas company with respect to the Worsley Disposition. On August 31, 2017, the Corporation completed the Worsley Disposition for total consideration of approximately $100.0 million (before adjustments), consisting of: (i) cash consideration of $90.0 million; and (ii) securities of affiliates of the purchaser with a total value of $10.0 million.

On August 10, 2017, the Corporation announced that it had entered into a definitive purchase and sale agreement with respect to the Progress Disposition and that the Board had approved an increased capital budget of $404.0 million for 2017.

In September 2017, Phase V of the Pouce Coupe Gas Plant commenced operations, increasing the total processing capacity of the Pouce Coupe Gas Plant to 260 MMcf/d from 180 MMcf/d.

On October 2, 2017, the Corporation completed the Progress Disposition for total consideration of $31.7 million (before adjustments).

On November 8, 2017, Ms. Debra A. Gerlach was appointed as a director of the Corporation.

***2018***

On February 14, 2018, the Corporation announced that the Board had approved a capital budget of $255.0 million for 2018.

On April 3, 2018, the Corporation and AltaGas announced that they had entered into a definitive agreement for a new long-term natural gas processing arrangement (the "**Gordondale Processing Arrangement**") effective January 1, 2018 for natural gas processed at the Gordondale Gas Plant. See *"Description of the Business – Processing Arrangements – Gordondale Key Operating Area".*

On April 27, 2018, the Corporation and its syndicate of lenders agreed to an extension of the maturity dates of each of the Syndicated Credit Facility and the Working Capital Facility from May 11, 2020 to May 11, 2021 and to the borrowing base remaining unchanged at $950.0 million. In addition, the Corporation and the lenders agreed to increase the Working Capital Facility to $100.0 million (from $50.0 million), with a corresponding reduction in the Syndicated Credit Facility to $850.0 million (from $900.0 million).

On May 10, 2018, Mr. Larry A. Shaw ceased to be a director of the Corporation as he did not stand for re-election at the Corporation's annual and special meeting of shareholders held on the same date.

In August 2018, Phase VI of the Pouce Coupe Gas Plant commenced operations, increasing the total processing capacity of the Pouce Coupe Gas Plant to 340 MMcf/d from 260 MMcf/d.

On November 14, 2018, the Corporation announced that it had entered into a definitive purchase and sale agreement with respect to the Pouce Coupe Acquisition, which acquisition subsequently closed on January 3, 2019. See *"General Development of the Business – Three Year History – 2019".* The Corporation also announced an increased capital budget of $288.0 million for 2018.

On December 14, 2018, Ms. Stacey E. McDonald was appointed as a director of the Corporation and Ms. Rebecca J. Morley resigned as a director of the Corporation.

***2019***

On January 3, 2019, the Corporation completed the Pouce Coupe Acquisition. Pursuant to the Pouce Coupe Acquisition, the Corporation acquired 18 gross (15.1 net) contiguous sections of Montney land located between the Corporation's existing Pouce Coupe and Gordondale properties, as well as various other non-Montney lands and other assets, for total cash consideration of $39.0 million.

On February 13, 2019, the Corporation announced that the Board had approved a capital budget of $204.0 million for 2019 and a quarterly cash dividend of $0.02625 on its Common Shares for the quarter ending March 31, 2019, which represented a 5% increase over the prior quarter.

On May 10, 2019, the Corporation and its syndicate of lenders agreed to: (i) an extension of the maturity dates of each of the Syndicated Credit Facility and the Working Capital Facility from May 11, 2021 to May 11, 2022; and (ii) increase the borrowing base limit to $1.0 billion from $950.0 million, with the Syndicated Credit Facility being increased to $900.0 million from $850.0 million and the Working Capital Facility remaining at $100.0 million. For additional information regarding the Credit Facilities, see "*Description of Capital Structure – Credit Facilities"*.

On August 14, 2019, the Corporation announced that it had increased its capital budget for 2019 to $242.0 million.

**Recent Developments**

On January 22, 2020, the Corporation announced that the Board had approved a capital budget of $340.0 million to $360.0 million for 2020 which contemplated the drilling of 38 (38.0 net) wells and the bringing on production of 44.0 (44.0 net) wells during 2020 and the completion of the Corporation's 20,000 bbls/d (50% condensate, 50% water) inlet liquids-handling facility at the Pouce Coupe Gas Plant (the "**Inlet Liquids-Handling Facility**").

On March 11, 2020, as a result of weakening and volatile oil prices, the Corporation announced that the Board had approved a reduced capital budget of $275.0 million to $295.0 million for 2020. The reduction in capital spending primarily relates to the deferral of 10 (10.0 net) oil wells that were originally planned to be drilled and brought on production in Gordondale in 2020. Birchcliff's revised capital program for 2020 (the "**Revised 2020 Capital Program**") now contemplates the drilling of a total of 28 (28.0 net) wells and the bringing on production of a total of 34 (34.0 net) wells, with facilities and infrastructure and other spending remaining largely unchanged.

Birchcliff expects that the commodity price environment and economic and industry conditions will continue to influence the general development of its business in 2020. Birchcliff will continue to closely monitor economic conditions and commodity prices and, where deemed prudent, will further adjust the Revised 2020 Capital Program to respond to changes in commodity prices and other material changes in the assumptions underlying such program. In addition, the Corporation may make adjustments to its other business activities as appropriate. See *"Special Notes to Reader – Forward-Looking Statements".*

**Significant Acquisitions**

The Corporation did not complete any significant acquisitions during the financial year ended December 31, 2019 for which disclosure is required under Part 8 of NI 51-102.

The Corporation evaluates potential acquisitions of all types of petroleum and natural gas and other energy-related assets and/or companies as part of its ongoing business and is regularly in the process of evaluating several potential acquisitions at any one time, which individually or together could be material. Birchcliff cannot predict whether any current or future opportunities will result in one or more acquisitions for the Corporation. In addition, the Corporation may in the future complete financings of equity or debt (which may be convertible into equity) for purposes that may include financing of acquisitions, Birchcliff's operations and capital expenditures and the repayment of indebtedness. See *"Risk Factors".*

## DESCRIPTION OF THE BUSINESS

**General**

The Corporation is an intermediate oil and natural gas company based in Calgary, Alberta that is engaged in the business of exploring for, developing and producing natural gas, light oil, condensate and other NGLs in the Western Canadian Sedimentary Basin with operations concentrated within its one core area, the Peace River Arch of Alberta.

Within the Peace River Arch, Birchcliff is focused on its high-quality Montney/Doig Resource Play and the exploration and development of its low-cost, liquids-rich natural gas and light oil assets on the play. The Corporation's Montney/Doig Resource Play is large enough to provide it with an extensive inventory of repeatable and low-cost drilling opportunities that the Corporation expects will provide production and reserves growth for many years. Within the Montney/Doig Resource Play, the Corporation's operations are primarily concentrated in the Pouce Coupe and Gordondale areas of Alberta where it owns large contiguous blocks of high working interest land. At December 31, 2019, the Corporation operated 99% of its production. In addition, the Corporation owns and controls many of the significant facilities and infrastructure it relies upon to handle the majority of its production, including its 100% owned and operated Pouce Coupe Gas Plant.

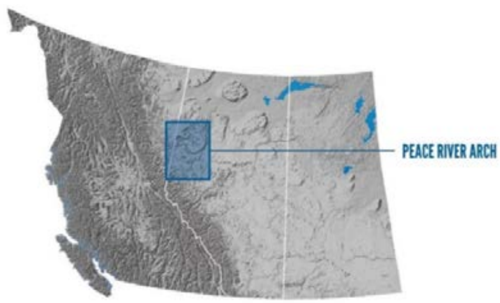
The Common Shares, the Series A Preferred Shares and the Series C Preferred Shares are listed for trading on the TSX under the trading symbols "BIR", "BIR.PR.A" and "BIR.PR.C", respectively.

**Principal Properties**

The following is a description of the Corporation's principal oil and natural gas properties as at December 31, 2019. Unless otherwise stated, production volumes presented below are the Corporation's average gross sales volumes for the period indicated, meaning Birchcliff's working interest (operating or non-operating) share before the deduction of royalties and without including any royalty interests of Birchcliff.

***Peace River Arch***

Birchcliff's operations are concentrated within its one core area, the Peace River Arch, which is centred northwest of Grande Prairie, Alberta, adjacent to the Alberta/British Columbia border. The Peace River Arch is generally characterized by multiple horizons with a myriad of structural, stratigraphic and hydrodynamic traps. The Peace River Arch is highlighted by the Deep Basin hydrocarbon trapping phenomena. The Deep Basin is a hydrodynamic or permeability trap where the water in the updip position cannot travel through the fine grained reservoirs with characteristics that include overpressured reservoirs, continuous hydrocarbon columns and low water production, with low terminal declines. The Peace River Arch provides all-season access that allows the Corporation to drill, equip and tie-in wells on an almost continuous basis.




***The Montney/Doig Resource Play***

<u>Overview</u>

The Montney/Doig Resource Play is considered by management to be one of the premier resource plays in North America. Birchcliff's Montney/Doig Resource Play is centred approximately 95 km northwest of Grande Prairie, Alberta. At December 31, 2019, Birchcliff held 413.2 gross sections of land on the Montney/Doig Resource Play. During the financial year ended December 31, 2019, the Montney/Doig Resource Play accounted for essentially 100% of the Corporation's production, capital expenditures and reserves.

Within the Montney/Doig Resource Play, the Corporation is focused on two key operating areas, Pouce Coupe and Gordondale. These two key operating areas are largely contiguous and collectively accounted for essentially 100% of the Corporation's total annual average production in 2019. The Corporation has established two geographically-organized teams, the Pouce Coupe team and the Gordondale team, to manage these two key operating areas. Each team has a full complement of highly-skilled technical professionals, including engineers, geoscientists and landmen.

<u>Attributes</u>

Birchcliff characterizes its Montney/Doig Resource Play as a regionally pervasive, continuous, low-permeability hydrocarbon accumulation or system that typically requires intensive stimulation to produce. The production characteristics of this play generally include steep initial declines that rapidly trend to much lower decline rates, yielding long-life production. The play exhibits a statistical distribution of estimated ultimate recoveries and therefore provides a repeatable distribution of drilling opportunities. Birchcliff's Montney/Doig Resource Play is ideally suited for the application of horizontal drilling and multi-stage fracture stimulation technology.

As more wells are drilled into a resource play, there is a substantial decrease in both the geological and technical risks. Over the past 15 years, Birchcliff has worked to de-risk its Montney/Doig Resource Play by drilling both vertical and horizontal exploration wells in order to develop an in-depth understanding of the oil and gas pools, rock properties and petrophysical characteristics and reservoir parameters. The Corporation designs, tests and evaluates its drilling, completion and production technologies and practices to achieve continual improvements in productivity and expected ultimate recoveries in order to drive down capital and operating costs. The Corporation's pool delineation strategy de-risks future development and helps to reduce future costs as new well pads and infrastructure are designed and built to support multiple horizontal well locations and increased production.

*Geology*

The Montney/Doig Resource Play in Birchcliff's areas of operations is approximately 300 metres (1,000 feet) thick. The play has a large areal extent covering in excess of 50,000 square miles. The Montney/Doig is composed of a high percentage of hard minerals and a very low percentage of clay minerals resulting in excellent "fracability". This, combined with the current stress regime, results in the rock shattering more like glass in a complex fracture style versus a simple bi-wing style. The rock parameters also yield excellent fracture stability; the fractures stay open due to low proppant embedment. This is a key contributing factor to the low terminal declines and large estimated ultimate recoveries of the play. Unlike most shale plays that are predominantly shale, the Montney/Doig is classified by management as a hybrid resource play because it is comprised of hydrocarbon-saturated rock with both tight silt and sand reservoir rock interlayered with shale source rock. This results in relatively high permeability and productivity rates.

Hydrodynamics is another important attribute for resource plays. A large portion of the Montney/Doig Resource Play is over-pressured which reduces the potential for significant water production. The Pouce Coupe and Gordondale areas are predominantly over-pressured which also results in higher hydrocarbons in-place. The Montney and a majority of the Doig were deposited in a lower to middle shore face environment that is regionally extensive and results in a widespread style deposit that provides for more repeatable results.

The Montney/Doig Resource Play exists in two geological formations (the Montney and the Doig) and Birchcliff has divided the geologic column in its areas of operations into six drilling intervals from the youngest (top) to the oldest (bottom): (i) the Basal Doig/Upper Montney; (ii) the Montney D4; (iii) the Montney D3; (iv) the Montney D2; (v) the Montney D1; and (vi) the Montney C. Part of Birchcliff's long-term strategy is to continue to explore and delineate the Montney/Doig Resource Play, both geographically and stratigraphically. At December 31, 2019, the Corporation has successfully drilled and cased an aggregate of 425.0 (417.4 net) Montney/Doig horizontal wells on the Montney/Doig Resource Play. Of these wells, an aggregate of 413.0 (406.2 net) wells have been completed and brought on production, consisting of 74 (72.2 net) wells in the Basal Doig/Upper Montney interval, 12 (12.0 net) wells in the Montney D4 interval, 33 (33.0 net) wells in the Montney D2 interval, 291 (286.0 net) wells in the Montney D1 interval and 3 (3.0 net) wells in the Montney C interval. To date, the Corporation has not drilled any wells in the Montney D3 interval.

*Key Operating Areas*

The following is a brief description of the Corporation's two key operating areas:

Pouce Coupe

The Pouce Coupe key operating area is located west and northwest of Grande Prairie, Alberta and consists of the Corporation's properties in Pouce Coupe and Elmworth. At December 31, 2019, the Corporation held an aggregate of 407.7 (376.6 net) sections of land in the area. Annual average production in 2019 was 50,616 boe/d (274,009 MMcf/d of natural gas, 986 bbls/d of NGLs (excluding condensate) and 3,963 bbls/d of condensate). In 2019, the Pouce Coupe key operating area accounted for approximately:

- 60% of the Corporation's total capital expenditures;
- 65% of the Corporation's total corporate annual average production; and
- 75% of the Corporation's total annual average natural gas production, 14% of the Corporation's total annual average NGLs production (excluding condensate) and 77% of the Corporation's total annual average condensate production.

In 2019, the Corporation drilled 16 (16.0 net) Montney/Doig horizontal natural gas wells in the Pouce Coupe area and brought 17 (17.0 net) wells on production. The Corporation's Revised 2020 Capital Program contemplates the drilling of 20 (20.0 net) wells and the bringing on production of 24 (24.0 net) wells in Pouce Coupe in 2020 and completing the Inlet Liquids-Handling Facility. See *"General Development of the Business – Recent Developments"* for further information regarding the Revised 2020 Capital Program.

Significant infrastructure used by Birchcliff in the area includes the Pouce Coupe Gas Plant. See *"Description of the Business – Facilities"* and *"Description of the Business – Processing Arrangements"* for further information regarding the Pouce Coupe Gas Plant.

<u>Gordondale</u>

The Gordondale key operating area is located northwest of Grande Prairie, Alberta and consists of the Corporation's properties in Gordondale and Progress. At December 31, 2019, the Corporation held an aggregate of 148.5 (93.4 net) sections of land in the area. Annual average production in 2019 was 27,357 boe/d (90,947 MMcf/d of natural gas, 4,686 bbls/d of light oil, 6,278 bbls/d of NGLs (excluding condensate) and 1,235 bbls/d of condensate). In 2019, the Gordondale key operating area accounted for approximately:

- 39% of the Corporation's total capital expenditures;
- 35% of the Corporation's total corporate annual average production; and
- 25% of the Corporation's total annual average natural gas production, 99% of the Corporation's total annual average light oil production, 86% of the Corporation's total annual average NGLs production (excluding condensate) and 23% of the Corporation's total annual average condensate production.

In 2019, the Corporation drilled 14 (14.0 net) Montney horizontal oil wells in the Gordondale area and brought 16 (16.0 net) wells on production. The Corporation's Revised 2020 Capital Program contemplates the drilling of 8 (8.0 net) wells and the bringing on production of 10 (10.0 net) wells in Gordondale in 2020. See *"General Development of the Business – Recent Developments"* for further information regarding the Revised 2020 Capital Program.

Significant infrastructure used by Birchcliff in the area includes AltaGas' Gordondale Gas Plant and Pembina's fractionation facility at Redwater, Alberta (the "**Pembina Facility**"). See *"Description of the Business – Processing Arrangements"* for further information regarding Birchcliff's processing arrangements at these facilities.

**Other Properties**

In addition to Pouce Coupe and Gordondale, the Corporation also has other miscellaneous properties, none of which are material to the Corporation. Annual average production in 2019 for the Corporation's other properties represented less than 0.01% of the Corporation's total annual average production.

**Landholdings**

The Corporation's land base primarily consists of large contiguous blocks of high working interest acreage located near facilities owned and/or operated by Birchcliff or near third-party infrastructure. The Corporation's land activities during 2019 included: (i) the acquisition of 138.3 (119.0 net) sections of Crown and third-party lands, including 28.3 (19.0 net) sections pursuant to the Pouce Coupe Acquisition; and (ii) the disposition of 9.8 (4.8 net) sections of land pursuant to various non-core dispositions. The Corporation's undeveloped land base at December 31, 2019 was 220,629.4 (193,049.6 net) acres, or 344.7 (301.6 net) sections, with an 87% average working interest.

**Drilling Program and Technology**

During 2019, Birchcliff drilled 30 (30.0 net) wells and brought 33 (33.0 net) wells on production as set forth in the table below:

| Area | Total Wells Drilled in 2019 | Total Wells Brought on Production 2019(1) |
|---|---|---|
| **Pouce Coupe** | | |
| Montney D1 horizontal natural gas wells | 9 | 14 |
| Montney D2 horizontal natural gas wells | 5 | 2 |
| Montney C horizontal natural gas wells | 2 | 1 |
| **Total – Pouce Coupe** | **16** | **17** |
| | | |
| **Gordondale** | | |
| Montney D4 horizontal oil wells | 1 | |
| Montney D2 horizontal oil wells | 7 | 9 |
| Montney D1 horizontal oil wells | 6 | 7 |
| **Total – Gordondale** | **14** | **16** |
| **TOTAL – COMBINED** | **30** | **33** |

(1) Includes 9 (9.0) net wells that were drilled and rig released in Q4 2018.

All wells drilled in 2019 were drilled on multi-well pads, which allows Birchcliff to reduce its per well costs and environmental footprint. Birchcliff actively employs the evolving technology utilized by the industry regarding horizontal well drilling and the related multi-stage fracture stimulation technology.

## Facilities

The following table sets forth the major facilities in which the Corporation held an interest at December 31, 2019:

| Facility Description(1) | Area and Location | Birchcliff Operated | Working Interest |
|---|---|---|---|
| Pouce Coupe Gas Plant | Pouce Coupe (03-22-78-12W6M) | Yes | 100% |
| Oil battery | Gordondale (02-06-79-11W6M) | Yes | 100% |
| Oil battery | Gordondale (07-29-78-11W6M) | Yes | 100% |
| Gas plant | Gordondale (01-01-78-10W6M) | No | ~13% |

(1) The Corporation does not have a working interest in either the Gordondale Gas Plant or the Pembina Facility. Accordingly, neither of these facilities are included in the table above.

At December 31, 2019, Birchcliff also held various interests in numerous other gas plants, oil batteries, compressors, facilities and infrastructure.

The following is a more detailed description of the Pouce Coupe Gas Plant:

### *Pouce Coupe Gas Plant*

Birchcliff's 100% owned and operated Pouce Coupe Gas Plant, which is currently licenced to process up to 340 MMcf/d of natural gas, is located in the heart of the Corporation's Montney/Doig Resource Play in the Pouce Coupe area. The strategically situated site for the Pouce Coupe Gas Plant enables the Corporation to control and operate all essential infrastructure from wellhead to sales point. The low per unit operating costs of the Pouce Coupe Gas Plant and related infrastructure give the Corporation a strong competitive advantage over other producers paying for third-party natural gas processing.

The Pouce Coupe Gas Plant was constructed in six separate phases as set forth in the table below:

| Phase | Phase Capacity | Total Combined Processing Capacity | Commencement of Operations |
|---|---|---|---|
| Phase I | 30 MMcf/d | 30 MMcf/d | March 2010 |
| Phase II | 30 MMcf/d | 60 MMcf/d | November 2010 |
| Phase III | 90 MMcf/d | 150 MMcf/d | October 2012 |
| Phase IV | 30 MMcf/d | 180 MMcf/d | September 2014 |
| Phase V | 80 MMcf/d | 260 MMcf/d | September 2017 |
| Phase VI | 80 MMcf/d | 340 MMcf/d | August 2018 |

In the fourth quarter of 2018, the Corporation completed the re-configuration of Phases V and VI to provide for shallow-cut capability which allows the Corporation to extract C3+ from the natural gas stream. In 2019, Birchcliff initiated the construction of the Inlet Liquids-Handling Facility in order to handle increased condensate volumes in

Pouce Coupe. Once completed, this facility will give Birchcliff the ability to increase its condensate production in the Pouce Coupe area to approximately 10,000 bbls/d. Fabrication of the various components and site preparation are underway and it is anticipated that the facility will be online in the third quarter of 2020.

The Pouce Coupe Gas Plant meets or exceeds all AER and Alberta Environment requirements. The facility employs energy efficient equipment to optimize performance and keep operating costs low. The Pouce Coupe Gas Plant uses an amine system to remove sulphur content and refrigeration to meet pipeline dew point specifications. Acid gas is injected into a high quality reservoir via two wells located at or adjacent to the site of the Pouce Coupe Gas Plant.

**Processing Arrangements**

***Pouce Coupe Key Operating Area***

The vast majority of the Corporation's natural gas production from Pouce Coupe is processed at the Pouce Coupe Gas Plant, with a *de minimis* amount being processed at third-party facilities. The natural gas processed at the Pouce Coupe Gas Plant is delivered via the NGTL System to NIT. The natural gas may then be sold at AECO or it may be delivered via the NGTL System to Empress, Alberta for transport to Dawn, Ontario via TCPL's Canadian Mainline, where it may then be sold. See *"Description of the Business – Transportation Arrangements".*

Condensate and other NGLs extracted from the natural gas stream at the Pouce Coupe Gas Plant are delivered to the Pembina Peace Pipeline by pipeline or truck.

***Gordondale Key Operating Area***

The vast majority of the Corporation's natural gas production from Gordondale is processed at the Gordondale Gas Plant, with a *de minimis* amount being processed at other third-party facilities. Under the Gordondale Processing Arrangement, Birchcliff is provided with up to 120 MMcf/d of natural gas processing on a firm service basis at the Gordondale Gas Plant and Birchcliff's take-or-pay obligation is 100 MMcf/d. The effective date of the Gordondale Processing Arrangement is January 1, 2018 and the term is for at least 15 years, subject to extension in accordance with the terms of the agreement. The natural gas processed at the Gordondale Gas Plant is delivered to NIT or Dawn in a similar manner as described above for Pouce Coupe.

NGLs (including condensate) extracted from the natural gas stream are primarily processed at the Pembina Facility where Birchcliff has access to and is responsible for the costs of 9,000 bbls/d of fractionation capacity.

The vast majority of the Corporation's light oil production from the Gordondale key operating area is processed at the Corporation's oil batteries and then delivered to the Pembina Peace Pipeline by pipeline or truck.

**Transportation Arrangements**

***Natural Gas***

The vast majority of the Corporation's natural gas production is transported to market on either the NGTL System to NIT or Empress, Alberta or on TCPL's Canadian Mainline to Dawn, Ontario. The Corporation employs a combination of firm and interruptible receipt pipeline service to deliver such production.

For 2020, the Corporation has approximately 511 MMcf/d of firm transportation receipt service on the NGTL System. The Corporation's transportation commitments are in excess of its forecast annual average natural gas production for 2020 as a result of excess processing capacity at the Pouce Coupe Gas Plant. This excess processing and transportation capacity gives the Corporation the ability to increase its natural gas production should commodity prices and economic conditions improve. It also allows the Corporation's current volumes to flow during most pipeline maintenance periods.

In March 2017, the Corporation entered into agreements with TCPL for the firm service transportation of an aggregate of 175,000 GJ/d of natural gas on TCPL's Canadian Mainline, whereby natural gas is transported from the Empress receipt point in Alberta to the Dawn trading hub located in Southern Ontario. The toll for the Empress to Dawn portion of the service is \$0.77/GJ plus fuel. The first tranche of this service (120,000 GJ/d) became available to Birchcliff on November 1, 2017, the second tranche (30,000 GJ/d) became available on November 1, 2018 and the third tranche (25,000 GJ/d) became available on November 1, 2019. Each tranche has a 10-year term.

The Pouce Coupe Gas Plant is also tied into the Alliance pipeline through Birchcliff's meter station located at Moose Creek, Alberta. Although the Corporation does not have transportation service on the Alliance pipeline, this connection provides the Corporation with the ability to try and purchase transportation service, either from Alliance directly or other third parties. Typically, such arrangements are done on a short-term basis and are subject to availability and Birchcliff being able to obtain an acceptable price for such service. These short-term arrangements can help the Corporation to mitigate the impact of production curtailments on the NGTL System.

***Light Oil and NGLs***

The vast majority of the Corporation's light oil production is transported on the Pembina Peace Pipeline to Edmonton, Alberta. The vast majority of the Corporation's NGLs production (including condensate) is transported on the Pembina Northern Pipeline to Fort Saskatchewan, Alberta.

**Marketing and Risk Management**

***Natural Gas***

The Corporation's natural gas production is primarily sold to third-party marketers at the AECO daily index price or the Dawn daily index price. Birchcliff also has sales agreements with a third-party marketer to sell and deliver into the Alliance pipeline system approximately 5 MMcf/d of natural gas under contracts which commenced April 1, 2017 and expire October 31, 2020, which is sold at Alliance's Trading Pool daily index price.

***Light Oil and NGLs***

The Corporation's light oil production is primarily sold to third-party marketers on a monthly basis. The pricing is either based on an index price or is a netback or posted price provided by the marketer.

The majority of the Corporation's NGLs production (including condensate) is currently sold to third-party marketers under contracts that commence on April 1 of the calendar year and run for one or two years. The pricing is typically based on available index prices.

The Corporation also has in place longer-term arrangements for the sale of NGLs. The Corporation sells ethane and propane under an agreement extending to 2026 pursuant to which ethane is sold at an indexed-based price and propane is priced at the buyer's posted propane price (the "**2026 Agreement**"). Birchcliff also has an agreement to sell propane to an affiliate of AltaGas whereby 50% of Birchcliff's excess propane (as such term is defined in the agreement) is sold on a firm basis from the date of commencement of commercial operations of AltaGas' Ridley Island Propane Export Terminal in British Columbia (which commenced operations May 2019) to the expiry of the 2026 Agreement, which then increases to 1,000 bbls/d until the end of the year in which the Gordondale Processing Arrangement expires. The propane is sold at an indexed-based price.

***Risk Management***

The Corporation also engages in risk management using financial instruments and physical delivery sales contracts which are separate from the Corporation's marketing contracts. For further information regarding the Corporation's risk management activities, see *"Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts and Transportation and Processing Obligations"* and the Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2019.

**Petroleum and Natural Gas Production and Sales**

During 2019, the Corporation's annual average production was 77,977 boe/d and the products produced and sold by the Corporation were natural gas, light oil, condensate and other NGLs. The following table sets forth the Corporation's annual average production for the year ended December 31, 2019:

| Product | Annual Average Daily Production | % of Annual Average Daily Production |
|---|---|---|
| Natural gas | 364,958 MMcf/d | 78% |
| Light oil | 4,742 bbls/d | 6% |
| Condensate | 5,145 bbls/d | 7% |
| Other NGLs | 7,264 bbls/d | 9% |

Excluding the effects of hedges using financial instruments but including the effects of physical delivery contracts, the Corporation's average realized sales price during 2019 was $2.48/Mcf for natural gas (2018: $2.45/Mcf), $68.29/bbl for light oil (2018: $68.66/bbl), $68.06/bbl for condensate (2018: $77.36) and $13.76/bbl for other NGLs (2018: $22.92/bbl). The following table sets forth the aggregate sales for the Corporation's natural gas, light oil, condensate and other NGLs for the years ended December 31, 2019 and December 31, 2018:

| Product | 2019 Sales(1) | 2018 Sales (1) |
|---|---|---|
| Natural gas | $330,973,288 | $332,978,950 |
| Light oil | $118,182,161 | $122,118,041 |
| Condensate | $127,815,633 | $114,973,198 |
| Other NGLs | $36,487,749 | $51,220,764 |

(1) The amounts set forth in the table above for 2019 and 2018 exclude the effects of hedges using financial instruments but include the effects of physical delivery contracts.

The Corporation's revenues are highly dependent upon the prices that it receives for oil, natural gas, condensate and other NGLs and such prices are closely correlated to the benchmark prices of oil and natural gas. See *"Risk Factors – Prices, Markets and Marketing".*

**Competitive Conditions**

The oil and natural gas industry is highly competitive in all of its phases. The Corporation competes with numerous other entities for land, acquisitions of reserves, access to drilling and service rigs and other equipment, access to transportation and access to skilled technical and operating personnel, among other things. The Corporation's competitors include companies that have more financial resources, staff and facilities than those of the Corporation. See "*Risk Factors – Competition*".

Management believes that the Corporation has a competitive advantage in its focus area of the Peace River Arch area of Alberta based upon the infrastructure and land base it controls. In addition, management believes that it has a competitive advantage based on the experience it has developed on the Montney/Doig Resource Play. The Corporation attempts to enhance its competitive position by operating in areas where it believes its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because such personnel are familiar with the areas.

**Seasonal and Cyclical Factors**

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. In addition, certain oil and natural gas producing properties are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Further, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. Accordingly, seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and a corresponding variability in the Corporation's production. See *"Risk Factors – Climate Change"* and *"Risk Factors – Seasonality"*.

In addition, the Corporation's operational results and financial condition are highly dependent on the prices it receives for its oil and natural gas production. Oil and natural gas prices are subject to large fluctuations and have been depressed during recent years and at times, Canadian oil and natural gas prices have seen significant pricing discounts relative to global benchmark prices. Commodity prices are determined by supply and demand factors, including weather and general economic conditions, as well as egress and processing constraints and conditions in other oil and natural gas regions. Declines in commodity prices adversely affect the Corporation's business and financial condition. See *"Risk Factors – Prices, Markets and Marketing".* The Corporation attempts to mitigate such price risk through closely monitoring the various commodity markets, diversifying its sales portfolio and engaging in risk management activities, as deemed necessary. See *"Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts and Transportation and Processing Obligations".*

**Environmental, Social and Governance**

***Overview***

Birchcliff recognizes the importance of and its responsibility for environmental stewardship and one of the Corporation's primary goals is to create and preserve a safe and environmentally responsible organization. Birchcliff strives to maintain excellence in environmental reporting and to take proactive steps to eliminate or reduce its environmental impact. As an organization that strives for continuous improvement, Birchcliff continues to identify, develop and utilize new technology, systems and processes that will help reduce its environmental footprint and create a safer work environment.

A copy of the Corporation's 2018 Corporate Responsibility Report, which provides additional information regarding Birchcliff's ESG initiatives and activities, including emissions reductions, is available on the Corporation's website at www.birchcliffenergy.com.

***Health, Safety and Environmental Programs***

Birchcliff is committed to continually evolving and improving its health and safety program (the "**H&S Program**") and its environmental management program (the "**EM Program**") and to conducting its activities in a manner that safeguards its employees, contractors and representatives, the public and the environment. Birchcliff's executives, managers, employees and others engaged on its behalf are responsible for upholding the requirements of its H&S and EM Programs.

The objective of Birchcliff's H&S Program is to provide a framework to safeguard its employees, contractors and visitors from personal injury and health and safety hazards. Birchcliff's EM Program focuses on minimizing the environmental impact of its operations while meeting regulatory requirements and corporate standards. The EM Program includes: (i) a suspended well inspection program to support future development or eventual abandonment; (ii) an abandonment and decommissioning program for wells and facilities ready for abandonment; (iii) a surface reclamation program; (iv) a groundwater monitoring program; (v) a spill prevention, response and clean-up program; (vi) a fugitive emission survey and repair program; (vii) an environmental liability assessment program; (viii) a waste management program; (ix) a naturally occurring radioactive materials program; (x) a storage management program; (xi) a facility land vegetation management program; and (xii) a site planning and construction program.

*Training and Emergency Response Plans*

Birchcliff maintains a safe work environment with policies, processes, standards, training, equipment and emergency response procedures that meet or exceed governmental regulations and industry practices. Employees and contractors on Birchcliff's worksites are required to follow all health, safety and environmental rules and procedures outlined in the H&S Program and to participate in pertinent health and safety training.

The Corporation has developed emergency response plans in conjunction with local authorities, emergency services and the communities in which it operates in order to be prepared to effectively respond to an incident should one arise. The Corporation conducts a rigorous emergency response exercise for its staff on an annual basis, as compared to the regulatory requirement of once every three years.

*Alberta Certificate of Recognition (COR) Safety Program*

Birchcliff participates in Alberta's COR Safety Program and has received and maintained a COR certification since 2011. A COR certification demonstrates that the employer's health and safety management system has been evaluated by a certified auditor and meets provincial standards, as established by Alberta Occupational Health and Safety. Maintaining a COR certification requires a commitment to continuous improvement in health, safety and environment management practices, including sound planning and implementation. Birchcliff's H&S Program is audited externally every 3 years by an independent auditor and internally every year by a certified professional.

*Asset Integrity*

Birchcliff works diligently to maintain the safety and integrity of its facility and pipeline infrastructure and maintains two separate integrity programs: a pressure equipment integrity program and a pipeline integrity program. The Corporation's asset integrity group manages its pressure equipment integrity program in compliance with the Alberta Boilers Safety Association requirements and its pipeline integrity program in compliance with AER requirements. These programs are audited internally on an annual basis by a qualified professional and externally on a periodic basis by an independent auditor to evaluate their effectiveness and are updated based on the findings from such audits.

The Corporation's Chief Inspector and asset integrity group make use of databases and associated work tracking systems to ensure that all integrity tasks (inspections, pigging, etc.) are scheduled and completed according to the requirements set forth in the Corporation's programs.

*Environmental Assessments and Audits*

Environmental assessments are undertaken for new projects or when acquiring new properties or facilities in order to identify, assess and minimize environmental risks and operational exposures. The Corporation conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of its policies and programs.

***Community and Stakeholder Relations***

Fostering a strong relationship with the community and its stakeholders is as integral to the success of the Corporation's projects as obtaining the required regulatory approvals. The Corporation believes cooperative, sincere and responsive consultation efforts with stakeholders in the areas in which Birchcliff operates creates a solid foundation for its business. Birchcliff has an experienced team working with local stakeholders to learn their values and priorities and to resolve any issues or concerns that arise.

Birchcliff recognizes the role that communities play in its success and looks for opportunities to give back. The Corporation is a staunch supporter of the community and the business and educational initiatives of the Indigenous communities who live in the areas where Birchcliff operates. Every year, the Corporation participates in a number of community support endeavours in the areas surrounding its field operations and in Calgary. In 2019, the Corporation contributed to a number of local community initiatives that help to elevate and enhance the quality of life at the local level, including minor hockey and other amateur sports, local schools, agricultural societies and fire departments. To date, Birchcliff has helped to raise over $1,000,000 for both STARS Air Ambulance in the Grande Prairie area and the United Way of Calgary. Each year, the Corporation also raises funds for the YWCA. Through Birchcliff's support of Momentum, Calgarians living in poverty learn how to achieve a sustainable livelihood. The Corporation supports the Canadian Cancer Society daffodil campaign and volunteers with Feed the Hungry, providing healthy meals in an atmosphere of dignity and respect. During the holiday season, Birchcliff employees "adopt" a number of families in need and donate gifts, food and decorations to help make the holidays special. The Corporation also fills backpacks with living essentials and gifts for the Mustard Seed and prepares sandwiches for the homeless for the Calgary Drop-In Centre.

Through these activities and numerous others, Birchcliff creates and maintains long-term, positive partnerships and relationships, while promoting employee engagement in the communities in which it operates.

***Governance***

The Board currently consists of five directors, namely A. Jeffery Tonken, Dennis A. Dawson, Debra A. Gerlach, Stacey E. McDonald and James W. Surbey. Mr. Tonken is the Chairman of the Board and Mr. Dawson is the independent lead director. The Board has four committees: the Audit Committee, the Compensation Committee, the Reserves Evaluation Committee and the Nominating Committee. See *"Directors and Officers"*. Additional information on the Corporation's corporate governance practices is contained in the Corporation's information circular for its most recent annual meeting of the holders of Common Shares, which was held on May 16, 2019.

With respect to ESG oversight, the Board has overall responsibility for ESG matters. Each quarter, the Board receives a detailed report from management on things such as the Corporation's safety performance, total recordable incident frequency, asset retirement and reclamation activities and the Corporation's LMR. In addition to the oversight provided by the Board, Birchcliff has established the following committees which are comprised of members of management:

- Greenhouse Gas Regulatory Compliance Committee: The purpose of this committee to help ensure that there is corporate-wide awareness and compliance with the latest provincial and federal GHG legislation requirements which impact Birchcliff's operations.

- ESG Committee: The purpose of this committee is to drive continuous improvement of Birchcliff's ESG-related corporate metrics by: (i) establishing and monitoring ESG-related key performance indicators; (ii) developing and maintaining an effective strategy to communicate ESG-related key performance indicators; and (iii) identifying, prioritizing and directing initiatives to improve ESG key performance indicators within the Corporation.

**Environmental Protection Regulation and Costs**

***General***

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, 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. Compliance with environmental legislation can require significant expenditures and/or result in operational restrictions. A breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. In addition, a breach may result in the suspension or revocation of necessary licences and authorizations and/or the Corporation being subject to interim compliance measures, all of which may restrict the Corporation's ability to conduct operations. Further, the Corporation could be subject to civil liability for pollution damage.

The costs of complying with existing or future environmental legislation or regulations, including those relating to climate change and GHG emissions, may have a material adverse effect on the Corporation's financial condition or results of operations. Future changes in environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability and increased capital expenditures and operating costs. At December 31, 2019, the Corporation has not recorded any material costs and liabilities relating to GHG or environmental protection legislation or any material environmental incidents.

See *"Special Notes to Reader – Forward-Looking Statements", "Industry Conditions"* and *"Risk Factors"*.

***GHG Emissions***

The Corporation's exploration and production facilities and other operations and activities emit GHGs which requires the Corporation to comply with applicable GHG emissions legislation as described under the heading *"Industry Conditions – Climate Change Regulation"*.

With the exception of the Pouce Coupe Gas Plant, the Corporation's facilities were not subject to the CCIR in 2019 as they did not emit more than 100,000 tonnes of GHGs per year. The Pouce Coupe Gas Plant exceeded the 100,000 tonnes of GHGs per year threshold in 2017, 2018 and 2019 and it will be automatically subject to TIER as it exceeds the 100,000 tonnes of GHGs per year threshold. In addition, the Corporation's other facilities have been accepted as an aggregate facility for the purposes of TIER and the TIER Regulation will apply to such facilities for the 2020 year and going forward.

On February 25, 2020, the Corporation received 23,571 emission performance credits under the transitional provisions of the CCIR for the 2018 financial year and it anticipates that it will receive emission performance credits for the 2019 financial year. As the Pouce Coupe Gas Plant and the Corporation's other facilities are currently subject to TIER, such facilities are exempt from paying the federal fuel charge under the GGPPA. See *"Industry Conditions – Climate Change Regulation".*

At the present time, the operational and financial impacts of complying with applicable GHG legislation are not material to the Corporation. The Corporation will continue to monitor and evaluate any developments in the area in order to assess the potential financial and operational implications on the Corporation. Given the multitude of variables that could cause outcomes to change, it is not currently possible to predict the future incremental compliance costs with any certainty. However, given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term, potentially reducing the demand for oil and natural gas resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets.

***Decommissioning Obligations***

As a result of its net ownership interest in oil and natural gas properties and equipment, including well sites, processing facilities and gathering systems, the Corporation incurs decommissioning obligations. The Corporation's decommissioning obligation at December 31, 2019 was $128.0 million, calculated on a discounted fair value basis using a nominal risk-free rate of 1.74% and an inflation rate of 1.33%. Additional information on the Corporation's decommissioning obligations is available in the Corporation's audited annual financial statements for the year ended December 31, 2019.

## Specialized Skill and Knowledge

The Corporation employs individuals with various professional skills and knowledge in the course of pursuing its business plan. In addition, various specialized consultants are available to assist the Corporation in areas where it believes it doesn't need full-time employees. These professional skills include, but are not limited to, geology, geophysics, engineering, financial and business skills, which are generally available in the industry. Drawing on significant experience in the oil and natural gas business, the Corporation believes that its management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; the ability to execute on business development opportunities; and capital markets expertise.

## Employees

The following table sets forth the number of the Corporation's employees at December 31, 2019:

| | Number of Employees |
|---|---|
| Head office employees | 131 |
| Field employees | 74 |

In addition, the Corporation hires skilled contractors to perform drilling operations, well completions and other field service operations. See "*Risk Factors – Reliance on a Skilled Workforce and Key Personnel*".

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

All of the Corporation's reserves are located in the Province of Alberta. Birchcliff retained two independent qualified reserves evaluators, Deloitte and McDaniel, to evaluate and prepare reports on 100% of Birchcliff's light crude oil and medium crude oil, conventional natural gas, shale gas and NGLs reserves. Deloitte evaluated all of Birchcliff's properties other than the Corporation's properties in Gordondale and Progress, representing approximately 80% of the assigned total proved plus probable reserves. McDaniel evaluated the reserves attributable to the Corporation's properties in Gordondale and Progress, representing approximately 20% of the assigned total proved plus probable reserves.

The statement of reserves data and other oil and gas information set forth below is dated March 11, 2020. The effective date of the reserves and future net revenue information provided herein is December 31, 2019, unless otherwise indicated, and the preparation date is February 12, 2020.

Supplemental disclosure of the Corporation's contingent resources data and prospective resources data has been included as Appendix A to this Annual Information Form. The effective date of the resources information provided herein is December 31, 2019, unless otherwise indicated, and the preparation date is March 11, 2020.

The Report on Reserves Data by Deloitte and McDaniel and the Report on Contingent Resources Data and Prospective Resources Data by Deloitte, each in Form 51-101F2, are attached to this Annual Information Form as Appendix B. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 is attached to this Annual Information Form as Appendix C.

### Disclosure of Reserves Data

The reserves data set forth below is based upon the evaluations by Deloitte with an effective date of December 31, 2019 as contained in the report of Deloitte dated February 12, 2020 (the "**Deloitte Reserves Report**") and the evaluation by McDaniel with an effective date of December 31, 2019 as contained in the report of McDaniel dated February 12, 2020 (the "**McDaniel Reserves Report**"), which are contained in the consolidated report of Deloitte dated February 12, 2020 with an effective date of December 31, 2019 (the "**Consolidated Reserves Report**"). Deloitte prepared the Consolidated Reserves Report by consolidating the properties evaluated by Deloitte in the Deloitte Reserves Report with the properties evaluated by McDaniel in the McDaniel Reserves Report. The forecast commodity prices, inflation and exchange rates utilized in the Deloitte Reserves Report, the McDaniel Reserves Report and the Consolidated Reserves Report were computed using the average of forecasts from Deloitte, McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited effective January 1, 2020 (the "**IQRE Price Forecast**"). See *"Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions – Forecast Prices Used in Estimates".*

Deloitte and McDaniel have confirmed to the Reserves Evaluation Committee of the Board that their respective evaluations were prepared in accordance with the standards contained in the COGE Handbook and NI 51-101. In the course of preparing the reserves reports, Birchcliff provided Deloitte and McDaniel with basic information which included land, well and accounting (product prices and operating costs) information, reservoir and geological studies, estimates of on-stream dates for certain properties, contract information, budget forecasts and financial data. Other engineering, geological or economic data required to conduct the evaluations and upon which the reserves reports are based, were obtained from public records, other operators and from Deloitte's and McDaniel's non-confidential files. The extent and character of ownership and accuracy of all factual data supplied to Deloitte and McDaniel was accepted by each of Deloitte and McDaniel as presented. A field inspection and environmental/safety assessment of the properties that were the subject of the reserves evaluations was not conducted.

The net present value of future net revenue attributable to the Corporation's reserves is based on the IQRE Price Forecast and is determined before provision for interest, debt servicing and general and administrative expense and after the deduction of royalties, operating costs, development costs and abandonment and reclamation costs.

The after-tax net present value of the Corporation's oil and natural gas properties reflects the income tax burden on the properties on a stand-alone basis and takes into account the Corporation's existing tax pools. It does not consider the business-entity-level tax situation or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2019 should be consulted for information at the level of the business entity.

**There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGLs reserves and the future net revenue attributed to such reserves. The reserves and associated future net revenue information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil, natural gas and NGLs reserves and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, the timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the economically recoverable oil, natural gas and NGLs reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenue associated with reserves prepared by different engineers, or by the same engineer at different times, may vary. The Corporation's actual production, revenue, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.**

**It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by the Corporation's independent qualified reserves evaluators represent the fair market value of those reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of Birchcliff's oil, natural gas and NGLs reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual oil, natural gas and NGLs reserves may be greater than or less than the estimates provided herein and variances could be material. Estimates 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.**

**NI 51-101 requires a reporting issuer to disclose its reserves in accordance with the product types contained in NI 51-101, which product types include conventional natural gas and shale gas. "Shale gas" as defined in NI 51-101 means natural gas: (i) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals; and (ii) that usually requires the use of hydraulic fracturing to achieve economic production rates. With respect to Birchcliff's natural gas reserves attributable to its Montney/Doig Natural Gas Resource Play, such reserves would most closely fit within the category of shale gas as opposed to conventional natural gas. Birchcliff considers that its natural gas reserves attributable to the Montney/Doig Natural Gas Resource Play to be low permeability gas resources or "tight gas" (as such term is defined in the COGE Handbook). "Shale gas" is the NI 51-101 product type that most closely matches the natural gas from Birchcliff's Montney/Doig Natural Gas Resource Play.**

**As the tables below summarize the data contained in the Consolidated Reserves Report, they may contain slightly different numbers than the Consolidated Reserves Report due to rounding. Also due to rounding, certain columns may not add exactly.**

**The information relating to the Corporation's reserves contains forward-looking statements and information, including information relating to future net revenue, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment and reclamation costs. See *"Special Notes to Reader – Forward-Looking Statements"*.**

For additional information, see *"Presentation of Oil and Gas Reserves and Resources", "Special Notes to Reader"* and *"Risk Factors – Uncertainty of Reserves and Resource Estimates"*.

### *Reserves Summary*

The following table sets forth the Corporation's light crude oil and medium crude oil, conventional natural gas, shale gas and NGLs reserves at December 31, 2019, estimated using the IQRE Price Forecast:

*Summary of Reserves at December 31, 2019*
*(Forecast Prices and Costs)*

| | Light Crude Oil and Medium Crude Oil | | Conventional Natural Gas | | Shale Gas | | NGLs | | Total Boe | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Reserves Category** | ***Gross (Mbbls)*** | ***Net (Mbbls)*** | ***Gross (MMcf)*** | ***Net (MMcf)*** | ***Gross (MMcf)*** | ***Net (MMcf)*** | ***Gross (Mbbls)*** | ***Net (Mbbls)*** | ***Gross (Mboe)*** | ***Net (Mboe)*** |
| Proved | | | | | | | | | | |
| Developed Producing | 9,695.0 | 7,951.6 | 7,814.9 | 7,266.9 | 982,141.3 | 922,927.5 | 32,234.6 | 25,443.1 | 206,922.4 | 188,427.2 |
| Developed Non-Producing | 0.0 | 0.0 | 781.0 | 726.3 | 21,756.0 | 20,362.1 | 650.9 | 547.0 | 4,407.1 | 4,061.8 |
| Undeveloped | 11,358.3 | 9,801.8 | 2,870.5 | 2,624.0 | 2,576,268.7 | 2,414,085.0 | 56,516.9 | 46,590.6 | 497,731.7 | 459,177.2 |
| Total Proved | 21,053.3 | 17,753.5 | 11,466.4 | 10,617.2 | 3,580,166.0 | 3,357,374.6 | 89,402.5 | 72,580.7 | 709,061.2 | 651,666.1 |
| Probable | 12,543.4 | 10,172.4 | 8,348.4 | 7,850.7 | 1,553,306.8 | 1,437,876.2 | 50,314.2 | 39,829.8 | 323,133.5 | 290,956.6 |
| Total Proved Plus Probable | 33,596.8 | 27,925.8 | 19,814.8 | 18,467.9 | 5,133,472.7 | 4,795,250.8 | 139,716.7 | 112,410.5 | 1,032,194.7 | 942,622.8 |

### *Net Present Values of Future Net Revenue*

The following tables set forth the net present values of future net revenue attributable to Birchcliff's reserves at December 31, 2019, estimated using the IQRE Price Forecast, before and after deducting future income tax expenses and calculated at various discount rates:

*Summary of Net Present Values of Future Net Revenue at December 31, 2019*
*(Forecast Prices and Costs)*

| | Before Income Taxes Discounted At (%/year) | | | | | |
|---|---|---|---|---|---|---|
| **Reserves Category** | **0** ***(MM$)*** | **5** ***(MM$)*** | **10** ***(MM$)*** | **15** ***(MM$)*** | **20** ***(MM$)*** | **Unit Value Discounted at 10%/year** ***($/boe)***[(1)] |
| Proved | | | | | | |
| Developed Producing | 3,258.4 | 2,462.2 | 1,938.5 | 1,594.6 | 1,357.2 | 10.29 |
| Developed Non-Producing | 79.2 | 39.8 | 19.5 | 7.7 | 0.3 | 4.80 |
| Undeveloped | 7,044.1 | 3,759.9 | 2,148.9 | 1,271.7 | 755.5 | 4.68 |
| Total Proved | 10,381.7 | 6,261.9 | 4,106.9 | 2,874.0 | 2,113.1 | 6.30 |
| Probable | 5,890.7 | 2,481.5 | 1,207.6 | 654.3 | 383.8 | 4.15 |
| Total Proved Plus Probable | 16,272.4 | 8,743.3 | 5,314.5 | 3,528.3 | 2,496.9 | 5.64 |

(1) Unit values are based on net reserves volumes.

| | After Income Taxes Discounted At (%/year)[(1)] | | | | |
|---|---|---|---|---|---|
| **Reserves Category** | **0** ***(MM$)*** | **5** ***(MM$)*** | **10** ***(MM$)*** | **15** ***(MM$)*** | **20** ***(MM$)*** |
| Proved | | | | | |
| Developed Producing | 2,932.8 | 2,275.4 | 1,824.0 | 1,520.7 | 1,307.6 |
| Developed Non-Producing | 61.5 | 29.7 | 13.2 | 3.6 | (2.5) |
| Undeveloped | 5,415.4 | 2,840.4 | 1,573.8 | 885.3 | 482.3 |
| Total Proved | 8,409.7 | 5,145.5 | 3,411.0 | 2,409.6 | 1,787.3 |
| Probable | 4,528.5 | 1,889.0 | 901.3 | 475.4 | 269.8 |
| Total Proved Plus Probable | 12,938.2 | 7,034.5 | 4,312.3 | 2,885.0 | 2,057.1 |

(1) The after-tax net present value of Birchcliff's oil and natural gas properties reflects the income tax burden on the properties on a stand-alone basis and takes into account Birchcliff's existing tax pools. It does not consider the business-entity-level tax situation or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2019 should be consulted for information at the level of the business entity.

### *Elements of Future Net Revenue*

The following table sets forth the various elements of the Corporation's future net revenue attributable to the Corporation's reserves at December 31, 2019, estimated using the IQRE Price Forecast and calculated without discount:

*Elements of Future Net Revenue (Undiscounted) at December 31, 2019*
*(Forecast Prices and Costs)*

| Reserves Category | Revenue *(MM$)* | Royalties *(MM$)* | Operating Costs *(MM$)* | Develop-ment Costs *(MM$)* | Abandon-ment and Reclamat-ion Costs *(MM$)* | Future Net Revenue Before Future Income Tax Expenses *(MM$)* | Future Income Tax Expenses *(MM$)* | Future Net Revenue After Future Income Tax Expenses *(MM$)*(1) |
|---|---|---|---|---|---|---|---|---|
| Proved | 19,133.4 | 1,600.6 | 3,698.3 | 3,080.6 | 372.3 | 10,381.7 | 1,972.0 | 8,409.7 |
| Proved Plus Probable | 29,970.5 | 2,788.1 | 6,021.8 | 4,418.9 | 469.4 | 16,272.4 | 3,334.2 | 12,938.2 |

(1) The after-tax net present value of Birchcliff's oil and natural gas properties reflects the income tax burden on the properties on a stand-alone basis and takes into account Birchcliff's existing tax pools. It does not consider the business-entity-level tax situation or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2019 should be consulted for information at the level of the business entity.

### *Net Present Values of Future Net Revenue by Product Type*

The following table sets forth by product type, in each case with associated by-products, the future net revenue attributable to the Corporation's reserves at December 31, 2019, estimated using the IQRE Price Forecast, before deducting future income tax expenses and calculated using a 10% discount rate:

*Net Present Values of Future Net Revenue by Product Type at December 31, 2019*
*(Forecast Prices and Costs)*

| Reserves Category | Product Type | Future Net Revenue Before Income Taxes (Discounted at 10%/year) *(MM$)* | Unit Value Before Income Taxes (Discounted at 10%/year) *($/boe)*(1) |
|---|---|---|---|
| Proved | Light Crude Oil and Medium Crude Oil (including solution gas and other by-products) | 873.3 | 10.80 |
| | Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells) | (1.3) | (0.75) |
| | Shale Gas (including by-products) | 3,234.9 | 5.69 |
| | **Total** | **4,106.9** | **6.30** |
| Proved Plus Probable | Light Crude Oil and Medium Crude Oil (including solution gas and other by-products) | 1,266.3 | 9.50 |
| | Conventional Natural Gas (including by-products but excluding solution gas and by-products from oil wells) | 1.7 | 0.54 |
| | Shale Gas (including by-products) | 4,046.4 | 5.02 |
| | **Total** | **5,314.5** | **5.64** |

(1) Unit amounts are derived using net reserves volumes of the product type and associated by-products.

## Pricing Assumptions

### *Forecast Prices Used in Estimates*

The forecast commodity prices, inflation and exchange rates utilized in the Deloitte Reserves Report, the McDaniel Reserves Report and the Consolidated Reserves Report were computed using the average of forecasts from Deloitte, McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited effective January 1, 2020. The following table sets forth the 2019 IQRE Price Forecast:

*IQRE Price Forecast*

| | Crude Oil | | Natural Gas[(1)] | | | NGLs | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | WTI at Cushing Oklahoma *(US$/bbl)* | Edmonton City Gate *(CDN$/bbl)* | Alberta AECO Average Price *(CDN$/Mcf)* | Ontario Dawn Reference Point *(CDN$/Mcf)* | NYMEX Henry Hub *(US$/Mcf)* | Edmonton Ethane *(CDN$/bbl)* | Edmonton Propane *(CDN$/bbl)* | Edmonton Butane *(CDN$/bbl)* | Edmonton Pentanes + Condensate *(CDN$/bbl)* | Currency Exchange Rate *(CDN$/US$)* | Price and Cost Inflation Rates *(%)* |
| 2020 | 60.25 | 71.58 | 2.05 | 3.27 | 2.57 | 6.29 | 24.04 | 37.56 | 74.21 | 0.760 | 0.0 |
| 2021 | 63.11 | 75.33 | 2.32 | 3.62 | 2.79 | 7.17 | 28.75 | 44.41 | 78.15 | 0.768 | 2.0 |
| 2022 | 66.02 | 77.51 | 2.60 | 3.80 | 2.99 | 8.04 | 33.14 | 50.19 | 80.48 | 0.779 | 2.0 |
| 2023 | 67.64 | 79.77 | 2.74 | 3.94 | 3.15 | 8.45 | 34.16 | 51.67 | 82.77 | 0.789 | 2.0 |
| 2024 | 69.16 | 81.60 | 2.82 | 4.05 | 3.22 | 8.73 | 35.00 | 52.88 | 84.66 | 0.786 | 2.0 |
| 2025 | 70.69 | 83.46 | 2.91 | 4.14 | 3.29 | 8.97 | 35.85 | 54.09 | 86.56 | 0.789 | 2.0 |
| 2026 | 72.25 | 85.34 | 2.97 | 4.23 | 3.35 | 9.18 | 36.71 | 55.33 | 88.49 | 0.789 | 2.0 |
| 2027 | 73.77 | 87.19 | 3.03 | 4.31 | 3.43 | 9.38 | 37.55 | 56.53 | 90.40 | 0.789 | 2.0 |
| 2028 | 75.25 | 88.97 | 3.10 | 4.40 | 3.49 | 9.58 | 38.37 | 57.69 | 92.22 | 0.789 | 2.0 |
| 2029 | 76.76 | 90.79 | 3.16 | 4.48 | 3.56 | 9.81 | 39.19 | 58.87 | 94.09 | 0.789 | 2.0 |
| 2030 | 78.29 | 92.61 | 3.24 | 4.57 | 3.64 | 10.01 | 40.03 | 60.05 | 96.00 | 0.789 | 2.0 |
| 2031 | 79.86 | 94.46 | 3.30 | 4.67 | 3.71 | 10.22 | 40.83 | 61.25 | 97.91 | 0.789 | 2.0 |
| 2032 | 81.45 | 96.34 | 3.36 | 4.76 | 3.79 | 10.43 | 41.65 | 62.47 | 99.87 | 0.789 | 2.0 |
| 2033 | 83.08 | 98.27 | 3.44 | 4.85 | 3.86 | 10.62 | 42.48 | 63.72 | 101.87 | 0.789 | 2.0 |
| 2034 | 84.75 | 100.23 | 3.50 | 4.95 | 3.94 | 10.84 | 43.34 | 64.99 | 103.90 | 0.789 | 2.0 |
| 2035 | 86.44 | 102.25 | 3.57 | 5.05 | 4.01 | 11.06 | 44.20 | 66.29 | 105.99 | 0.789 | 2.0 |
| 2036 | 88.17 | 104.29 | 3.65 | 5.15 | 4.10 | 11.28 | 45.08 | 67.63 | 108.11 | 0.789 | 2.0 |
| 2037 | 89.93 | 106.37 | 3.71 | 5.26 | 4.17 | 11.50 | 45.98 | 68.97 | 110.26 | 0.789 | 2.0 |
| 2038 | 91.73 | 108.50 | 3.79 | 5.36 | 4.26 | 11.73 | 46.91 | 70.35 | 112.47 | 0.789 | 2.0 |
| 2039 | 93.57 | 110.66 | 3.86 | 5.47 | 4.34 | 11.98 | 47.84 | 71.76 | 114.71 | 0.789 | 2.0 |
| 2039+ | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% | 0.789 | 2.0 |

(1) 1 Mcf = 1 MMBtu.

These long-term price forecasts are subject to the many uncertainties that affect long-term future forecasts.

***Weighted Average Commodity Prices***

The Corporation's weighted average realized commodity prices for the year ended December 31, 2019, excluding the effects of financial hedges but including the effects of physical delivery contracts, were as follows:

- Light Crude Oil and Medium Crude Oil: $68.29/bbl.
- Shale Gas: $2.48/Mcf (includes conventional natural gas, which represented less than 1% of the Corporation's total corporate natural gas production during 2019).
- NGLs: $36.28/bbl.
    - Condensate: $68.06/bbl.
    - Other NGLs: $13.76/bbl.

**Reconciliation of Changes in Reserves**

The following table sets forth the reconciliation of the Corporation's gross reserves at December 31, 2019 as set forth in the Consolidated Reserves Report, estimated using the IQRE Price Forecast, to the Corporation's gross reserves at December 31, 2018 as set forth in the Prior Consolidated Reserves Report, estimated using Deloitte's forecast price and cost assumptions effective December 31, 2018:

*Reconciliation of Gross Reserves from December 31, 2018 to December 31, 2019*
*(Forecast Prices and Costs)*

| Factors | Light Crude Oil and Medium Crude Oil *(Mbbls)* | Conventional Natural Gas *(MMcf)* | Shale Gas *(MMcf)* | NGLs *(Mbbls)* | Oil Equivalent *(Mboe)* |
|---|---|---|---|---|---|
| **GROSS TOTAL PROVED** | | | | | |
| **Opening balance December 31, 2018** | **20,513.9** | **9,479.7** | **3,588,937.0** | **69,424.1** | **689,674.1** |
| Extensions and Improved Recovery(1) | 2,700.4 | 0.0 | 274,162.5 | 9,974.3 | 58,368.5 |
| Technical Revisions(2) | (494.6) | 957.6 | (90,222.7) | 14,979.7 | (392.4) |
| Discoveries(3) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Acquisitions(4) | 257.4 | 2,805.3 | 11,985.5 | 402.8 | 3,125.3 |
| Dispositions(5) | 0.0 | 0.0 | (29,912.5) | (302.4) | (5,287.8) |
| Economic Factors(6) | (193.1) | (779.2) | (42,571.1) | (546.8) | (7,964.9) |
| Production(7) | (1,730.7) | (996.9) | (132,212.8) | (4,529.3) | (28,461.6) |
| **Closing balance December 31, 2019** | **21,053.3** | **11,466.4** | **3,580,166.0** | **89,402.5** | **709,061.2** |
| **GROSS TOTAL PROBABLE** | | | | | |
| **Opening balance December 31, 2018** | **14,318.3** | **8,546.2** | **1,519,533.0** | **43,397.8** | **312,396.0** |
| Extensions and Improved Recovery(1) | 536.4 | 0.0 | 174,021.8 | 6,914.4 | 36,454.4 |
| Technical Revisions(2) | (2,367.0) | (439.8) | (30,056.7) | 2,762.1 | (4,687.7) |
| Discoveries(3) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Acquisitions(4) | 365.8 | 475.6 | 11,093.7 | 397.8 | 2,691.8 |
| Dispositions(5) | (241.0) | 0.0 | (69,341.2) | (2,462.6) | (14,260.5) |
| Economic Factors(6) | (69.0) | (233.6) | (51,943.8) | (695.2) | (9,460.4) |
| Production(7) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Closing balance December 31, 2019** | **12,543.4** | **8,348.4** | **1,553,306.8** | **50,314.2** | **323,133.5** |
| **GROSS TOTAL PROVED PLUS PROBABLE** | | | | | |
| **Opening balance December 31, 2018** | **34,832.2** | **18,025.9** | **5,108,470.0** | **112,821.9** | **1,002,070.1** |
| Extensions and Improved Recovery(1) | 3,236.8 | 0.0 | 448,184.3 | 16,888.7 | 94,822.9 |
| Technical Revisions(2) | (2,861.6) | 517.8 | (120,279.3) | 17,741.8 | (5,080.1) |
| Discoveries(3) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Acquisitions(4) | 623.2 | 3,280.9 | 23,079.2 | 800.5 | 5,817.1 |
| Dispositions(5) | (241.0) | 0.0 | (99,253.8) | (2,765.0) | (19,548.3) |
| Economic Factors(6) | (262.2) | (1,012.8) | (94,514.9) | (1,241.9) | (17,425.4) |
| Production(7) | (1,730.7) | (996.9) | (132,212.8) | (4,529.3) | (28,461.6) |
| **Closing balance December 31, 2019** | **33,596.8** | **19,814.8** | **5,133,472.7** | **139,716.7** | **1,032,194.7** |

(1) Additions to volumes resulting from capital expenditures for: (i) step-out drilling in previously discovered reservoirs; (ii) infill drilling in previously discovered reservoirs that were not drilled as part of an enhanced recovery scheme; and (iii) the installation of improved recovery schemes.

(2) Positive or negative volume revisions to an estimate resulting from new technical data or revised interpretations on previously assigned volumes, performance and operating costs.

(3) Additions to volumes in reservoirs where no reserves were previously booked.

(4) Positive additions to volume estimates because of purchasing interests in oil and gas properties.

(5) Reductions in volume estimates because of selling all or a portion of an interest in oil and gas properties.

(6) Changes to volumes resulting from different price forecasts, inflation rates and regulatory changes.

(7) Reductions in the volume estimates due to actual production.

Key highlights include the following:

- Extensions and Improved Recovery – Reserves were added due to the wells that were drilled and brought on production pursuant to the Corporation's successful 2019 capital program, which also resulted in the assignment of reserves to potential future drilling locations offsetting those wells.

- Technical Revisions – The technical revisions in all reserves categories for light and medium crude oil were mainly a result of: (i) the performance of the existing producing oil wells; (ii) adjustments to the future well layouts in the development plan; and (iii) future well location adjustments based on offsetting well performance. The technical revisions in all reserves categories for shale gas were mainly a result of: (i) gas shrinkage as a result of higher NGLs extraction in the Pouce Coupe Gas Plant; and (ii) adjustments to the producing oil and gas wells and future oil and gas locations. The technical revisions in all reserves categories for NGLs were a mainly result of: (i) improved performance of the existing C3+ recoveries at Phases V and VI of the Pouce Coupe Gas Plant; (ii) increased condensate from the producing wells and future locations in Pouce Coupe; and (iii) additional C3+ extraction assumed for Phases I to IV of the Pouce Coupe Gas Plant.

- Acquisitions – Changes were the result of the Pouce Coupe Acquisition, which closed on January 3, 2019, as well as various other minor acquisitions Birchcliff completed in the Gordondale and Pouce Coupe areas in 2019.
- Dispositions – Changes were the result of various non-core dispositions Birchcliff completed in 2019.
- Economic Factors – The forecast prices for each product type were lower in the IQRE Price Forecast than the price forecast used in the Prior Consolidated Reserves Report, which resulted in the economic limit at the end of a well's life being achieved earlier and therefore a reduction of the reserves volumes in all reserves categories. The reduced price forecast also resulted in the loss of reserves for 4 gross (2.5 net) proved undeveloped future natural gas locations and 11 gross (6.6 net) probable future natural gas locations, primarily in Elmworth, that did not generate a positive net present value at a 10% discount rate.

**Additional Information Relating to Reserves Data**

***Undeveloped Reserves***

Undeveloped reserves are attributed by Deloitte and McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Approximately 100% of the Corporation's proved undeveloped reserves are attributed to the Montney/Doig Resource Play concentrated in the Corporation's key operating areas in Pouce Coupe and Gordondale. The Consolidated Reserves Report has attributed proved undeveloped reserves to each potential future horizontal drilling location that is proximal to an existing well to which Deloitte and McDaniel attributed proved developed reserves. Deloitte and McDaniel estimated such proved undeveloped reserves using forecast production rates that were based on a statistical analysis of production rates of existing wells operated by the Corporation or others on the Montney/Doig Resource Play in the regional area. If the development timeline went beyond five years of a major plant expansion, then these proximal locations were classified as probable undeveloped reserves.

The following table sets forth for each product type the volumes of proved undeveloped reserves and probable undeveloped reserves that were first attributed as reserves in each of the three most recent financial years:

*Undeveloped Reserves*

| | **Proved Undeveloped Reserves** | | | | **Probable Undeveloped Reserves** | | | |
|---|---|---|---|---|---|---|---|---|
| **Year of first attribution** | **Light Crude Oil and Medium Crude Oil *(Mbbls)*** | **Conventional Natural Gas *(MMcf)*** | **Shale Gas *(MMcf)*** | **NGLs *(Mbbls)*** | **Light Crude Oil and Medium Crude Oil *(Mbbls)*** | **Conventional Natural Gas *(MMcf)*** | **Shale Gas *(MMcf)*** | **NGLs *(Mbbls)*** |
| 2019 | 2,298 | 0 | 209,097 | 7,384 | 501 | 0 | 178,387 | 7,080 |
| 2018 | 4,909 | 0 | 161,072 | 10,345 | 3,742 | 0 | 147,460 | 7,084 |
| 2017 | 3,922 | 0 | 603,102 | 10,507 | 6,147 | 0 | 219,167 | 10,345 |

The Corporation has a large inventory of development opportunities in its portfolio and its capital spending activities are prioritized to optimize development plans, achieve strategic goals and maximize shareholder value.

As at December 31, 2019, undeveloped reserves represented approximately 70% of the Corporation's total proved reserves and approximately 76% of the Corporation's total proved plus probable reserves. Birchcliff is focused on developing these undeveloped reserves in its core areas of Pouce Coupe and Gordondale where the vast majority of the undeveloped reserves are assigned and available processing capacity exists and future processing capacity expansions are forecast to take place. In the Consolidated Reserves Report, the Corporation's independent qualified reserves evaluators forecast that 45 net wells and 57.6 net wells would be drilled in 2020 and 2021, respectively.

The Corporation's Revised 2020 Capital Program contemplates the drilling of 28 (28.0 net) horizontal wells during 2020 and the bringing on production of 34 (34.0 net) wells. Birchcliff anticipates that drilling activities in 2020 and 2021 will utilize available capacity at the Pouce Coupe Gas Plant (currently 340 MMcf/d) and the Gordondale Gas Plant (currently 120 MMcf/d), as well as capacity as it becomes available from third-party processors. Over the ensuing years, the Corporation expects that it will continue to develop its proved undeveloped reserves on the Montney/Doig Resource Play as processing capacity at the Pouce Coupe Gas Plant is forecast to be expanded to 660 MMcf/d.

Given the Corporation's large, contiguous and concentrated land base, significant inventory of potential future drilling locations, required timing of facility and infrastructure construction and the executional pace of the Corporation's drilling programs, the timing of the development of the Corporation's proved undeveloped and probable undeveloped reserves extends past two years. Approximately 19% of the proved undeveloped locations are forecast to be drilled within the first two years. The remainder of the proved undeveloped locations are forecast to be drilled in the next five years with the addition of the forecast expansion of the Pouce Coupe Gas Plant and the ongoing resource play development in Pouce Coupe and Gordondale. Approximately 3% of the probable undeveloped locations are forecast to be drilled within the first two years. The remainder of the probable undeveloped locations are forecast to be drilled in the next eight years with the addition of the forecast expansion of the Pouce Coupe Gas Plant and the ongoing resource play development in Pouce Coupe and Gordondale. All of the Corporation's proved and probable undeveloped reserves are forecast to be drilled in the time frames recommended by the COGE Handbook.

The pace of development of the Corporation's proved and probable undeveloped reserves is influenced by many factors, including the outcomes of the yearly drilling and reservoir evaluations, the price for oil and natural gas, and a variety of economic factors and conditions. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

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

The process of estimating reserves is 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 reserves estimates contained in this Annual Information Form are based on production forecasts, prices and economic conditions at December 31, 2019. Factors and assumptions that affect these reserves estimates include, but are not limited to, historical production from the properties, production rates, ultimate reserves recovery, the timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results.

As circumstances change and additional data becomes available, reserves 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 governmental restrictions.

Although every reasonable effort is made to ensure that reserves estimates are accurate, reserves estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserves estimates can arise from changes in year-end oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative.

Changes in future commodity prices relative to the forecasts described above under *'Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions''* could have a negative impact on the Corporation's reserves, and in particular on the development of undeveloped reserves, unless future development costs are adjusted in parallel. The Corporation has a significant amount of proved and probable undeveloped reserves. At the forecast prices and costs used in the Consolidated Reserves Report, these development activities are expected to be economic. However, should oil and natural gas prices decrease materially, these activities may not be economic and the Corporation may defer their implementation. This deferral could result in proved reserves being reclassified as probable reserves and probable reserves being reclassified as contingent resources. In addition, reserves can be significantly affected by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes, abandonment and reclamation costs and well performance that is beyond the Corporation's control and which could affect the Corporation's development decisions.

Other than the foregoing and the factors disclosed or described herein, the Corporation does not anticipate any other significant economic factors or other significant uncertainties which may affect any particular components of its reserves data. See also *"Risk Factors – Uncertainty of Reserves and Resource Estimates"*.

***Abandonment and Reclamation Costs***

In connection with its operations, the Corporation will incur abandonment and reclamation costs for surface leases, wells, gathering systems, pipelines and facilities. Abandonment and reclamation costs have been estimated by Deloitte and McDaniel in their respective evaluations and include abandonment, decommissioning and reclamation costs for all oil and natural gas assets, including all wells, gathering systems, pipelines, facilities and surface land development. Well abandonment and reclamation costs used by Deloitte and McDaniel were provided by Birchcliff and were not independently evaluated. Such costs were estimated by Birchcliff and were generally greater than the average costs for the Corporation's regional reclamation cost area set forth in AER Directive 011: *Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs*.

In estimating the future net revenue disclosed in this Annual Information Form, the Consolidated Reserves Report deducted $469.4 million (undiscounted) and $40.2 million (10% discount) for abandonment and reclamation costs for all wells, gathering systems, pipelines and surface land development that have been attributed proved and probable reserves. There are no unusually significant abandonment and reclamation costs associated with the Corporation's properties.

See Note 8 – *Decommissioning Obligations* to the Corporation's audited annual financial statements for the year ended December 31, 2019 and *"Description of the Business – Environmental Protection Regulation and Costs – Decommissioning Obligations"*.

***Future Development Costs***

Future development costs reflect the independent reserves evaluator's best estimate of what it will cost to bring the proved and proved plus probable reserves on production. Changes in forecast future development costs occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates. The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserves categories noted below:

*Future Development Costs*
*(Forecast Prices and Costs)*

| | **Proved** ***(MM$)*** | **Proved Plus Probable** ***(MM$)*** |
|---|---|---|
| 2020 | 322.5 | 322.5 |
| 2021 | 411.8 | 475.4 |
| 2022 | 555.8 | 611.9 |
| 2023 | 775.8 | 818.0 |
| 2024 | 405.0 | 508.3 |
| Thereafter | 609.7 | 1,682.8 |
| **Total undiscounted** | **3,080.6** | **4,418.9** |

The Corporation expects to be able to fund the development costs required in the future primarily from internally generated cash flow, as well as its existing credit facilities. Future development costs may also be funded through the proceeds realized from property dispositions and debt or equity financings. Planned activity levels vary each year due to factors such as capital availability, commodity prices, processing and transportation capacity and regulatory processes.

There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the Consolidated Reserves Report. Failure to develop those reserves would have a negative impact on the future production and future net revenue estimated by the Corporation's independent qualified reserves evaluators and could result in negative revisions to reserves.

Interest and other costs of external funding are not included in the estimates of reserves and future net revenue set forth herein and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation currently does not anticipate that interest or other funding costs would make the development of any of these properties uneconomic.

## Other Oil and Gas Information

### *Oil and Gas Properties and Wells*

The Corporation's important properties and facilities are described under the heading *"Description of the Business".* All of the Corporation's properties are located in Alberta and are onshore. None of the Corporation's important properties or facilities are subject to any material statutory or other mandatory relinquishments, surrenders, back-ins or changes in ownership.

The following table sets forth the Corporation's producing and non-producing oil and natural gas wells at December 31, 2019:

*Producing and Non-Producing Wells at December 31, 2019*[(1)]

| | Oil Wells | | | | Natural Gas Wells | | | |
|---|---|---|---|---|---|---|---|---|
| | Producing | | Non-producing | | Producing | | Non-producing | |
| | ***Gross*** | ***Net*** | ***Gross*** | ***Net*** | ***Gross*** | ***Net*** | ***Gross*** | ***Net*** |
| Alberta | 135 | 116.3 | 42 | 24.7 | 433 | 399.1 | 197 | 147.2 |

(1) Does not include water injection wells, service wells, capped wells and wells that have not been categorized as either oil wells or natural gas wells.

The Corporation has no properties to which reserves have been attributed which are capable of production but not producing except as described herein. At December 31, 2019, the Corporation had 4 (4.0 net) wells categorized as proved developed non-producing in the Consolidated Reserves Report. These wells have been non-producing for periods ranging from 17 months to eight years. All of these wells are near pipelines and processing facilities and consist of vertical and horizontal wells. Birchcliff expects 1 of these wells to be classified as proved developed producing at the end of 2020. Of the remaining 3 wells, 1 is expected to be brought on production in 2022, 1 in 2025 and 1 in 2026.

### *Undeveloped Lands*

The following table sets forth the gross and net acres of undeveloped lands held by the Corporation as at December 31, 2019:

*Undeveloped Lands*

| | Gross Acres | Net Acres |
|---|---|---|
| Alberta | 220,629.4 | 193,049.6 |

When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. When there are multiple discontinuous rights in a single lease, the acreage is reported only once.

The rights to explore, develop and exploit with respect to 17,120.0 (16,736.0 net) acres of such undeveloped lands are expected to expire within one year of the date of this Annual Information Form. Such expiries will not materially affect the reserves attributable to Birchcliff's lands. The Corporation has no material work commitments on such undeveloped lands.

***Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves***

There are several economic factors and significant uncertainties that affect the anticipated development of the Corporation's properties to which no reserves have been attributed. The Corporation will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil, natural gas and NGLs from these properties in the future. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, that the terms will be acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain opportunities, reduce its pace of development or terminate its operations on such properties. An inability of the Corporation to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Corporation's ability to execute its business strategy to develop its prospects.

The significant economic factors that affect the Corporation's future development of its lands to which no reserves have been attributed are:

(i) future commodity prices for oil and natural gas (and the Corporation's outlook relating to such prices);

(ii) the future capital costs of drilling, completing, tying in and equipping the wells necessary to develop such lands at the relevant times;

(iii) the future costs of operating wells at the relevant times; and

(iv) the levels of royalties applicable to productions from such lands.

The significant uncertainties that affect the Corporation's development of its lands to which no reserves have been attributed are:

(i) the ability of the Corporation to obtain the capital necessary to fund the development of such lands at the relevant times;

(ii) the future drilling and completion results the Corporation achieves in its development activities (e.g. with respect to the development of particular intervals or geographic areas, the uncertainty would be whether the initial drilling and completion results are sufficient to justify the development of such interval or geographic area);

(iii) drilling and completion results achieved by others on lands in proximity to the Corporation's lands;

(iv) transportation and processing infrastructure becoming available in a timeline consistent with proposed development plans;

(v) the availability of regulatory approvals for development of the lands and the necessary infrastructure; and

(vi) governmental actions and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities.

All of these uncertainties have the potential to delay the development of such lands. On the other hand, uncertainty as to the timing and nature of the evolution of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to the development of such lands.

There are no unusually significant abandonment and reclamation costs associated with the Corporation's properties to which no reserves have been attributed.

For a description of the Corporation's contingent and prospective resources, including a discussion of the development plans for the Corporation's development pending contingent resource projects and the contingencies which prevent the Corporation's contingent resources from being classified as reserves, see Appendix A to this Annual Information Form. See also "*Risk Factors – Uncertainty of Reserves and Resource Estimates*".

### *Forward Contracts and Transportation and Processing Obligations*

The Corporation has used and may continue to use various types of derivative financial instruments and physical delivery contracts to manage the risks related to fluctuating commodity prices. Subject to compliance with the Credit Facilities, the Board has authorized the Corporation to execute a risk management strategy whereby Birchcliff is authorized to enter into agreements and financial or physical transactions with one or more counterparties from time to time that are intended to reduce the risk to the Corporation from volatility in future commodity prices, foreign exchange rates and/or interest rates. A summary of the Corporation's risk management contracts can be found in Note 18 – *Risk Management* to the Corporation's audited annual financial statements for the year ended December 31, 2019 and under the heading *"Discussion of Operations – Risk Management"* in the Corporation's management's discussion and analysis for the year ended December 31, 2019. Other than as disclosed in the Corporation's audited annual financial statements for the year ended December 31, 2019, the Corporation is not bound by any agreement (including any transportation agreement), directly or through an aggregator, under which it is precluded from fully realizing, or may be protected from the full effect of, future market prices for crude oil or natural gas. See *''Risk Factors – Hedging''* for additional information on the risks and uncertainties relating to the Corporation's hedging activities.

As part of normal business operations, the Corporation enters into firm service obligations for the transportation and processing (as applicable) of its natural gas, oil and NGLs production volumes in order to secure access to the infrastructure necessary to transport and process such volumes. Accordingly, the Corporation renews, amends or enters into new firm service agreements from time to time, having consideration for its forecast capacity requirements and current and future growth plans, capacity constraints and its expectations for future transportation and processing costs.

With respect to transportation, the Corporation believes that to move its production to market over the short and long-term, it should generally secure firm transportation sufficient for its current and future growth plans. The Corporation has transportation commitments that exceed forecast production volumes of the Corporation's proved reserves in the Consolidated Reserves Report for the period from January 1, 2020 to December 31, 2021 by an average of approximately 132.3 MMcf/d. These excess commitments relate to the Corporation's firm service commitments on the NGTL System (see *"Description of the Business – Transportation Arrangements"*). The estimated cost of the excess transportation equates to an undiscounted total cost of approximately $27.0 million over the period (2020: $13.9 million; 2021: $13.2 million). Birchcliff strives to mitigate excess NGTL transportation costs through marketing initiatives to other parties that do not have firm transportation to move natural gas volumes on the NGTL System.

With respect to processing, the Corporation has fractionation processing commitments that exceed forecast production volumes of the Corporation's proved reserves in the Consolidated Reserves Report for the period from January 1, 2020 to March 31, 2026 by an average of 1,798 bbls/d. These excess commitments relate to the Corporation's fractionation commitments for NGLs at the Pembina Facility (see *"Description of the Business – Processing Arrangements"*). The estimated cost of the excess fractionation equates to an undiscounted total cost of approximately $18.4 million over the period. Birchcliff strives to mitigate excess NGLs fractionation costs through strategic marketing with third parties and other producers that are short fractionation capacity.

### *Tax Horizon*

The Corporation was not required to pay any cash income taxes for the year ended December 31, 2019. The Corporation estimates that based on its current expenditure plans and the current price environment, no income taxes will become payable on the Corporation's income for the financial year ended December 31, 2020. As at December 31, 2019, the Corporation had accumulated tax pools and loss carry forwards of approximately $2.1 billion which can be used to offset taxable income in future years. Based on anticipated capital investment, which further augments the tax pools, it is likely that the Corporation will not become taxable within the next five years as long as commodity prices remain consistent with today's environment.

### *Costs Incurred*

The following table sets forth the Corporation's property acquisition costs for proved and unproved properties, exploration costs and development costs for the year ended December 31, 2019:

*2019 Acquisition, Exploration and Development Costs*

| Acquisition Costs | | | |
|---|---|---|---|
| **Proved Properties** ***(MM$)*** | **Unproved Properties** ***(MM$)*** | **Exploration Costs** ***(MM$)*** | **Development Costs** ***(MM$)*** |
| 41.4 | 0.0 | 9.7 | 246.7 |

### *Exploration and Development Activities*

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

*2019 Exploration and Development Activities*

| | **Exploratory Wells**[(1)] | | **Development Wells**[(1)] | | **Total**[(1)] | |
|---|---|---|---|---|---|---|
| | ***Gross*** | ***Net*** | ***Gross*** | ***Net*** | ***Gross*** | ***Net*** |
| Oil wells | 0.0 | 0.0 | 14.0 | 14.0 | 14.0 | 14.0 |
| Natural gas wells | 0.0 | 0.0 | 16.0 | 16.0 | 16.0 | 16.0 |
| Service wells | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Stratigraphic test wells | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Dry holes | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total** | **0.0** | **0.0** | **30.0** | **30.0** | **30.0** | **30.0** |

(1) Number of wells based on rig release dates.

The Corporation's most important current and likely exploration and development activities for 2020 will focus on the drilling of wells on the Montney/Doig Resource Play, as well as completing the Inlet Liquids-Handling Facility at the Pouce Coupe Gas Plant. The Revised 2020 Capital Program contemplates the drilling of 28 (28.0 net) wells and the bringing on production of 34 (34.0 net) wells in 2020. See *"General Development of the Business – Recent Developments"* for further information regarding the Corporation's Revised 2020 Capital Program.

### *Production Estimates*

The following table sets forth the volume of production estimated for the year ending December 31, 2020 which is reflected in the estimates of gross proved reserves and gross probable reserves disclosed in the tables above under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data"*:

*2020 Production Volume Estimates*

| | **Light Crude Oil and Medium Crude Oil** ***(Mbbls)*** | **Shale Gas** ***(MMcf)***[(1)] | **NGLs** ***(Mbbls)*** | **Oil Equivalent** ***(Mboe)*** |
|---|---|---|---|---|
| Gross Proved | 2,144.7 | 142,010.0 | 5,337.4 | 31,150.4 |
| Gross Probable | 88.9 | 1,136.1 | 68.6 | 346.9 |

(1) Conventional natural gas volumes have been included in the shale gas volumes as conventional natural gas volumes represented less than 1% of the volume estimates for 2020.

The following table sets forth the estimated production volumes for the fields that account for more than 20% of the estimated production volumes for the year ending December 31, 2020:

*2020 Production Volume Estimates for Important Fields*

| **Field Name** | **Gross Proved Reserves** ***(Mboe)*** | **Gross Probable Reserves** ***(Mboe)*** |
|---|---|---|
| Pouce Coupe | 19,724.3 | 65.2 |
| Gordondale | 11,231.4 | 280.2 |

***Production History***

The following table sets forth, by product type, the average daily production, the average prices received, the royalties paid, the production costs incurred, the transportation and other costs incurred and the resulting netback for the periods indicated:

*2019 Average Daily Production, Prices Received, Royalties, Costs and Resulting Netback*

| | **Three months ended** | | | | **Year ended** |
|---|---|---|---|---|---|
| | **March 31, 2019** | **June 30, 2019** | **September 30, 2019** | **December 31, 2019** | **December 31, 2019** |
| **Average Daily Production**[(1)] | | | | | |
| Light Crude Oil and Medium Crude Oil *(bbls/d)* | 4,800 | 4,853 | 4,882 | 4,435 | 4,742 |
| Shale Gas *(Mcf/d)*[(2)] | 353,548 | 367,033 | 374,180 | 364,847 | 364,958 |
| NGLs *(bbls/d)* | 11,159 | 12,428 | 13,303 | 12,720 | 12,409 |
| Combined *(boe/d)* | 74,884 | 78,453 | 80,548 | 77,962 | 77,977 |
| **Average Prices Received**[(3)] | | | | | |
| Light Crude Oil and Medium Crude Oil *($/bbl)* | 66.08 | 72.25 | 67.15 | 67.58 | 68.29 |
| Shale Gas *($/Mcf)*[(2)] | 3.55 | 1.95 | 1.71 | 2.81 | 2.48 |
| NGLs *($/bbl)* | 36.61 | 37.95 | 34.01 | 36.74 | 36.28 |
| Combined *($/boe)* | 26.45 | 19.59 | 17.62 | 22.97 | 21.55 |
| **Royalties Paid** | | | | | |
| Light Crude Oil and Medium Crude Oil *($/bbl)* | 6.80 | 10.76 | 9.21 | 8.69 | 8.88 |
| Shale Gas *($/Mcf)*[(2)(4)] | 0.01 | (0.16) | (0.07) | 0.00 | (0.06) |
| NGLs *($/bbl)* | 4.81 | 5.37 | 3.33 | 4.05 | 4.35 |
| Combined *($/boe)* | 1.22 | 0.75 | 0.76 | 1.15 | 0.96 |
| **Production Costs**[(5)] | | | | | |
| Light Crude Oil and Medium Crude Oil *($/bbl)* | 5.29 | 5.49 | 4.90 | 4.62 | 5.08 |
| Shale Gas *($/Mcf)*[(2)] | 0.51 | 0.48 | 0.40 | 0.47 | 0.46 |
| NGLs *($/bbl)* | 4.28 | 3.84 | 3.48 | 3.66 | 3.81 |
| Combined *($/boe)* | 3.40 | 3.17 | 2.75 | 3.06 | 3.09 |
| **Transportation and Other Costs**[(6)] | | | | | |
| Light Crude Oil and Medium Crude Oil *($/bbl)* | 3.91 | 4.73 | 4.98 | 4.73 | 4.59 |
| Shale Gas *($/Mcf)*[(2)] | 0.75 | 0.70 | 0.68 | 0.76 | 0.72 |
| NGLs *($/bbl)* | 5.48 | 4.47 | 5.38 | 4.17 | 4.86 |
| Combined *($/boe)* | 4.61 | 4.29 | 4.34 | 4.51 | 4.44 |
| **Resulting Netback**[(6)] | | | | | |
| Light Crude Oil and Medium Crude Oil *($/bbl)* | 50.09 | 51.26 | 48.06 | 49.54 | 49.74 |
| Shale Gas *($/Mcf)*[(2)] | 2.27 | 0.93 | 0.70 | 1.58 | 1.36 |
| NGLs *($/bbl)* | 22.04 | 24.27 | 21.82 | 24.86 | 23.25 |
| Combined *($/boe)* | 17.22 | 11.38 | 9.77 | 14.25 | 13.07 |

(1) Before deduction of royalties and without including any royalty interests.

(2) Conventional natural gas volumes have been included in the shale gas volumes as conventional natural gas volumes represented less than 1% of the Corporation's total corporate natural gas production in 2019 and are therefore not considered material.

(3) Excludes the effects of hedges using financial instruments but includes the effects of physical delivery contracts.

(4) Includes the effects of prior period gas cost allowance credits received by the Corporation.

(5) Production costs are comprised of direct costs incurred to operate wells that produce any one or more of the product types that are shown. Costs have been allocated to product production on a pro rata basis.

(6) Transportation and other costs and netback do not have any standardized meanings and should not be used for the purposes of drawing comparisons between the Corporation and other companies. For additional information, see *"Non-GAAP Measures"* in this Annual Information Form and in the Corporation's management's discussion and analysis for the year ended December 31, 2019.

The following table sets forth, by product type, the Corporation's average daily production volumes for the year ended December 31, 2019 for each field comprising more than 10% of the Corporation's total production:

*2019 Production Volumes By Field*

| | **Light Crude Oil and Medium Crude Oil** *(bbls/d)* | **Shale Gas** *(Mcf/d)*[(1)] | **NGLs** *(bbls/d)* | **Oil Equivalent** *(boe/d)* |
|---|---|---|---|---|
| Pouce Coupe | 0 | 274,009 | 4,949 | 50,616 |
| Gordondale | 4,686 | 90,947 | 7,513 | 27,357 |

(1) Conventional natural gas volumes have been included in the shale gas volumes as conventional natural gas volumes represented less than 1% of the Corporation's total corporate natural gas production in 2019 and are therefore not considered material.

## INDUSTRY CONDITIONS

Companies carrying on business in the oil and natural gas industry in Canada are subject to extensive controls and regulations imposed through the legislation of the Federal Government and the provincial governments where such companies have assets or operations. While such regulations and controls do not affect the Corporation's business 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 controls and regulations carefully. Although governmental legislation is a matter of public record, the Corporation is unable to predict what additional legislation or amendments to existing legislation governments may enact in the future.

The Corporation holds interests in oil and natural gas properties, along with related assets, in the Province of Alberta. 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 oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations of, and access to, 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) the storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, the Corporation 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 oil and natural gas industry in Western Canada, and particularly in the Province of Alberta.

### Pricing and Marketing in Canada

#### *Crude Oil*

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

#### *Natural Gas*

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

***NGLs***

The price of condensate 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 price depends, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, supply/demand balance, the length of the contract term and other contractual terms.

**Exports from Canada**

As discussed in further detail below under the heading *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal"*, Bill C-69 came into force on August 28, 2019, replacing, among other things, the *National Energy Board Act* (Canada) (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and the National Energy Board (the "**NEB**") with the Canadian Energy Regulator (the "**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 NGLs 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 natural 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 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 20 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.

As discussed in further 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 changed the federal approval process with the enactment of the CERA, the *Impact Assessment Act* (Canada) (the "**IAA**") and the creation of the CER. The stated purpose of this regulatory change is 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 will conduct its regulatory functions as 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 may arise in connection with 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 the relevant environmental review processes. In addition, export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals from several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian 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, especially through the Midwest United States and export shipping terminals on the west coast of Canada and the Gulf Coast, could help to alleviate the 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 economic and socio-political factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of many pipeline projects.

With respect to the current state of the transportation and export 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 some 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 that quashed 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 an agreement with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four applications for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (British Columbia) to impose a permitting requirement on carriers of heavy crude oil 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.

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company 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 km 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 km long segment of the pipeline that will cross the Canada-United States Border remains dependent on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

***Marine Tankers***

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act* (Canada), which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tonnes 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/d 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 would 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, 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 have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

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

Additionally, while a number of LNG export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the proponents of the LNG Canada LNG 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, British Columbia, via the Coastal GasLink pipeline, which will be built and operated by TC Energy (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. On May 1, 2019, the British Columbia Oil and Gas 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 delayed pre-construction and construction activities of the CGL Pipeline. Coastal Gaslink Pipeline Ltd. ("**CGL**") obtained an injunction on December 31, 2019. 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. This licence remains subject to Cabinet approval and Chevron Canada Limited has indicated that it is interested in selling its 50% interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The British Columbia Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. continues to make its way through the federal impact assessment process for the construction and operation of an 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 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 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.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 MMbbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for December 2019, January 2020 and February 2020 was set at 3.81 MMbbls/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 has not been subject to any curtailment orders.

## NAFTA and Other Trade Agreements

### *NAFTA and USMCA*

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

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

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply lowered the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer may be reduced while Canadian crude oil prices are depressed. It is possible that the USMCA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

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

***Other Trade Agreements***

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries, while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union have 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 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 oil and natural gas located in Western Canada. According to Alberta Energy, the Crown owns approximately 81% of the Province of Alberta's mineral rights. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where oil and natural gas companies bid for leases to explore for and produce 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.

The Province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licences issued after January 1, 2009. Shallow reversion will occur at the conclusion of the primary term of the lease or intermediate term of the licence.

To develop oil and natural gas resources, it is necessary for the mineral rights holder 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.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Alberta. According to Alberta Energy, approximately 19% of the mineral rights in Alberta are owned by private freehold owners and other non-Crown entities, as well as the Federal Government as discussed in further detail below. The rights to explore for and produce oil and natural gas with private freehold owners 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 oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the 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 the exploration and production of 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* (Canada) (the "**IOGA**") and the *Indian Oil and Gas Regulations*, *1995*. 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.

**Royalties and Incentives**

***General***

Each province has legislation and regulations that govern royalties and production rates. The royalty regime in a given province is a significant factor in the profitability of 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 freehold mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of Crown 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 the Western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and 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 the recovery of oil, natural gas and NGLs.

In addition, the Federal Government may from time to time provide incentives to the oil and natural gas industry. In November 2018, the Federal Government announced its plans to implement an accelerated investment incentive, aimed to provide crude oil and natural gas businesses with eligible CDE and COGPE with a first-year deduction of one and a half times the deduction that is otherwise available for CDE and COGPE. The definitions of "accelerated CDE" and "accelerated COGPE", as amended in November 2018, allow oil and gas businesses to claim an additional 15% deduction for new CDE, and an additional 5% deduction for new COGPE for taxation years that end before 2024 if such CDE or COGPE was incurred after November 20, 2018. The acceleration is reduced to 7.5% for new CDE and 2.5% for new COGPE for taxation years that begin after 2023 and end before 2028. Successored expenses, and costs in respect of Canadian resource properties not acquired at arms' length, will not qualify for treatment as accelerated CDE or accelerated COGPE.

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 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.

***The Royalty Framework in Alberta***

*Crown Royalties*

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 "**Previous 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 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 revenue 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 revenue of between 5% and 40% for 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 Previous 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, to 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.

The Previous Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Previous 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 Previous Framework range from a base rate of 5% to a cap of 36%. The Previous 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 Previous Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane.

*Freehold and Other Types of Non-Crown Royalties*

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

IOGC is responsible for managing and regulating the oil and natural gas resources located on Indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the oil and natural gas agreements between Indigenous groups and oil and natural gas companies, as well as collecting royalty revenue on behalf of Indigenous groups and depositing the revenue in their trust accounts. While certain standards exist, the exact terms and conditions of each 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 terms.

***Incentives***

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage 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.

**Rental Payments and Freehold Mineral Taxes**

Currently, producers of 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 oil and natural gas produced.

In addition to the royalties payable to the mineral owners (or to other royalty holders, if applicable), producers of 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 oil and natural gas production from lands where the Crown does not hold the mineral rights. 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 revenue 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.

**Regulatory Authorities and Environmental Regulation**

***General***

The Canadian 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 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 legislation for air pollution and GHG emissions, including $CO_2e$, may impose further requirements on operators and other companies in the 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 IAA came into force and the NEB Act and the *Canadian Environmental Assessment Act, 2012* (Canada) (the "**CEAA**") were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency (the "**CEA Agency**").

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

Designated projects will require an impact assessment as part of their regulatory review. The impact assessment includes expanded criteria that a 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 interprovincial or international pipelines that require more than 75 km 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 and there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

On May 12, 2017, the Federal Government introduced Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the *Oil Tanker Moratorium Act* (Canada) 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* (Alberta) and a number of related legislation, including the OGCA, the *Oil Sands Conservation Act* (Alberta), the *Pipeline Act* (Alberta) and the *Environmental Protection and Enhancement Act* (Alberta). 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 Alberta Energy's responsibility for mineral tenure.

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 Alberta Environment and Parks, Alberta 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.

<u>*Liability Management Rating Program*</u>

In 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 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 Program**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP Program 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.

Complementing the AB LMR Program, the 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 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 Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

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 while dealing with the company's valuable assets for the benefit of the company's creditors without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In response to Redwater's trajectory through the Court, the AER introduced amendments to its liability management framework. The AER amended Directive 067: *Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licence eligibility to operate wells and facilities. The changes to Directive 067 include requiring additional information at the time of application, increased discretion regarding the rejection of applications and requirements for keeping corporate information up to date. Directive 067 also now requires an applicant to provide information regarding the corporate structure of the applicant, whether there are any current regulatory proceedings or outstanding non-compliances, information regarding the applicant's shareholders and whether any directors or officers of the applicant have been directors or officers of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under Directive 013: *Suspension Requirements for Wells*. The IWCP applies to all inactive wells that are non-compliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive non-compliant 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 by 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 non-compliant 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 non-compliant 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 its subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal crude oil and natural gas infrastructure, the AER announced a voluntary area-based closure program in 2018 (the "**ABC Program**"). The ABC Program is designed to reduce the cost of abandonment and reclamation operations through 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.

**Climate Change Regulation**

***Federal***

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of March 4, 2020, 189 of the 197 parties to the convention have ratified the Paris Agreement. Canada ratified the Paris Agreement on October 5, 2016. 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 "**Pan-Canadian Framework**"). The Pan-Canadian 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* (Canada) (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

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

The Federal Government has also enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999* (Canada), 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.

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 oil and natural gas industry and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that 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.

Finally, 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.

***Alberta***

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (Alberta) (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* (Alberta) 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 effective May 30, 2019. As a result, Alberta become a "listed province" under the federal GGPPA and 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.

Alberta's Bill 19: *Technology Innovation and Emissions Reduction Implementation Act, 2019* ("**TIER**") received royal assent on November 22, 2019. Together with its accompanying regulations, the *Technology Innovation and Emissions Reduction Regulation* (the "**TIER Regulation**") varied Alberta's system of managing pollution caps and taxes on large emitters. Previously, large emitters were subject to a cap and trade system under the *Carbon Competitiveness Incentive Regulation* ("**CCIR**") which was enacted pursuant to the former *Climate Change and Emissions Management Act* ("**CCEMA**"). Following the implementation of TIER, CCEMA was renamed the *Emissions Management and Climate Resilience Act*. On December 6, 2019, the Federal Government approved the TIER Regulation. Accordingly, the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER Regulation replaced CCIR on January 1, 2020.

The TIER Regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of $CO_2e$ per year in 2016 or any subsequent year. Emitters can apply for a facility-specific benchmark, under which their 2020 target is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER Regulation targets emissions intensity rather than total emissions. Under the TIER Regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000-tonne threshold. A facility can opt-in to TIER Regulation if it competes directly against another TIER-regulated facility or if it has annual $CO_2e$ emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive-trade-exposed sector (as defined in the TIER Regulation). In addition, the "person responsible" for two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER Regulation and, therefore, be subject to provincial rather than federal 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 *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") came into force 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 updated Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the Federal Government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the $CO_2$ emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million tonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010* (Alberta). 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.

**Accountability and Transparency**

In 2015, 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 CDN$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 the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally. If any of the risks set out below materialize, the Corporation's business, financial condition, results of operations, prospects, cash flow and reputation may be adversely affected, which may, in turn, reduce or restrict the Corporation's ability to pay dividends and may materially affect the market price of the Corporation's securities.**

**Prices, Markets and Marketing**

***Various factors may adversely impact the prices and marketability of oil, natural gas and NGLs, affecting the Corporation's revenue, production volumes, development and exploration activities, value of its reserves, cash flow and ability to access capital***

The Corporation's revenue, operating results and financial condition depend substantially on prevailing prices for oil and natural gas and the Corporation's ability to successfully market its oil and natural gas production from its properties. Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced or discovered by the Corporation.

The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas, crude oil and NGLs to commercial markets or contract for the delivery of crude oil by rail (see *"Industry Conditions – Transportation Constraints and Market Access", "Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry"* and *"Risk Factors – Gathering and Processing Facilities, Pipeline Systems and Rail"*). Deliverability uncertainties include the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities and operational problems affecting pipelines, railway lines and facilities.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond the Corporation's control. These factors include, but are not limited to, the following:

- global energy supply and demand;

- the actions taken by OPEC and other oil and gas exporting nations;
- political conditions, instability and hostilities;
- domestic and foreign supplies of crude oil, NGLs and natural gas;
- the level of consumer demand, including demand for different qualities and types of crude oil and NGLs;
- the production and storage levels of North American natural gas and crude oil and the supply and price of imported oil;
- the ability to export oil, LNG and NGLs from North America;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized prices for oil and natural gas;
- weather conditions;
- government regulations, including existing and proposed changes to such regulations;
- the effect of world-wide environmental regulations and energy conservation and GHG reduction measures;
- the price and availability of alternative energy supplies; and
- global and domestic economic conditions, including currency fluctuations.

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. Market events and conditions, including global excess oil and natural gas supply, actions taken by OPEC, sanctions against Iran and Venezuela, conflict between the United States and Iran, slowing growth in China and emerging economies, weakening global relationships, isolationist and punitive trade policies, increased shale production in the United States, sovereign debt levels, the outbreak of COVID-19 and political upheavals in various countries (including growing anti-fossil fuel sentiment) have caused significant volatility in commodity prices. Prices for crude oil and natural gas are also impacted by the availability of foreign markets and the ability to access such markets.

Any substantial and prolonged decline in the price of oil and natural gas would have an adverse effect on the carrying value of the Corporation's assets, borrowing capacity, revenue, profitability and cash flow from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations, prospects, its ability to pay dividends and ultimately on the market prices of the Corporation's securities.

A material decline in oil and natural gas prices could result in a reduction in the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas. The Corporation might also elect not to produce from certain wells at lower prices. In addition, any prolonged period of low crude oil or natural gas prices could result in a decision by the Corporation to suspend or slow exploration and development activities or the construction or expansion of new or existing facilities or reduce its production levels.

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 the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or exploitation projects.

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic for development. The Corporation's reserves at December 31, 2019 are estimated using forecast prices and costs. If oil and natural gas prices stay at current levels or decrease, the Corporation's reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics. Any decrease in the value of the Corporation's reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. See *"Risk Factors – Credit Facilities".*

In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure programs. The Corporation's capital expenditure plans are impacted by the Corporation's cash flow. 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.

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 its oil and natural gas assets on its balance sheet and the recognition of an impairment charge on its income statement.

**Weakness and Volatility in the Oil and Natural Gas Industry**

***Declining general economic, business or industry conditions may have a material adverse effect on the Corporation's results of operations, liquidity and financial condition***

Concerns over global economic conditions, fluctuations in interest rates and foreign exchange rates, stock market volatility, energy costs, geopolitical issues, OPEC actions, inflation, the availability and cost of credit, the deceleration of economic growth in the People's Republic of China, trade disputes between the United States and the People's Republic of China, civil unrest in Venezuela and Iran and the outbreak of COVID-19 have contributed to increased economic uncertainty and diminished expectations for the global economy over the past few years. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks, including attacks on oil infrastructure in oil producing nations, in the United States or other countries could adversely affect the economies of Canada, the United States and other countries.

Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in Canada, the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which the Corporation can sell its oil, NGLs and natural gas, affect the ability of the Corporation's vendors, suppliers and customers to continue operations and ultimately adversely impact the Corporation's results of operations, liquidity and financial condition.

These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in the 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. In addition, difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, LNG 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, Brent and WTI crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See *"Industry Conditions".*

**Exploration, Development and Production Risks**

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

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at a particular point in time and the production therefrom, will decline over time as such existing reserves are produced. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in the development. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas. The success of the Corporation's business is highly dependent on its ability to acquire or discover new reserves in a cost-efficient manner as substantially all of the Corporation's cash flow is derived from the sale of the petroleum and natural gas reserves that it accumulates and develops. In order to remain financially viable, the Corporation must be able to replace reserves over time at a lesser cost on a per unit basis than its cash flow on a per unit basis.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or 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, the shutting-in 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 and utilization of enhanced 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 or the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour natural 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 the Corporation's business, financial condition, results of operations and prospects.

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

**Project Risks**

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

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

- the availability and proximity of processing and pipeline capacity;
- the availability of storage capacity;

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

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to effectively market the oil and natural gas that it produces.

**Gathering and Processing Facilities, Pipeline Systems and Rail**

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

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas produced and sold by the Corporation 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 the 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"*). In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas and could result in the inability of the Corporation to realize the full economic potential of the produced oil or natural gas or a reduction of the price offered for the production from its properties. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production and operations which may have a material adverse effect on its business and financial condition. 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 Québec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the CEAA were repealed. In addition, the IA Agency replaced the CEA Agency. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation"*. The impact of the new federal regulatory scheme on the oil and natural gas industry and the timing for receipt of approvals of major projects is unclear.

The Corporation's production passes through Birchcliff owned or third-party infrastructure prior to it being ready for sale. There is a risk that should this infrastructure fail and cause a significant portion of the Corporation's production to be shut-in and unable to be sold, this could have a material adverse effect on the Corporation's available cash flow. With respect to facilities owned by third parties and over which the Corporation has no control, these facilities may discontinue or decrease operations, either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the

Corporation's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Further, the Corporation has certain long-term take-or-pay commitments to deliver products through third-party owned infrastructure which creates a financial liability and there can be no assurance that future volume commitments will be met which may adversely affect the Corporation's financial condition and cash flow from operations.

**Uncertainty of Reserves and Resource Estimates**

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

There are numerous uncertainties inherent in estimating oil, natural gas and NGLs reserves and the future net revenue attributed to such reserves. The reserves and associated future net revenue information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil, natural gas and NGLs reserves and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserves recovery, the timing and amount of capital expenditures, marketability of oil, natural gas and NGLs, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the economically recoverable oil, natural gas and NGLs reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenue associated with reserves prepared by different engineers, or by the same engineer at different times, may vary. The Corporation's actual production, revenue, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof 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 in Canada, the Corporation's independent qualified reserves evaluators have used forecast prices and costs in estimating the reserves and future net revenue as summarized herein. Actual future net revenue 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 regulations or taxation and the impact of inflation on costs.

Actual production and cash flow derived from the Corporation's reserves will vary from the estimates contained in the Corporation's independent reserves evaluations and such variations could be material. The independent reserves evaluations are based in part on the assumed success of activities the Corporation intends to take in future years. The reserves and estimated future net revenue to be derived therefrom and contained in the Corporation's independent reserves evaluations will be reduced to the extent that such activities do not achieve the level of success assumed in the evaluations.

This Annual Information Form also contains estimates of the volumes of the Corporation's contingent resources and prospective resources, as well as the net present value of the future net revenue associated with the best estimate of development pending contingent resources. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of contingent resources. The uncertainty in estimating prospective resources is even greater. Actual results may vary significantly from these estimates and such variances could be material. In addition, there are contingencies that prevent contingent resources from being classified as reserves. With respect to the Corporation's contingent resources, there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the Corporation's prospective resources, there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

The Consolidated Reserves Report, the Deloitte Reserves Report, the McDaniel Reserves Report and the 2019 Resource Assessment are effective as of December 31, 2019 and, except as may be specifically stated or required by applicable securities laws, have not been updated since that date and therefore do not reflect changes since that date.

**Substantial Capital and Additional Funding Requirements**

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

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

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

The Corporation's cash flow from its properties may not be sufficient to fund its ongoing activities at all times and from time to time the Corporation may require additional financing. The inability of the Corporation to access sufficient capital for its operations and activities could have a material adverse effect on the Corporation's financial condition, results of operations and prospects.

Due to the conditions in the oil and natural gas industry, global economic and political conditions and the domestic landscape, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The conditions in or affecting the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. 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 its operations.

There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet the Corporation's requirements or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. 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 Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. Moreover, future activities may require the Corporation to alter its capitalization significantly.

**Political Uncertainty**

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

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the U.S. administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reforms, which, among other things, significantly reduces U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In late January 2020, the Canadian Parliament tabled Bill C-4, which once proclaimed into force, will ratify the USMCA. The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force (see *"Industry Conditions – NAFTA 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 condition, results of operations, prospects and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the political disruption in the United States, the impact of the United Kingdom's exit from the European Union remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues 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 could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's business, reduce access to skilled labour and negatively impact the Corporation's business, financial condition, results of operations, prospects and the market value of its securities.

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. Although the Supreme Court of Canada unanimously rejected the Government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia in January 2020, tensions 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 jurisdictions where the Corporation's properties are located.

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 government 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"* and *"Industry Conditions – The North American Free Trade Agreement and other Trade Agreements"*.

**Climate Change**

***Climate change may pose varied and far ranging risks to the business and operations of the Corporation, both known and unknown, which may adversely affect its business, operations and financial condition***

The Corporation has grouped its risks related to climate change into two main categories: physical risks and transition risks. Physical risks have been further sub-divided into acute physical risks (those that are event-driven, including increased severity of extreme weather events) and chronic physical risks (those that relate to longer-term shifts in climate patterns). Transition risks have been further sub-divided into reputational, market, regulatory and policy, legal and technology risks. For a description of the climate change regulation applicable to the Corporation, see *"Description of the Business – Environmental Protection Regulation and Costs"* and *"Industry Conditions – Climate Change Regulation".*

*Physical Risks – Acute*

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict or interfere with the Corporation's operations, increasing its costs and negatively impacting its production. Moreover, extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced oil and natural gas, as well as goods and services in their supply chains. Certain of the Corporation's properties are located in locations that are proximate to forests and rivers and a wildfire or flood, respectively, may lead to significant downtime and/or damage to such assets which may affect production. At this time, the Corporation is unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting its operations.

*Physical Risks – Chronic*

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 also *"Risk Factors – Seasonality".*

In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storms and fires and prolonged heat waves may, among other things, require the Corporation to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety, which may in turn have a material adverse effect on the Corporation's business, operations and financial condition. In the event of water shortages or sourcing issues, the Corporation may not be able to, or will incur greater costs to, carry out hydraulic fracturing. See also *"Risk Factors – Hydraulic Fracturing".*

*Transition Risks – Reputational*

The Corporation's business, financial condition, operations or prospects may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment towards, 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. 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 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 Québec advocacy group, applied to the Québec 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. See also

*"Risk Factors – Changing Investor Sentiment", "Risk Factors – Public Opinion and Reputational Risk"* and *"Risk Factors – Public Opposition and Non-Governmental Organizations".*

*Transition Risks – Market*

Concerns over climate change, fossil fuels, GHG emissions and water and land-use could lead to reduced demand for the oil, natural gas and NGLs that the Corporation produces, which would have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See also *"Risk Factors – Alternatives to and Changing Demand for Petroleum Products".*

*Transition Risks – Regulatory and Policy*

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. Existing and future laws and regulations may impose significant liabilities for a failure to comply with their requirements. Concerns over climate change, fossil fuels, GHG emissions and water and land-use could lead to the enactment of more stringent laws and regulations applicable to the Corporation. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's business, financial condition, results of operations and prospects.

Adverse impacts to the Corporation's business as a result of GHG legislation may include, but are not limited to, increased compliance costs, permitting delays, increased operating costs and capital expenditures. Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term, potentially reducing the demand for oil and natural gas resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or requiring impairments for financial statement purposes.

The Corporation's exploration and production facilities and other operations and activities emit GHGs which requires the Corporation to comply with applicable GHG emissions legislation. The Corporation is subject to TIER and the Corporation may become subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. See *"Description of the Business – Environmental Protection Regulation and Costs"* for further details.

See also *"Industry Conditions – Climate Change Regulation", "Risk Factors – Regulatory", "Risk Factors – Environmental", "Risk Factors – Evolving Corporate Governance and Reporting Framework"* and "*Risk Factors – Carbon Pricing Risk".*

*Transition Risks – Legal*

The Corporation may become involved in, be named as a party to or be the subject of, various legal proceedings related to climate change. See also *"Risk Factors – Litigation".*

*Transition Risks – Technology*

The adoption of new technologies by the Corporation to deal with climate change could require a significant capital investment. See also *"Risk Factors – Cost of New Technologies".*

**Changing Investor Sentiment**

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

A number of factors, including the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the 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 of their investments of such entities 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 Corporation's Board, management and employees. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Corporation or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, in the Corporation, may result in limiting Birchcliff's access to capital, increasing the cost of capital and decreasing the price and liquidity of the Corporation's securities, even if the Corporation's operating results, underlying asset value or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's assets which may result in an impairment charge.

**Public Opinion and Reputational Risk**

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

The Corporation's business, financial condition, operations and prospects may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment towards, 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 licences and increased costs and/or cost overruns. See also *"Risk Factors – Public Opposition and Non-Governmental Organizations".*

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage its reputation. Negative sentiment towards the Corporation could result in a lack of willingness of governmental authorities to grant the necessary licences or permits for the Corporation to operate its business. In addition, negative sentiment towards the Corporation could result in the residents of the areas where the Corporation is doing business opposing further operations in the area by the Corporation. If the Corporation develops a reputation of having an unsafe workplace, this may impact its ability to attract and retain the necessary skilled employees and consultants to operate its business. Further, the Corporation's reputation could be affected by actions and activities of other corporations operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Further, 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 harm 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.

**Public Opposition and Non-Governmental Organizations**

***The oil and natural gas industry and the Corporation may be subject to public opposition and other actions by non-governmental organizations***

The oil and natural gas industry may, at times, be subject to public opposition. 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. Such public opposition could expose the Corporation to the risk of higher costs, operational delays and disruptions or even project cancellations due to increased pressure on governments and regulators by special interest groups, which may include Indigenous groups, landowners, environmental interest groups (including those opposed to oil and gas production operations) and other non-governmental organizations. Potential impacts of such pressure and opposition include blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences, as well as direct legal challenges, including the possibility of climate-related litigation. There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require significant and unanticipated capital and operating expenditures which may negatively impact the Corporation's business, financial condition, results of operations and prospects.

In addition, the Corporation's oil and natural gas properties, wells and facilities or the third-party facilities and pipelines utilized by the Corporation could be the subject of a terrorist attack. If any of such properties, wells or facilities are the subject of terrorist attack, it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

**Alternatives to and Changing Demand for Petroleum Products**

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

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

**Regulatory**

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

The implementation of new regulations or the modification to existing regulations affecting the oil and natural gas industry could reduce the demand for crude oil and natural gas, increase the Corporation's costs or make certain projects uneconomic, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Further, the ongoing third-party challenges to regulatory decisions and 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 the business of the oil and natural gas industry. See *"Industry Conditions".*

In order to conduct oil and natural gas operations, the Corporation requires regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation 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, the Corporation may have to comply with the requirements of certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada), which may adversely affect its business and financial condition and the market value of its securities or assets, particularly when undertaking, or attempting to undertake, an acquisition or disposition.

**Environmental**

***Compliance with environmental regulations requires the dedication of a portion of the Corporation'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 municipal laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects and 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 the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

In addition, political and economic events may significantly affect the scope and timing of climate change measures that are put in place. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the oil and natural gas industry generally could reduce demand for oil and natural gas and increase costs. See *"Risk Factors – Climate Change"*.

**Carbon Pricing Risk**

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

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the Federal Government has 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 – Climate Change Regulation"*.

Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts companies at an economic disadvantage with their counterparts who operate in jurisdictions where there are less costly carbon regulations. See also *"Risk Factors – Climate Change"* and *"Risk Factors – Environmental".*

**Credit Facilities**

***The Corporation's borrowing base under the Credit Facilities could be redetermined and the Corporation could fail to comply with covenants under the Credit Facilities, resulting in restricted access to capital or a requirement to repay all amounts owing thereunder***

The amount authorized under the Credit Facilities is dependent on the borrowing base determined by the Corporation's lenders. The Credit Facilities are subject to semi-annual reviews of the borrowing base limit by Birchcliff's syndicate of lenders, which limit is directly impacted by the value of Birchcliff's oil and natural gas reserves. The Corporation's lenders use the Corporation's reserves, commodity prices and other factors to determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. Continued depressed commodity prices or further declines in commodity prices could result in a reduction in the Corporation's borrowing base, thereby reducing the funds available to the Corporation under the Credit Facilities. As the borrowing base is determined based on the lender's interpretation of the Corporation's reserves and future commodity prices, there can be no assurance as to the amount of the borrowing base determined at each review.

In addition to the semi-annual reviews of the borrowing limit, the lenders have the right to redetermine the borrowing base limit in certain other circumstances. In the event that: (i) the Corporation, any material subsidiary of the Corporation or any of its borrowing base properties become subject to an abandonment/reclamation order by an energy regulator where the aggregate estimated current cost to the Corporation and its material subsidiaries to comply with all outstanding orders exceeds 10% of the borrowing base; or (ii) the liability management rating (as such term is defined in the agreement governing the Credit Facilities) of the Corporation or any material subsidiary is less than 2.0, then, unless agreed to by all of the lenders, a redetermination of the borrowing base shall be completed within 45 days of receipt by the Corporation or the applicable material subsidiary of such order or demand in the case of (i) above, and of receipt by the agent of notice that the liability management rating is less than 2.0 in the case of (ii) above. Further, a majority of lenders have the right once per year to redetermine the borrowing base in between scheduled redeterminations and the borrowing base may also be reduced in connection with asset dispositions.

If, at the time of a borrowing base redetermination, the outstanding borrowings under the Credit Facilities were to exceed the borrowing base as a result of any such redetermination, the Corporation would be required to make principal repayments or otherwise eliminate the borrowing base shortfall. If the Corporation is forced to repay a portion of its indebtedness under the Credit Facilities, it may not have sufficient funds to make such repayments. If it does not have sufficient funds and is otherwise unable to negotiate renewals of its borrowings or arrange new financing, it may have to sell significant assets. Any such sale could have a material adverse effect on the Corporation's business and financial results.

The maturity date of the Credit Facilities is currently May 11, 2022. The Corporation may each year, at its option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made. In the event that either of the Credit Facilities is not extended before the maturity date, all outstanding indebtedness under such Credit Facility will be repayable at the maturity date. There is also a risk that the Credit Facilities will not be renewed for the same principal amount or on the same terms. Any of these events could adversely affect the Corporation's ability to fund its ongoing operations and to pay dividends.

The Corporation is required to comply with covenants under the Credit Facilities. In the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in an event of default under the Credit Facilities, which could result in the Corporation being required to repay amounts owing thereunder and may prevent the payment of dividends to shareholders. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross-default or cross-acceleration provisions. In addition, the Credit Facilities impose certain restrictions on the Corporation, including, but not limited to, restrictions on the payment of dividends, incurring of additional indebtedness, dispositions of properties and the entering into of amalgamations, mergers, plans of arrangements, reorganizations or consolidations with any person.

The Credit Facilities do not currently contain any financial maintenance covenants; however, there is no assurance that the Corporation's lenders will not impose any such covenants on the Corporation in the future. Any such covenants may either affect the availability or price of additional funding.

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

**Issuance of Debt**

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

From time to time, the Corporation may finance its activities (including asset acquisitions) in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for peers of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

**Hedging**

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

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. Similarly, the Corporation may enter into agreements to fix the differential or discount pricing gap which exists and may fluctuate between different grades of oil, NGLs and natural gas and the various market prices received for such products. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements 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; and/or
- a sudden unexpected material event impacts crude oil and natural gas prices.

Similarly, the Corporation may enter into agreements to fix the exchange rate of Canadian dollars 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 the other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Further, the Corporation may enter into hedging arrangements to fix interest rates applicable to the Corporation's debt. However, if interest rates decrease as compared to the interest rate fixed by the Corporation, the Corporation will not benefit from the lower interest rate.

**Market Prices of the Corporation's Securities**

***The trading price of the Corporation's securities may be volatile and adversely affected by factors related and unrelated to the oil and natural gas industry and cannot be accurately predicted***

The market price of the Corporation's securities may be volatile, which may affect the ability of holders to sell such securities at an advantageous price. The trading price of the securities of oil and natural gas issuers, including the Corporation, is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the oil and natural gas market. This includes, but is not limited to, changing (and in some cases negative) investor sentiment towards energy-related businesses. In recent years, the volatility of commodities has increased due to, in part, 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. Further, 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 prices of the Corporation's securities could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. In addition, market price fluctuations in the Corporation's securities may also be due to the Corporation's results failing to meet the expectations of securities analysts or investors in any quarter, downward revisions in securities analysts' estimates and material public announcements by the Corporation, along with a variety of additional factors, including, without limitation, those set forth under "*Special Notes to Reader – Forward-Looking Statements"*. Accordingly, the prices at which the Corporation's securities will trade cannot be accurately predicted.

**Hydraulic Fracturing**

***Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's business and 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. While hydraulic fracturing has been in use for many years, there has been increased focus on the environmental aspects of hydraulic fracturing practices in recent years. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition (including litigation) to oil and natural gas production activities using hydraulic fracturing techniques. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third-party or governmental claims and could increase the Corporation's costs of compliance and doing business, as well as delay the development of oil and natural gas resources from certain formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves and, therefore, could adversely affect the Corporation's business, financial condition, results of operations and prospects.

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

**Competition**

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

The oil and natural gas industry is highly competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil and natural gas, including land, acquisitions of reserves, access to drilling and service rigs and other equipment, access to transportation and access to skilled technical and operating personnel. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling.

**Variations in Foreign Exchange Rates and Interest Rates**

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

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

To the extent that the Corporation engages in risk management activities related to foreign exchange and interest rates, there is credit risk associated with the counterparties with whom the Corporation may contract. See also *"Risk Factors – Hedging"*.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities and the cash available for dividends and could negatively impact the market prices of the Corporation's securities.

**Availability and Cost of Equipment, Materials and Services**

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

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized equipment and other materials (typically leased from third parties) and skilled personnel trained to use such equipment in the areas where such activities will be conducted. The availability of such equipment, materials and personnel is limited. An increase in demand or cost, or a decrease in the availability of, such equipment, materials or personnel may impede the Corporation's exploration, development and operating activities, which, in turn, could materially adversely affect the Corporation's business and financial condition.

**Potential Future Drilling Locations**

***The Corporation's identified potential future drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling***

The Corporation's identified potential future drilling locations represent a significant part of the Corporation's future growth. The Corporation's ability to drill and develop these locations and the drilling locations on which the

Corporation actually drills wells depends on a number of uncertainties and factors, including, but not limited to, the availability of capital, equipment and personnel, oil and natural gas prices, costs, inclement weather, seasonal restrictions, drilling results, additional geological, geophysical and reservoir information that is obtained, production rate recovery, gathering system and transportation constraints, the net price received for commodities produced, regulatory approvals and regulatory changes. As a result of these uncertainties, there can be no assurance that the potential future drilling locations that Birchcliff has identified will ever be drilled and, if drilled, that such locations will result in additional oil, NGLs or natural gas production and, in the case of unbooked locations, additional reserves. As such, the Corporation's actual drilling activities may differ materially from those presently identified, which could adversely affect the Corporation's business.

**Seasonality**

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

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. In addition, certain oil and natural gas producing properties are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Further, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas typically fluctuates during cold winter months and hot summer months.

**All Assets in One Area**

***All of the Corporation's properties are located in the Peace River Arch area of Alberta, making the Corporation vulnerable to risks associated with having its production concentrated in one area***

All of the Corporation's producing properties are geographically concentrated in the Peace River Arch area of Alberta. As a result of this concentration, the Corporation may be disproportionately exposed to the impact of delays or interruptions of production from that area caused by transportation capacity constraints, curtailment of production, natural disasters, availability of equipment, facilities or services, adverse weather conditions or other events which impact that area. Due to the concentrated nature of the Corporation's portfolio of properties, a number of the Corporation's properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on the Corporation's results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on the Corporation's financial condition and results of operations.

**Cost of New Technologies**

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

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

**Dividends**

***The payment of dividends could vary***

The declaration and payment of future dividends (and the amount thereof) is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, the financial condition of Birchcliff, production levels, results of operations, capital expenditure requirements, working capital requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, interest rates, contractual restrictions, Birchcliff's hedging activities or programs, available investment opportunities, Birchcliff's business plan, strategies and objectives, the satisfaction of the solvency and liquidity tests imposed by the ABCA for the declaration and payment of dividends and other factors that the Board may deem relevant. Depending on these and various other factors, many of which are beyond the control of Birchcliff, the dividend policy of the Corporation may vary from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

Pursuant to the ABCA, the Corporation may not declare or pay a dividend if there are reasonable grounds for believing that: (i) the Corporation is, or would after the payment be, unable to pay its liabilities as they become due; or (ii) the realizable value of its assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares. Additionally, pursuant to the agreement governing the Credit Facilities, the Corporation is not permitted to make any distribution (which includes dividends) at any time when an event of default exists or would reasonably be expected to exist upon making such distribution, unless such event of default arose subsequent to the ordinary course declaration of the applicable distribution.

Dividends may be reduced or suspended during periods of lower cash flow from operations. The timing and amount of Birchcliff's capital expenditures, and the ability of the Corporation to repay or refinance existing debt as it becomes due, directly affects the amount of cash dividends that may be declared by the Board. Future acquisitions, expansions of Birchcliff's assets, and other capital expenditures and the repayment or refinancing of existing debt as it becomes due may be financed from sources such as cash flow from operations, the issuance of additional shares or other securities of Birchcliff, and borrowings. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made. There can be no assurance that sufficient capital will be available on terms acceptable to Birchcliff, or at all, to make additional investments, fund future expansions or make other required capital expenditures. To the extent that external sources of capital, including the issuance of additional shares or other securities or the availability of additional credit facilities, become limited or unavailable on favourable terms or at all due to credit market conditions or otherwise, the ability of the Corporation to make the necessary capital investments to maintain or expand its operations, to repay outstanding debt and to invest in assets, as the case may be, may be impaired. To the extent Birchcliff is required to use cash flow from operations to finance capital expenditures or acquisitions or to repay existing debt as it becomes due, the cash available for dividends may be reduced and the level of dividends declared may be reduced or suspended entirely.

Over time, the Corporation's capital and other cash needs may change significantly from its current needs, which could affect whether the Corporation pays dividends and the amount of dividends, if any, it may pay in the future. If the Corporation continues to pay dividends at the current levels, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn.

The market value of the Corporation's securities may deteriorate if 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 Birchcliff and potential legislative and regulatory changes.

**Reliance on a Skilled Workforce and Key Personnel**

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

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

Competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

**Earnings Volatility**

***Earnings of the Corporation may fluctuate in each reporting period***

The Corporation's accounting policies conform to IFRS which constitutes generally accepted accounting principles in Canada. Accounting under IFRS may result in non-cash charges and/or write-downs of net assets in the financial statements on a quarterly basis. Similarly, non-cash gains and reversals of asset write-downs may also be recorded from time to time. Income statement volatility resulting from such non-cash gains and losses under IFRS may be viewed unfavourably by the market and could result in an inability to borrow funds and/or could result in a decline in the price of the Corporation's securities.

**Management of Growth and Integration**

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

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

**Information Technology Systems and Cyber-Security**

***A disruption of information technology services or a cyber-security breach may adversely affect the Corporation***

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

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

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

To date, the Corporation has not been subject to a cyber-security attack or other breach that has had a material impact on its business or operations or resulted in material losses to the Corporation; however, there is no assurance that the measures the Corporation takes to protect its business systems and operational control systems will be effective in protecting against a breach in the future and that the Corporation will not incur such losses in the future.

**Insurance**

***Not all risks are insurable and the occurrence of an uninsurable event may have a material adverse effect on the Corporation***

Although the Corporation maintains insurance in accordance with industry standards to address certain risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or for other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

**Ligation**

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

In the normal course of the Corporation's operations, it may become involved in, be named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Such proceedings may develop in relation to personal injury (including claims resulting from exposure to hazardous substances), property damage, property taxes, land and access rights, royalty rights, the environment (including claims relating to contamination) and lease and contractual disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and, as a result, could have a material adverse effect on the Corporation's 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 the Corporation's business operations, which may adversely affect the Corporation.

Due to the rapid development of oil and natural gas technology, the Corporation may become involved in, be named as a party to or be the subject of, various legal proceedings in which it is alleged that the Corporation has infringed the intellectual property rights of others or conversely, the Corporation may commence lawsuits against others who the Corporation believes are infringing upon its intellectual property rights. The Corporation's involvement in intellectual property litigation could result in significant expense, adversely affecting the development of its assets or intellectual property or diverting the efforts of its technical and management personnel, whether or not such litigation is resolved in the Corporation's favour. In the event of an adverse outcome as a defendant in any such litigation, the Corporation may, among other things, be required to: (i) pay substantial damages; (ii) cease the use of infringing intellectual property; (iii) expend significant resources to develop or acquire non-infringing intellectual property; (iv) discontinue processes incorporating infringing technology; or (v) obtain licences to the infringing intellectual property. However, the Corporation may not be successful in such development or acquisition or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on the Corporation's business and financial results.

**Indigenous Claims**

***Indigenous claims may affect the Corporation***

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. The Corporation is not aware that any claims have been made in respect of its properties or assets; however, the legal basis of an Indigenous land claim and Indigenous rights are matters of considerable legal complexity and the impact of the assertion of such a claim, or the possible effect of a settlement of such claim, upon the Corporation cannot be predicted with any degree of certainty. In addition, no assurance can be given that any recognition of Indigenous rights or claims whether by way of a negotiated settlement or by judicial pronouncement (or through the grant of an injunction prohibiting exploration or development activities pending resolution of any such claim) would not delay or even prevent the Corporation's exploration and development activities. If a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

In addition, claims and protests of Indigenous peoples may disrupt or delay third-party operations or new development on the Corporation's properties.

**Credit Risk**

***The Corporation is exposed to credit risk through its contractual arrangements and its third-party operators or partners of properties in which it has an interest***

The Corporation may be exposed to third-party credit risk through its contractual arrangements with joint venture partners, marketers of its oil 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 joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Conversely, the Corporation's counterparties may deem the Corporation to be at risk of defaulting on its contractual obligations. These counterparties may require that the Corporation provide additional credit assurance by prepaying anticipated expenses or posting letters of credit, which would decrease the Corporation's available liquidity.

**Internal Controls**

***Material weaknesses in the Corporation's internal controls may negatively affect the Corporation and the market price of the Corporation's securities***

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation undertakes a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and negatively impact the trading prices of the Corporation's securities.

**Liability Management Programs**

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

Alberta has developed the AB LMR Program which is designed to prevent taxpayers from incurring costs associated with the 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 the AB LMR Program may result in the requirement for security to be posted in the future and may result in significant increases to the Corporation's compliance obligations.

The impact and consequences of the Supreme Court of Canada's decision in the Redwater case on the AER's rules and policies, lending practices in the oil and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the AB LMR Program (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 – Alberta – Liability Management Rating Program"*.

**Title to and Right to Produce from Assets**

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

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

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

**Expiration of Licences and Leases**

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

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

**Disposal of Fluids Used in Operations**

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

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

**Breaches of Confidentiality**

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

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

**Operational Dependence**

***The Corporation is subject to risk as it pertains to other parties operating assets it has an interest in***

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

In addition, due to the current low and volatile commodity price environment, 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 recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due to it 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 effect on the Corporation's financial and operational results.

**Risks Associated with Acquisitions and Dispositions**

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

The Corporation considers acquisitions and dispositions of assets in the ordinary course of business. Typically, once an acquisition opportunity is identified, a review of available information relating to the assets is conducted. There is a risk that even a detailed review of records and assets may not necessarily reveal every existing or potential problem, nor will it permit the Corporation to become sufficiently familiar with the assets to fully assess their deficiencies and potential. There is no guarantee that defects in the chain of title will not arise to defeat the Corporation's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Corporation may assume certain environmental and other risk liabilities in connection with acquired assets.

In addition, acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geological, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and assets may require substantial management effort, time and resources, diverting management's focus away from other strategic opportunities and operational matters.

Management continually assesses the value and contribution of the various assets within its portfolio. In this regard, certain assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on market conditions for such assets, there is a risk that certain assets of the Corporation could realize less than their carrying value on the Corporation's financial statements.

**Royalty Regimes**

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

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

**Negative Impact of Additional Sales or Issuances of Securities**

***The Corporation may issue additional securities, diluting current shareholders***

The Corporation may issue an unlimited number of Common Shares without any vote or action by the shareholders, subject to the rules of any stock exchange on which the Corporation's securities may be listed. The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation. If the Corporation issues additional securities, the percentage ownership of existing shareholders will be reduced and diluted and the price of the Corporation's securities could decrease.

**Conflicts of Interest**

***Conflicts of interest may arise for the Corporation's directors and officers***

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

**Income Taxes**

***Taxation authorities may reassess the Corporation's tax returns***

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *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 the Corporation, 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 the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

**Additional Taxation Applicable to Non-Residents**

***Non-resident shareholders are required to pay additional taxes on their dividends***

Tax legislation in Canada may impose withholding or other taxes on the cash dividends, stock dividends or other property transferred by the Corporation to non-resident shareholders. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Evidence of eligibility for a reduced withholding rate must be filed by the non-resident shareholder in prescribed form with their broker (or in the case of registered shareholders, with the transfer agent). In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

**Foreign Exchange Risk for Non-Resident Shareholders**

***Variations in foreign exchange rates may affect the amount of cash dividends received by shareholders who receive dividends in currencies other than Canadian dollars***

The Corporation's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders and shareholders who calculate their return in currencies other than the Canadian dollar are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of any dividend will be reduced when converted to their home currency.

**Evolving Corporate Governance and Reporting Framework**

***Evolving corporate governance and reporting framework may increase both compliance costs and the risk of non-compliance that may have an adverse effect on the Corporation***

The Corporation's business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of non-compliance, which could have an adverse effect on the Corporation's costs of doing business. The Corporation is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities Administrators, the TSX and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity, making compliance more difficult and uncertain. Further, the Corporation's efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

**Social Media**

***The Corporation faces compliance and supervisory challenges in respect of the use of social media as a means of communicating***

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

**Expansion into New Activities**

***Expanding the Corporation's business may expose it to new risks and uncertainties***

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

### Public Health Crises

***Public health crises, including COVID-19, could adversely affect the Corporation's business***

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 and on January 30, 2020, the World Health Organization declared the outbreak a global health emergency. In China, reactions to the spread of COVID-19 have led to, among other things, significant restrictions on travel within China, temporary business closures, quarantines and a general reduction in consumer activity. The outbreak has spread throughout Europe and the Middle East and there have been cases of COVID-19 in Canada and the United States, causing companies and various international jurisdictions to impose restrictions such as quarantines, business closures and travel restrictions. While these effects are expected to be temporary, the duration of the business disruptions internationally and related financial impact cannot be reasonably estimated at this time. Similarly, the Corporation cannot estimate whether or to what extent this outbreak and the potential financial impact may extend to countries outside of those currently impacted.

Such public health crises can result in volatility and disruptions in the supply and demand for oil and natural gas, global supply chains and financial markets, as well as declining trade and market sentiment and reduced mobility of people, all of which could affect commodity prices, interest rates, credit ratings, credit risk and inflation. In particular, oil prices have significantly weakened in response to the outbreak of COVID-19. See *"Risk Factors – Prices, Markets and Marketing"* and *"Risk Factors – 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.

### Forward-Looking Information

***Forward-looking information may prove inaccurate***

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking statements. By their nature, forward-looking statements involve numerous assumptions and 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 statements or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties relating to forward-looking statements is found under the heading *"Special Notes to Reader – Forward-Looking Statements"*.

## DIVIDEND AND DISTRIBUTION POLICY

### Common Shares

The Corporation's Common Share dividend policy establishes that until changed by the Board, dividends will be paid to the holders of Common Shares for the quarters ending March 31, June 30, September 30 and December 31. The payment date for any dividends declared shall be the last day of March, June, September and December; provided that, if any such date is not a business day, the payment date shall be the next business day. The record date for determining the holders of Common Shares entitled to receive dividends is expected to be on or about the $15^{th}$ day of the last month of the applicable quarter. Unless otherwise determined by the Board, all dividends shall be paid in cash. The dividend policy is periodically reviewed by the Board and no assurance or guarantee can be given that Birchcliff will maintain the dividend policy in its current form.

Birchcliff does not have a dividend reinvestment plan or stock dividend program.

**Preferred Shares – Series A and Series C Preferred Shares**

The Corporation has Series A Preferred Shares and Series C Preferred Shares outstanding, on which dividends have been paid to their holders in accordance with their terms. See *"Description of Capital Structure – Authorized Share Capital and Securities Outstanding – Preferred Shares".*

## Dividend History

The following tables set forth details regarding the dividends that were declared on the Common Shares, the Series A Preferred Shares and the Series C Preferred Shares during the three most recently completed financial years:

***Common Shares***

| Declaration Date | Record Date | Payment Date | Type | Amount |
|---|---|---|---|---|
| November 26, 2019 | December 16, 2019 | December 31, 2019 | Quarterly, Cash | $0.02625 |
| September 3, 2019 | September 16, 2019 | September 30, 2019 | Quarterly, Cash | $0.02625 |
| June 4, 2019 | June 17, 2019 | July 2, 2019 | Quarterly, Cash | $0.02625 |
| February 13, 2019 | March 15, 2019 | April 1, 2019 | Quarterly, Cash | $0.02625 |
| November 28, 2018 | December 17, 2018 | December 31, 2018 | Quarterly, Cash | $0.025 |
| September 5, 2018 | September 17, 2018 | October 1, 2018 | Quarterly, Cash | $0.025 |
| May 29, 2018 | June 15, 2018 | July 3, 2018 | Quarterly, Cash | $0.025 |
| February 28, 2018 | March 15, 2018 | April 2, 2018 | Quarterly, Cash | $0.025 |
| November 30, 2017 | December 15, 2017 | January 2, 2018 | Quarterly, Cash | $0.025 |
| September 5, 2017 | September 15, 2017 | October 2, 2017 | Quarterly, Cash | $0.025 |
| May 30, 2017 | June 15, 2017 | June 30, 2017 | Quarterly, Cash | $0.025 |
| March 1, 2017 | March 15, 2017 | March 31, 2017 | Quarterly, Cash | $0.025 |

***Series A Preferred Shares***

| Declaration Date | Record Date | Payment Date | Type | Amount |
|---|---|---|---|---|
| November 26, 2019 | December 16, 2019 | December 31, 2019 | Quarterly, Cash | $0.523375 |
| September 3, 2019 | September 16, 2019 | September 30, 2019 | Quarterly, Cash | $0.523375 |
| June 4, 2019 | June 17, 2019 | July 2, 2019 | Quarterly, Cash | $0.523375 |
| February 13, 2019 | March 15, 2019 | April 1, 2019 | Quarterly, Cash | $0.523375 |
| November 28, 2018 | December 17, 2018 | December 31, 2018 | Quarterly, Cash | $0.523375 |
| September 5, 2018 | September 17, 2018 | October 1, 2018 | Quarterly, Cash | $0.523375 |
| May 29, 2018 | June 15, 2018 | July 3, 2018 | Quarterly, Cash | $0.523375 |
| February 28, 2018 | March 15, 2018 | April 2, 2018 | Quarterly, Cash | $0.523375 |
| November 30, 2017 | December 15, 2017 | January 2, 2018 | Quarterly, Cash | $0.523375 |
| September 5, 2017 | September 15, 2017 | October 2, 2017 | Quarterly, Cash | $0.50 |
| May 30, 2017 | June 15, 2017 | June 30, 2017 | Quarterly, Cash | $0.50 |
| March 1, 2017 | March 15, 2017 | March 31, 2017 | Quarterly, Cash | $0.50 |

***Series C Preferred Shares***

| Declaration Date | Record Date | Payment Date | Type | Amount |
|---|---|---|---|---|
| November 26, 2019 | December 16, 2019 | December 31, 2019 | Quarterly, Cash | $0.4375 |
| September 3, 2019 | September 16, 2019 | September 30, 2019 | Quarterly, Cash | $0.4375 |
| June 4, 2019 | June 17, 2019 | July 2, 2019 | Quarterly, Cash | $0.4375 |
| February 13, 2019 | March 15, 2019 | April 1, 2019 | Quarterly, Cash | $0.4375 |
| November 28, 2018 | December 17, 2018 | December 31, 2018 | Quarterly, Cash | $0.4375 |
| September 5, 2018 | September 17, 2018 | October 1, 2018 | Quarterly, Cash | $0.4375 |
| May 29, 2018 | June 15, 2018 | July 3, 2018 | Quarterly, Cash | $0.4375 |
| February 28, 2018 | March 15, 2018 | April 2, 2018 | Quarterly, Cash | $0.4375 |
| November 30, 2017 | December 15, 2017 | January 2, 2018 | Quarterly, Cash | $0.4375 |
| September 5, 2017 | September 15, 2017 | October 2, 2017 | Quarterly, Cash | $0.4375 |
| May 30, 2017 | June 15, 2017 | June 30, 2017 | Quarterly, Cash | $0.4375 |
| March 1, 2017 | March 15, 2017 | March 31, 2017 | Quarterly, Cash | $0.4375 |

On February 26, 2020, the Board declared the following dividends for the quarter ending March 31, 2020: (i) a cash dividend of $0.02625 per share on the Common Shares; (ii) a cash dividend of $0.523375 per share on the Series A Preferred Shares; and (iii) a cash dividend of $0.4375 per share on the Series C Preferred Shares. The dividends are payable on March 31, 2020 to shareholders of record at the close of business on March 16, 2020.

**The declaration and payment of dividends is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time. The payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely. In addition to the foregoing, the Corporation's ability to pay dividends now or in the future may be limited by covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future, including the terms of the Credit Facilities. The Credit Facilities provide that Birchcliff is not permitted to make any distribution (including dividends) at any time when an event of default exists or would reasonably be expected to exist upon making such distribution, unless such event of default arose subsequent to the ordinary course declaration of the applicable distribution. For further information regarding the risks and assumptions relating to the payment of dividends, see *"Risk Factors – Dividends"*.**

## DESCRIPTION OF CAPITAL STRUCTURE

### Authorized Share Capital and Securities Outstanding

The authorized share capital of the Corporation consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares, each without par value. In addition, the Corporation also has Performance Warrants and Options that are outstanding which are exercisable into Common Shares.

The following table sets forth the securities of the Corporation that were outstanding at December 31, 2019:

| Authorized Securities Outstanding | Number of Securities |
|---|---|
| Common Shares | 265,935,229 |
| Series A Preferred Shares | 2,000,000 |
| Series C Preferred Shares | 2,000,000 |
| Performance Warrants | 2,939,732 |
| Options | 23,483,368 |

The following is a summary of the rights, privileges, restrictions and conditions which attach to the Common Shares and the Preferred Shares as a class:

#### *Common Shares*

Shareholders are entitled to receive notice of, to attend and to one vote per Common Share at all meetings of holders of Common Shares, except meetings at which only holders of a specified class of shares are entitled to vote. Shareholders are entitled to receive any dividend declared by the Corporation on the Common Shares; provided that the Corporation shall be entitled to declare dividends on the Preferred Shares or on any of such classes of shares without being obliged to declare any dividends on the Common Shares. Subject to the rights, privileges, restrictions and conditions attaching to any other class of shares of the Corporation, holders of Common Shares are entitled to receive the remaining property of the Corporation upon dissolution in equal rank with the holders of other Common Shares.

On November 20, 2018, the Corporation announced that the TSX had accepted the Corporation's notice of intention to make a normal course issuer bid pursuant to which the Corporation could purchase for cancellation up to 18,767,520 of its outstanding Common Shares. This normal course issuer bid commenced on November 23, 2018 and terminated on November 22, 2019. No Common Shares were purchased or cancelled during this period.

On November 19, 2019, the Corporation announced that the TSX had accepted the Corporation's notice of intention to make a normal course issuer bid pursuant to which the Corporation could purchase for cancellation up to 13,296,761 of its outstanding Common Shares. This normal course issuer bid commenced on November 25, 2019 and will terminate no later than November 24, 2020. All Common Shares purchased under the bid will be cancelled. The actual number of Common Shares purchased pursuant to the bid and the timing of such purchases will be determined by Birchcliff and there can be no assurance as to how many Common Shares, if any, will ultimately be acquired by the Corporation. As at the date hereof, the Corporation has not purchased any Common Shares under the bid.

### *Preferred Shares*

The Preferred Shares may from time to time be issued in one or more series and the Board may fix from time to time before such issue the number of Preferred Shares which is to comprise each series and the designation, rights, privileges, restrictions and conditions attaching to each series of Preferred Shares including, without limiting the generality of the foregoing, any voting rights, the rate or amount of dividends or the method of calculating dividends, the dates of payment thereof, the terms and conditions of redemption, purchase and conversion, if any, and any sinking fund or other provisions.

The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other return of capital or distribution of the assets of Birchcliff amongst its shareholders for the purpose of winding up its affairs, be entitled to preference over the Common Shares and over any other shares of the Corporation ranking by their terms junior to the Preferred Shares of that series. The Preferred Shares of any series may also be given such other preferences, not inconsistent with the articles of the Corporation, over the Common Shares and any other Preferred Shares as may be fixed by the Board.

If any cumulative dividends or amounts payable on the return of capital in respect of a series of Preferred Shares are not paid in full, all series of Preferred Shares shall participate rateably in respect of accumulated dividends and return of capital.

In the event of the liquidation, dissolution or winding-up of the Corporation, the holders of Series A Preferred Shares, Series B Preferred Shares and Series C Preferred Shares are entitled to receive $25.00 per share plus all accrued and unpaid dividends thereon, before any amount is paid or any property or assets are distributed to holders of the Common Shares.

*Series A Preferred Shares and Series B Preferred Shares*

The Series A Preferred Shares and the Series B Preferred Shares are identical in all material respects other than different dividend rights, redemption rights and conversion rights attached thereto. There are currently no Series B Preferred Shares outstanding.

On August 8, 2012, the Corporation issued an aggregate of 2,000,000 Series A Preferred Shares. The holders of the outstanding Series A Preferred Shares are entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends, payable quarterly. The dividend rate of the Series A Preferred Shares reset on September 30, 2017 and will reset every five years thereafter at a rate equal to the then current five-year Government of Canada bond yield plus 6.83%. The dividend rate for the initial period from and including the date of issue to, but excluding September 30, 2017, was $2.00 per share per year. The dividend rate for the five-year period from and including September 30, 2017 to, but excluding September 30, 2022, is 8.374%.

The Series A Preferred Shares were redeemable by the Corporation on September 30, 2017 and are redeemable by the Corporation on September 30 in every fifth year thereafter, at a redemption price of $25.00 per share, plus all accrued and unpaid dividends.

The holders of the Series A Preferred Shares had the right to convert their shares into an equal number of Series B Preferred Shares on September 30, 2017, subject to certain conditions being met. On August 14, 2017, the Corporation announced it did not intend to exercise its right to redeem the Series A Preferred Shares on September 30, 2017. As a result, the holders of the Series A Preferred Shares had the right to choose to retain any or all of their Series A Preferred Shares and continue to receive a fixed rate quarterly dividend or to convert, on a one-for-one basis, any or all of their Series A Preferred Shares into Series B Preferred Shares and receive a floating rate quarterly dividend. On September 18, 2017, the Corporation announced that the holders of the Series A Preferred Shares were not entitled to convert their Series A Preferred Shares into Series B Preferred Shares as only 165,960 Series A Preferred Shares had been tendered for conversion, which was less than the 250,000 shares required to give effect to the conversion. As a result, none of the outstanding Series A Preferred Shares were converted into Series B Preferred Shares on September 30, 2017. Subject to redemption by the Corporation, holders of the Series A

Preferred Shares will have the opportunity to convert their shares into Series B Preferred Shares again on September 30, 2022, and every five years thereafter as long as the shares remain outstanding.

*Series C Preferred Shares*

On June 14, 2013, the Corporation issued 2,000,000 Series C Preferred Shares. The holders of the outstanding Series C Preferred Shares are entitled to receive, as and when declared by the Board, fixed cumulative preferential cash dividends at an annual rate of $1.75 per share, payable quarterly. The Series C Preferred Shares are redeemable by the Corporation on and after June 30, 2018 at a redemption price of $25.75 per share if redeemed before June 30, 2019, at a redemption price of $25.50 per share if redeemed on or after June 30, 2019 but before June 30, 2020 and at a redemption price of $25.00 per share if redeemed on or after June 30, 2020, in each case together with all accrued and unpaid dividends. As at the date hereof, the Corporation has not redeemed any of the Series C Preferred Shares.

On and after June 30, 2020, the holders of Series C Preferred Shares may redeem their shares for cash on the last day of March, June, September and December of each year at $25.00 per share, together with all accrued and unpaid dividends. Upon receipt of a notice of redemption from the holder, the Corporation may elect to convert such Series C Preferred Shares into Common Shares. The number of Common Shares into which each Series C Preferred Share may be so converted will be determined by dividing the amount of $25.00, together with all accrued and unpaid dividends, by the greater of $2.00 and 95% of the weighted average trading price of the Common Shares on the TSX for a period of 20 consecutive trading days ending on the fourth day prior to the date specified for conversion (the "**Current Market Price**"). In addition, on and after June 30, 2018, the Corporation may convert the outstanding Series C Preferred Shares into Common Shares. The number of Common Shares into which each Series C Preferred Share may be so converted will be determined by dividing the then applicable redemption price, together with all accrued and unpaid dividends, by the greater of $2.00 and 95% of the Current Market Price. Any conversion of the Series C Preferred Shares will be subject to the approval of the TSX, if required.

**Performance Warrants**

The Performance Warrants were originally granted on January 18, 2005 at the founding of the Corporation to the executive officers of Birchcliff at the time of grant. Each Performance Warrant entitles the holder thereof to purchase one Common Share at an exercise price of $3.00. The Performance Warrants were designed to act as a long-term retention incentive for the holders and to enhance shareholder value by aligning the interests of the holders with the growth and profitability of the Corporation. The Performance Warrants were specifically designed to provide a performance-based incentive to the holders upon the trading price of the Common Shares exceeding $6.00. Accordingly, the Performance Warrants were not exercisable unless the trading price of the Common Shares exceeded $6.00 for a period of 20 consecutive trading days. This condition was satisfied in November 2005 and all of the Performance Warrants have been exercisable since that time.

The outstanding Performance Warrants are held by Messrs. Tonken, Geremia, Surbey and Bosman, each of whom is an executive officer and/or director of the Corporation. On May 23, 2019, the holders of Common Shares approved an amendment to the outstanding Performance Warrants to extend the expiry date of such Performance Warrants from January 31, 2020 to January 31, 2025.

**Options**

Pursuant to the Stock Option Plan, Options may be granted from time to time to the officers, directors, employees and certain service providers of the Corporation. Options are granted by the Board who, at the time of the grant, fixes the exercise price, vesting dates and the expiry date of such Options. The maximum number of Common Shares that are issuable under Options that are issued and outstanding at any time under the Stock Option Plan shall not exceed 10% of the aggregate number of Common Shares actually issued and outstanding at that time, as determined on a non-diluted basis.

The Stock Option Plan provides that the expiry date of an Option shall be no later than 10 years from the date of grant of such Option and that the exercise price of an Option shall be determined by the Board but shall not be lower than the higher of: (i) the closing price of the Common Shares on the TSX on the first trading day immediately preceding the date of grant; or (ii) the lowest price permitted by the TSX. All of the Options granted to date under the Stock Option Plan provide for: (i) the expiry of such Options not later than the fifth anniversary of the date of grant; and (ii) the vesting of such Options with respect to one-third of the Common Shares issuable thereunder on each of the first, second and third anniversaries of the date of grant.

**Credit Facilities**

The Corporation has extendible revolving credit facilities in the aggregate principal amount of $1.0 billion (the "**Credit Facilities**") which are comprised of an extendible revolving syndicated term credit facility (the "**Syndicated Credit Facility**") in the amount of $900.0 million and an extendible revolving working capital facility (the "**Working Capital Facility**") in the amount of $100.0 million. The Credit Facilities allow for prime rate loans, LIBOR loans, U.S. base rate loans, bankers' acceptances and, in the case of the Working Capital Facility only, letters of credit.

The maturity date of each of the Syndicated Credit Facility and the Working Capital Facility is currently May 11, 2022. The Corporation may each year, at its option, request an extension to the maturity date of the Syndicated Credit Facility and the Working Capital Facility, or either of them, for an additional period of up to three years from May 11 of the year in which the extension request is made. The Credit Facilities are subject to semi-annual reviews of the borrowing base limit by the Corporation's syndicate of lenders, which are typically completed in May and November of each year. The Credit Facilities do not contain any financial maintenance covenants.

For further information regarding the Credit Facilities, see the Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2019. See also *"Risk Factors – Credit Facilities"*.

## MARKET FOR SECURITIES

**Trading Price and Volume**

The Common Shares, the Series A Preferred Shares and the Series C Preferred Shares are listed for trading on the TSX under the trading symbols "BIR", "BIR.PR.A" and "BIR.PR.C", respectively. The following table sets forth the price ranges and trading volumes of the Common A Shares, the Series A Preferred Shares and the Series C Preferred Shares on the TSX during the year ended December 31, 2019:

| | Common Shares | | | Series A Preferred Shares | | | Series C Preferred Shares | | |
|---|---|---|---|---|---|---|---|---|---|
| **Month** | **High ($)** | **Low ($)** | **Monthly Trading Volume** | **High ($)** | **Low ($)** | **Monthly Trading Volume** | **High ($)** | **Low ($)** | **Monthly Trading Volume** |
| January | 3.54 | 2.92 | 20,648,688 | 24.99 | 24.25 | 27,306 | 24.70 | 24.20 | 27,744 |
| February | 3.74 | 3.03 | 17,674,304 | 25.29 | 24.50 | 10,230 | 24.45 | 23.85 | 20,523 |
| March | 4.00 | 3.41 | 13,263,761 | 25.40 | 24.75 | 22,202 | 24.76 | 24.40 | 8,912 |
| April | 3.98 | 3.41 | 11,036,524 | 25.89 | 25.09 | 9,900 | 25.10 | 24.80 | 23,219 |
| May | 3.94 | 3.08 | 25,014,724 | 25.95 | 25.35 | 11,639 | 25.20 | 24.80 | 39,979 |
| June | 3.20 | 2.55 | 16,123,517 | 25.49 | 24.18 | 22,192 | 25.50 | 24.65 | 53,039 |
| July | 3.05 | 2.52 | 18,488,734 | 25.01 | 24.60 | 15,652 | 24.93 | 24.68 | 35,660 |
| August | 2.66 | 1.69 | 37,278,525 | 24.80 | 23.25 | 23,412 | 24.65 | 23.75 | 43,226 |
| September | 2.57 | 1.71 | 41,508,963 | 25.25 | 23.29 | 18,655 | 24.81 | 23.12 | 21,630 |
| October | 2.27 | 1.91 | 18,993,689 | 24.79 | 24.05 | 31,635 | 25.26 | 23.74 | 26,856 |
| November | 2.45 | 1.97 | 28,080,964 | 24.75 | 24.26 | 35,024 | 25.44 | 25.00 | 25,200 |
| December | 2.65 | 2.05 | 20,363,743 | 25.24 | 24.47 | 43,902 | 25.59 | 25.20 | 19,054 |

**Prior Sales**

During the year ended December 31, 2019, the only securities the Corporation issued which are outstanding but are not listed or quoted on a marketplace were an aggregate of 10,107,200 Options which were granted at exercise prices ranging from $1.77 to $3.90 per Common Share.

## ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the Corporation's knowledge, at December 31, 2019, no securities of Birchcliff were held in escrow or subject to a contractual restriction on transfer.

## DIRECTORS AND OFFICERS

### Directors

The following table sets forth for each person who is a director of the Corporation at the date hereof: (i) their name, province and country of residence and whether they are independent; (ii) the period during which they have served as a director of the Corporation or its predecessor entities; and (iii) their principal occupation during the past five years or more:

| Name, Province and Country of Residence | Director Since | Principal Occupation During the Past Five Years or More |
|---|---|---|
| **Dennis A. Dawson**(1)(2)(3)(4)<br>*Alberta, Canada*<br>Independent | May 14, 2015 | Mr. Dawson is a director of Birchcliff, is the independent Lead Director and is the Chair of the Compensation Committee and the Nominating Committee. He has over 33 years of oil and natural gas experience, including nine years as General Counsel for Pan-Alberta Gas Ltd., a major Canadian natural gas export and marketing company. Mr. Dawson was the Vice-President, General Counsel and Corporate Secretary of AltaGas from December 1998 until April 2015. He first joined AltaGas as Associate General Counsel in August 1997, after consulting with AltaGas Services Inc. from July 1996. Effective July 1998, Mr. Dawson became AltaGas' General Counsel and Corporate Secretary and effective December 1998, he became Vice-President, General Counsel and Corporate Secretary. He received a Bachelor of Arts degree from the University of Lethbridge and a Bachelor of Laws degree from the University of Alberta and is a member of the Law Society of Alberta. |
| **Debra A. Gerlach**(1)(2)(3)(4)<br>*Alberta, Canada*<br>Independent | November 8, 2017 | Ms. Gerlach is a director of Birchcliff and is the Chair of the Audit Committee. From September 1996 until September 2017, Ms. Gerlach was a partner with Deloitte LLP where she practiced in the Assurance and Advisory group. Prior thereto, she held various positions within Deloitte LLP from the time she joined the firm in August 1982. During her 35-year career with the firm, Ms. Gerlach worked with numerous public oil and gas companies. Ms. Gerlach is a Chartered Accountant with the Chartered Professional Accountants of Alberta and received a Bachelor of Commerce degree and a Master of Business Administration degree from the University of Calgary. |
| **Stacey E. McDonald**(1)(2)(3)(4)<br>*Alberta, Canada*<br>Independent | December 14, 2018 | Ms. McDonald is a director of Birchcliff and has over 14 years of experience in the energy and financial sectors. From September 2016 to July 2018, Ms. McDonald was a Managing Director – Institutional Equity Research (Energy) at GMP FirstEnergy and its predecessor, GMP Securities, independent global investment banks. She joined GMP Securities in February 2006 as a research associate and began publishing independently as an Equity Analyst in 2009. Ms. McDonald received a Bachelor of Commerce degree in Finance from the University of Alberta. |

| Name, Province and Country of Residence | Director Since | Principal Occupation During the Past Five Years or More |
|---|---|---|
| **James W. Surbey**[3]<br>*Alberta, Canada*<br>Non-independent | May 11, 2017 | Mr. Surbey is a director of Birchcliff and is the Chair of the Reserves Evaluation Committee. He is also an employee of Birchcliff and an independent businessman. Mr. Surbey has over 42 years of experience in the oil and natural gas industry and is one of the Corporation's founders. He was the Vice-President, Corporate Development and Corporate Secretary of Birchcliff from the inception of the Corporation until June 30, 2017. Prior to joining Birchcliff, he served as the Vice-President, Corporate Development of Case Resources Inc., the Senior Vice-President, Corporate Development of Big Bear Exploration Ltd. and the Vice-President, Corporate Development of Stampeder Exploration Ltd. Mr. Surbey was previously a senior partner of the law firm Howard, Mackie (now Borden Ladner Gervais LLP). He received a Bachelor of Engineering degree and a Bachelor of Laws degree from McGill University and is a member of the Law Society of Alberta and the Society of Petroleum Engineers. |
| **A. Jeffery Tonken**<br>*Alberta, Canada*<br>Non-independent | July 6, 2004 | Mr. Tonken is the Chairman of the Board and the President and Chief Executive Officer of the Corporation. See his biography under *"Directors and Officers –Executive Officers"*. |

(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Reserves Evaluation Committee.
(4) Member of the Nominating Committee.

The directors of the Corporation hold office until the close of the next annual meeting of shareholders of the Corporation or until their successors are elected or appointed. The next annual meeting of the shareholders of the Corporation is scheduled for May 14, 2020.

### Executive Officers

The following table sets forth for each person who is an executive officer of the Corporation at the date hereof: (i) their name, province and country of residence; (ii) their position with the Corporation; and (iii) their principal occupation during the past five years or more:

| Name and Province and Country of Residence | Current Position with Birchcliff | Principal Occupation During the Past Five Years or More |
|---|---|---|
| **A. Jeffery Tonken**<br>*Alberta, Canada* | Chairman of the Board and President and Chief Executive Officer | Mr. Tonken has been the President and Chief Executive Officer and a director of Birchcliff since the inception of the Corporation and the Chairman of the Board since May 2017. He has over 39 years of experience in the oil and natural gas industry and is one of the Corporation's founders. Prior to Birchcliff, Mr. Tonken founded and served as the President and Chief Executive Officer of Case Resources Inc., Big Bear Exploration Ltd. and Stampeder Exploration Ltd. He was previously a partner of the law firm Howard, Mackie (now Borden Ladner Gervais LLP). Mr. Tonken is also the Chair of the Board of Governors of the Canadian Association of Petroleum Producers (CAPP). He received a Bachelor of Commerce degree from the University of Alberta and a Bachelor of Laws degree from the University of Wales and is a member of the Law Society of Alberta. |

| Name and Province and Country of Residence | Current Position with Birchcliff | Principal Occupation During the Past Five Years or More |
|---|---|---|
| **Myles R. Bosman**<br>*Alberta, Canada* | Vice-President, Exploration and Chief Operating Officer | Mr. Bosman has been the Vice-President, Exploration and Chief Operating Officer of Birchcliff since the inception of the Corporation. He is a Professional Geologist with over 29 years of experience in the oil and natural gas industry and is one of the Corporation's founders. Prior to joining Birchcliff, Mr. Bosman served as the Vice-President, Exploration and Chief Operating Officer of Case Resources Inc., the Exploration Manager of Summit Resources Ltd. and as an Exploration Geologist with both Numac Energy Inc. and Canadian Hunter Exploration. He received a Bachelor of Science degree in Geology from the University of Calgary and a Resource Engineering diploma from the Northern Alberta Institute of Technology and is a member of APEGA. |
| **Christopher A. Carlsen**<br>*Alberta, Canada* | Vice-President, Engineering | Mr. Carlsen has been the Vice-President, Engineering of Birchcliff since July 2013 and prior thereto, he was an Asset Team Lead and Senior Exploitation Engineer with Birchcliff. He is a Professional Engineer with over 19 years of experience in the oil and natural gas industry. Prior to joining Birchcliff, Mr. Carlsen was the Senior Engineer at Greenfield Resources Ltd. and held various engineering positions at both Encana Corporation and PanCanadian Petroleum Ltd. He received a Bachelor of Science degree in Chemical Engineering from the University of Saskatchewan and is a member of APEGA. |
| **Bruno P. Geremia**<br>*Alberta, Canada* | Vice-President and Chief Financial Officer | Mr. Geremia has been the Vice-President and Chief Financial Officer of Birchcliff since the inception of the Corporation. He is a Chartered Accountant with over 28 years of experience in the oil and natural gas industry and is one of the Corporation's founders. Prior to joining Birchcliff, Mr. Geremia served as the Vice-President and Chief Financial Officer of both Case Resources Inc. and Big Bear Exploration Ltd., as the Director, Commercial of Gulf Canada Resources and as the Manager, Special Projects of Stampeder Exploration Ltd. He was previously a Chartered Accountant with Deloitte & Touche LLP. Mr. Geremia received a Bachelor of Commerce degree from the University of Calgary. |
| **David M. Humphreys**<br>*Alberta, Canada* | Vice-President, Operations | Mr. Humphreys has been the Vice-President, Operations of Birchcliff since October 2009. He has 34 years of experience in the oil and natural gas industry. Prior to joining Birchcliff in 2009, he served as Vice-President, Operations of Highpine Oil & Gas Ltd., White Fire Energy Ltd. and Virtus Energy Ltd. and Production Manager of both Husky Oil Operations Limited and Ionic Energy. Mr. Humphreys received his Hydrocarbon Engineering Technology diploma from the Northern Alberta Institute of Technology and is a member of ASET. He also has a Professional Licensee (Engineering) designation with APEGA. Mr. Humphreys is the Vice Chair of The Explorers and Producers Association of Canada (EPAC) and sits on the Safety Standards Council for Energy Safety Canada. |

### Shareholdings of Directors and Executive Officers

At March 10, 2020: (i) the directors and executive officers of the Corporation, as a group, beneficially owned, or controlled or directed, directly or indirectly, 3,378,984 Common Shares, representing approximately 1.3% of the issued and outstanding Common Shares; and (ii) the executive officers of the Corporation, as a group, held Performance Warrants and Options to acquire a further 7,474,765 Common Shares.

### Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Except as disclosed below, none of the directors or executive officers of the Corporation is, as at the date of this Annual Information Form, or was within 10 years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company including the Corporation that: (i) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days (an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Except as disclosed below, none of the directors or executive officers of the Corporation or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation: (i) is, as at the date of this Annual Information Form, or has been within the 10 years before the date of this Annual Information Form, a director or executive officer of any company including the Corporation that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

From July 8, 2010 to February 20, 2018, Mr. Geremia was a director of Manitok Energy Inc., a company listed on the TSX Venture Exchange. On January 10, 2018, Manitok announced that it had filed a Notice of an Intention to Make a Proposal pursuant to the provisions of the *Bankruptcy and Insolvency Act* (Canada), naming FTI Consulting Canada Inc. as the proposed trustee. Manitok was unable to form a proposal with its creditors within 30 days after filing its Notice of Intention and as a result, on February 20, 2018, the Court of Queen's Bench of Alberta issued a Receivership Order placing Manitok into receivership and substituting Alvarez & Marsal Canada Inc. in place of FTI as the trustee in bankruptcy. The Court also appointed Alvarez as the receiver and manager of Manitok and terminated the Notice of Intention. All of the directors of Manitok, including Mr. Geremia, resigned. On May 4, 2018, a cease trade order was issued against Manitok under the securities legislation of Alberta and Ontario for failure to file annual audited financial statements and annual management's discussion and analysis for the year ended December 31, 2017.

None of the directors or executive officers of the Corporation or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

### Conflicts of Interest

Directors and executive officers of the Corporation may invest in or become directors or officers of other oil and natural gas companies or entities that may provide financing to, or make equity investments in, competitors of the Corporation, which may give rise to conflicts of interest. Conflicts, if any, will be governed by the ABCA. Pursuant to the ABCA, directors and executive officers of the Corporation are required to disclose the nature and extent of any interest that they have in a material contract or material transaction, and in the case of a director, such director will refrain from voting on any matter in respect of such contract or transaction, unless otherwise provided by the ABCA.

## AUDIT COMMITTEE

### Audit Committee Charter

The Charter adopted by the Audit Committee of the Corporation is attached hereto as Appendix D.

### Composition of the Audit Committee and Relevant Education and Experience

As at the date hereof, the Audit Committee is comprised of Mr. Dennis A. Dawson, Ms. Debra A. Gerlach and Ms. Stacey E. McDonald. Ms. Gerlach is Chair of the Audit Committee. Each of the members of the Audit Committee is "independent" and "financially literate" within the meaning of NI 52-110. The following table sets forth the relevant education and experience of each member of the Audit Committee:

| Name | Independent? | Financially Literate? | Relevant Education and Experience |
|---|---|---|---|
| Dennis A. Dawson | Yes | Yes | Mr. Dawson has over 33 years of oil and natural gas experience, including nine years as General Counsel for Pan-Alberta Gas Ltd., a major Canadian natural gas export and marketing company. Mr. Dawson was the Vice-President, General Counsel and Corporate Secretary of AltaGas from December 1998 until April 2015. He received a Bachelor of Arts degree from the University of Lethbridge and a Bachelor of Laws degree from the University of Alberta. |
| Debra A. Gerlach (Chair) | Yes | Yes | Ms. Gerlach was a partner with Deloitte LLP from September 1996 until September 2017, where she practiced in the Assurance and Advisory group. Prior thereto, she held various positions within Deloitte from the time she joined the firm in August 1982. During her 35-year career with the firm, Ms. Gerlach worked with numerous public oil and gas companies. Ms. Gerlach is a Chartered Accountant with the Chartered Professional Accountants of Alberta and received a Bachelor of Commerce degree and a Master of Business Administration degree from the University of Calgary. |
| Stacey E. McDonald | Yes | Yes | Ms. McDonald has over 14 years of experience in the energy and financial sectors. From September 2016 to July 2018, Ms. McDonald was a Managing Director – Institutional Equity Research (Energy) at GMP FirstEnergy and its predecessor, GMP Securities, independent global investment banks. Ms. McDonald joined GMP Securities in February 2006 as a research associate and began publishing independently as an Equity Analyst in 2009. Ms. McDonald received a Bachelor of Commerce degree in Finance from the University of Alberta. |

### Pre-Approval Policies and Procedures

The Charter adopted by the Audit Committee provides that all non-audit services to be provided to the Corporation by the Corporation's external auditor must be pre-approved by the Audit Committee. The Audit Committee may delegate this function to one of its independent members, who shall report to the Audit Committee on any such approvals.

### External Auditor Service Fees

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

| Fees | 2019 | 2018 |
|---|---|---|
| Audit Fees[(1)] | $336,000 | $319,000 |
| Audit-Related Fees[(2)] | - | - |
| Tax Fees[(3)] | $105,514 | $24,292 |
| All Other Fees[(4)] | - | - |
| **Total** | **$441,514** | **$343,292** |

(1) "Audit Fees" consist of fees for the audit of the Corporation's annual financial statements and the review of the Corporation's quarterly financial statements, as well as services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) "Audit-Related Fees" consist of fees for assurance and related services that are reasonably related to the performance of the audit or the review of the Corporation's financial statements and are not reported under the heading of "Audit Fees" above.

(3) "Tax Fees" consist of fees for professional services rendered for tax compliance, tax advice and tax planning. During 2019 and 2018, such fees related to the preparation and filing of Birchcliff's corporate income tax returns and other tax-related work.

(4) "All Other Fees" consist of fees for products and services other than those described under the headings of "Audit Fees", "Audit-Related Fees" and "Tax Fees" above.

## LEGAL PROCEEDINGS AND REGULATORY ACTIONS

The Corporation's 2006 income tax filings were reassessed by the CRA in 2011. The reassessment was based on the CRA's position that the tax pools available to Veracel, prior to its amalgamation with Birchcliff, ceased to be available to Veracel after Birchcliff and Veracel amalgamated on May 31, 2005. The Veracel tax pools in dispute totalled $39.3 million. Birchcliff appealed the reassessment to the Tax Court of Canada and the trial of that appeal occurred in November 2013. On October 1, 2015, the Tax Court of Canada issued its decision (the "**TCC Decision**") and dismissed Birchcliff's appeal on the basis of the general anti-avoidance rule contained in the *Income Tax Act* (Canada). The TCC Decision was rendered by a judge based on the written record and not by the judge who conducted the trial. As a result of the TCC Decision, Birchcliff recorded a non-cash deferred income tax expense in the amount of $10.2 million in the fourth quarter of 2015. Birchcliff appealed the TCC Decision to the Federal Court of Appeal, which appeal was heard in January 2017. On April 28, 2017, the Federal Court of Appeal issued its decision and allowed the appeal and set aside the TCC Decision, based on the lack of jurisdiction by the judge who rendered the TCC Decision. In setting aside the TCC Decision, the Federal Court of Appeal referred the matter back to the judge of the Tax Court of Canada who initially conducted the trial in 2013 to render a judgment. The judge of the Tax Court of Canada rendered a decision in November 2017 and dismissed Birchcliff's appeal. The Corporation appealed that decision to the Federal Court of Appeal, which appeal was heard on December 10, 2018. The Federal Court of Appeal rendered a decision in May 2019 dismissing the Corporation's appeal. The Corporation filed an application for leave to appeal to the Supreme Court of Canada, which was denied on November 14, 2019.

There are no other material legal proceedings that the Corporation is or was a party to, or that any of its property is or was the subject of, during the most recently completed financial year or that the Corporation knows to be contemplated.

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

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of: (i) any director or executive officer of the Corporation; (ii) any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares; or (iii) any associate or affiliate of any of the persons or companies referred to in (i) or (ii), in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Corporation.

## TRANSFER AGENT AND REGISTRAR

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

## MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation did not enter into any material contracts within the last financial year, or before the last financial year but which are still in effect.

## INTERESTS OF EXPERTS

### Names of Experts

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

**Interests of Experts**

KPMG LLP performed the audit in respect of the audited annual financial statements of the Corporation as at and for the years ended December 31, 2019 and December 31, 2018. KPMG LLP has confirmed that they are independent of the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

The Corporation's independent qualified reserves evaluator, Deloitte, prepared the Deloitte Reserves Report, the Consolidated Reserves Report, the Prior Consolidated Reserves Report, the 2019 Resource Assessment and the 2018 Resource Assessment. As at the date hereof, the designated professionals (as defined in NI 51-102) of Deloitte, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding securities of the Corporation.

The Corporation's independent qualified reserves evaluator, McDaniel, prepared the McDaniel Reserves Report. As at the date hereof, the designated professionals of McDaniel, as a group, beneficially own, directly or indirectly, less than 1% of the outstanding securities of the Corporation.

In addition, none of the aforementioned persons or companies, nor any partner, 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 the Corporation.

## ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com and on the Corporation's website at www.birchcliffenergy.com. Additional information, including the remuneration and indebtedness of the directors and executive officers of the Corporation, the principal holders of Common Shares and the securities authorized for issuance under equity compensation plans, is contained in the information circular of the Corporation for the most recent annual meeting of the holders of Common Shares, which was held on May 16, 2019.

Additional financial information relating to the Corporation is provided in the Corporation's audited annual financial statements and related management's discussion and analysis for the year ended December 31, 2019.

## APPENDIX A

## DISCLOSURE OF CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA

Birchcliff engaged Deloitte to prepare an independent evaluation of resources in respect of Birchcliff lands that have potential for the Montney/Doig Resource Play effective December 31, 2019, which is contained in a report dated March 11, 2020 (the "**2019 Resource Assessment**"). Deloitte also prepared a resource assessment effective December 31, 2018 (the "**2018 Resource Assessment**"). The 2019 Resource Assessment and the 2018 Resource Assessment were prepared in accordance with the standards contained in the COGE Handbook and NI 51-101 in effect at the relevant time.

Resource estimates contained herein at December 31, 2019 and 2018 are extracted from the relevant resource assessment and reflect only resources on Birchcliff's Montney/Doig lands. The resource assessments did not include any of Birchcliff's other properties. All anticipated results disclosed herein were prepared by Deloitte, who is an independent qualified reserves evaluator. Deloitte utilized probabilistic methods to generate high, best and low estimates of resource volumes.

Certain terms used herein are defined under the headings *"Glossary of Terms"* and *"Presentation of Oil and Gas Reserves and Resources"* in the Annual Information Form. Certain other terms used herein but not defined are defined in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101, CSA Staff Notice 51-324 or the COGE Handbook, as the case may be.

All of Birchcliff's resources are located in the Province of Alberta. Unless otherwise indicated, all volumes of Birchcliff's resources presented herein are on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality, and all volumes are presented on a gross basis, meaning Birchcliff's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of Birchcliff. Numbers in the tables presented herein may not total due to rounding.

**The estimates of Birchcliff's resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. With respect to Birchcliff's discovered resources (including contingent resources), there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to Birchcliff's undiscovered resources (including prospective resources), there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Estimates of future net revenue, whether calculated without discount or using a discount rate, do not represent fair market value. See *"Risk Factors and Uncertainties"* in this Appendix A and *"Risk Factors – Uncertainty of Reserves and Resource Estimates"* in the Annual Information Form to which this Appendix A is attached.**

For further information regarding the presentation of Birchcliff's resource disclosure, see *"Presentation of Oil and Gas Reserves and Resources"* and *"Special Notes to Reader"* in the Annual Information Form.

### Interest of Birchcliff in Resources in the Study Area

Birchcliff holds significant high working interest acreage in large contiguous blocks on the Montney/Doig Resource Play in the Peace River Arch area of Alberta. Birchcliff engaged Deloitte to evaluate the total PIIP and contingent and prospective resources on Birchcliff's lands for the Doig Phosphate ("**DoigP**"), Basal Doig ("**BD**") and Montney formations in the Montney/Doig Deep Basin area of northwest Alberta (the "**Study Area**"). In the Study Area, Birchcliff owns an interest in approximately 388.4 gross (374.2 net) sections of land which include Montney rights (inclusive of oil sections in the Gordondale area) and 366.1 gross (336.5 net) sections of land which include Doig rights. This includes 2.5 gross sections which were outside of the geo-model boundaries and therefore do not have reported volumes. As compared to the 2018 Resource Assessment, these numbers are up approximately 11% for Montney rights on a net basis (346.4 (338.4 net) sections as contained in the 2018 Resource Assessment) and 12%

for Doig rights on a net basis (322.1 (300.7 net) sections as contained in the 2018 Resource Assessment), primarily as a result of land acquisitions completed by the Corporation during 2019.

In the Study Area, resources have been assigned in areas ranging from Townships 70 to 80, Ranges 9 to 13W6. Five distinct properties are encompassed within the Study Area and consist of Pouce Coupe, Gordondale, Elmworth North, Elmworth South and Elmworth. The Study Area is further bounded in a northwest-southeast direction by the Deep Basin edge. The geological section studied was divided into the DoigP, BD and Montney stratigraphic units. The Montney was further subdivided into seven intervals, from the top to the base: D5, D4, D3, D2, D1, TSE Valhalla and C.

Contingent and prospective resources have been attributed to Birchcliff's properties in the Pouce Coupe, Gordondale and Elmworth areas. Birchcliff's resources in the Pouce Coupe and Gordondale areas are proximal to Birchcliff's lands to which reserves have been attributed and to the Pouce Coupe Gas Plant, as well as to third party gathering and processing infrastructure. Birchcliff's resources in the Elmworth area are proximal to Birchcliff's lands to which reserves have been attributed and to third party gathering and processing infrastructure.

Birchcliff's average working interest in its gross best estimate contingent resources is 93% and its average working interest in its gross best estimate prospective resources is 97%.

**Project Definition**

Pursuant to NI 51-101, Birchcliff is required to describe the "projects" to which its resources have been attributed. "Project" is defined in the COGE Handbook as "a defined activity, or set of activities that provides the basis for the assessment and classification of resources". Deloitte segregated Birchcliff's Montney/Doig resources into development projects based on areal (property/area) and vertical (play interval) boundaries. The Study Area consisted of three areas with resources, namely: Pouce Coupe, Gordondale and Elmworth. The Montney/Doig formations are comprised of nine individually mapped stratigraphic units: the DoigP, the BD and the Montney D5, D4, D3, D2, D1, TSE and C stratigraphic units.

Stratigraphic units were combined for specific projects if Deloitte believed that a single well could produce from more than one unit at once and both zones have been designated as either prospective or contingent. If Birchcliff did not hold rights to all of the combined units across all of its land, they were classified as their own separate project for those particular sections. For details regarding Birchcliff's particular projects, see *"Contingent Resources"* and *"Prospective Resources"* in this Appendix A.

**Summary of Discovered and Undiscovered Resources**

The following table sets forth Birchcliff's gross best estimate contingent resources, prospective resources, total discovered and undiscovered PIIP and total PIIP at December 31, 2019 and December 31, 2018:

*Summary of Discovered and Undiscovered Resources*

| | Volumes | | |
|---|---|---|---|
| **Resource Class** | **December 31, 2019 *(Bcfe)*** | **December 31, 2018 *(Bcfe)*** | **Change from December 31, 2018** |
| Contingent Resources | 14,878.6 | 13,146.9 | 13% |
| Total Discovered PIIP | 46,350.9 | 41,499.7 | 12% |
| Prospective Resources | 16,964.4 | 14,548.7 | 17% |
| Total Undiscovered PIIP | 33,194.8 | 29,028.6 | 14% |
| Total PIIP | 79,545.7 | 70,528.2 | 13% |

Birchcliff's contingent and prospective resources, total discovered and undiscovered PIIP and total PIIP at December 31, 2019 all increased as compared to December 31, 2018, primarily as a result of the increase in mineral land rights held by Birchcliff as at December 31, 2019 and development in the area by Birchcliff and offsetting competitors.

The following table sets forth Birchcliff's gross volumes for all resources, both discovered and undiscovered, at December 31, 2019:

*Summary of Reserves and Resources*

| Resource Class | | | Raw/Sales | Reserves and Resource Volumes (Bcfe)[1] Low Estimate Case | Best Estimate Case | High Estimate Case |
|---|---|---|---|---|---|---|
| Discovered | | Cumulative Production[2] | Sales | 1,149.6 | 1,149.6 | 1,149.6 |
| | | Remaining Reserves[2][3][4] | Sales | 4,297.5 | 6,259.1 | 7,997.0 |
| | | Total Commercial Recoverable[2] | Sales | 5,477.1 | 7,408.7 | 9,146.6 |
| | | Surface and Process Loss[5] | Raw | 280.4 | 387.3 | 464.7 |
| | | Total Commercial | Raw | 5,727.6 | 7,796.1 | 9,611.3 |
| | | **Contingent Resources[2]** | Sales | **11,427.6** | **14,878.6** | **20,545.3** |
| | | Development Pending[2] | Sales | 7,850.7 | 10,043.2 | 13,582.1 |
| | | Development On Hold[2] | Sales | 3,198.4 | 4,288.2 | 5,872.6 |
| | | Development Unclarified[2] | Sales | 190.8 | 296.3 | 752.8 |
| | | Development Not Viable[2] | Sales | 187.8 | 251.0 | 337.8 |
| | | Surface and Process Loss | Raw | 863.2 | 1,153.3 | 1,557.3 |
| | | Unrecoverable | Raw | 23,057.8 | 22,522.9 | 20,614.6 |
| | | Total Sub-Commercial | Raw | 35,348.6 | 38,554.8 | 42,717.2 |
| | **TOTAL DISCOVERED PIIP** | | Raw | **41,076.2** | **46,350.9** | **52,328.5** |
| Undiscovered | | **Prospective Resources[2]** | Sales | **12,209.1** | **16,964.4** | **23,671.1** |
| | | Prospect[2][6] | Sales | 12,209.1 | 16,964.4 | 23,671.1 |
| | | Surface and Process Loss | Raw | 558.8 | 765.7 | 1,054.7 |
| | | Unrecoverable | Raw | 15,393.7 | 15,464.6 | 14,406.4 |
| | **TOTAL UNDISCOVERED PIIP** | | Raw | **28,161.6** | **33,194.8** | **39,132.2** |
| **TOTAL PIIP** | | | Raw | **69,237.8** | **79,545.7** | **91,460.7** |

(1) The volumes presented in the table above, other than cumulative production and reserves, have been presented on an unrisked basis, meaning that they have not been adjusted for the chance of commerciality.

(2) Sales gas, oil and NGLs volumes were combined at a ratio of 1 bbl: 6 Mcfe.

(3) Includes reserves assigned to both vertical and horizontal Montney/Doig wells in the Consolidated Reserves Report. Birchcliff has ongoing projects to drill horizontal wells targeting the Montney. This has resulted in some of the areas in the Study Area already having been assigned undeveloped reserves by Birchcliff's independent qualified reserves evaluators. The reserves assignments as of the effective date of the 2019 Resource Assessment have been subtracted from the resource estimates. Proved, probable and possible reserves as contained in the Consolidated Reserves Report are included in the above table for completeness; however, reserves were not the focus of the 2019 Resource Assessment. The low estimate case includes the estimate of proved reserves contained in the Consolidated Reserves Report, the best estimate case includes the estimate of proved plus probable reserves contained in the Consolidated Reserves Report and the high estimate case includes the estimate of proved plus probable plus possible reserves contained in the Consolidated Reserves Report. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(4) The remaining reserves presented are technical reserves and have not been reduced for the economic limit.

(5) Includes surface and process loss attributed to cumulative production and remaining reserves volumes.

(6) All of Birchcliff's prospective resources were sub-classified into the project maturity sub-class of "prospect". See *"Prospective Resources – Project Maturity Sub-classes for Prospective Resources"* in this Appendix A.

## Contingent Resources

### *Summary of Risked Contingent Resources*

The following table sets forth Birchcliff's best estimate (2C) risked contingent resources by product type at December 31, 2019, estimated using the IQRE Price Forecast:

*Summary of Risked Contingent Resources – 2C*
*at December 31, 2019*
*(Forecast Prices and Costs)*

| **Resources** | **Shale Gas[2]** | | **NGLs** | | **Light Crude and Medium Crude Oil** | | **Total** | |
|---|---|---|---|---|---|---|---|---|
| **Project Maturity Sub-class[1]** | ***Gross[3] (Bcf)*** | ***Net[4] (Bcf)*** | ***Gross[3] (MMbbls)*** | ***Net[4] (MMbbls)*** | ***Gross[3] (MMbbls)*** | ***Net[4] (MMbbls)*** | ***Gross[3] (Bcfe)*** | ***Net[4] (Bcfe)*** |
| Development Pending | 7,500.0 | 6,563.4 | 176.4 | 129.7 | 4.1 | 3.2 | 8,582.9 | 7,360.8 |
| Development On Hold | 2,570.8 | N/A | 70.7 | N/A | 0.0 | N/A | 2,995.0 | N/A |
| Development Unclarified | 109.6 | N/A | 1.2 | N/A | 0.3 | N/A | 118.5 | N/A |
| Development Not Viable | 40.3 | N/A | 1.6 | N/A | 0.0 | N/A | 50.2 | N/A |

(1) For a description of the project maturity sub-classes applicable to the Corporation's contingent resources, see *"Contingent Resources – Project Maturity Sub-classes for Contingent Resources"* in this Appendix A.

(2) The associated solution gas from the assigned oil resource locations has been included in the shale gas product type.

(3) Gross risked contingent resources are technical volumes.

(4) Net volumes presented in the table above are economic volumes using clarified cut-off date criteria in the COGE Handbook. Economics were not evaluated for Birchcliff's development on hold, development unclarified or development not viable contingent resources. Accordingly, no information is available for royalties and a net number cannot be determined.

At December 31, 2019, Birchcliff had gross best estimate contingent resources of 14,878.6 Bcfe (unrisked before adjusting for the chance of commerciality) and gross best estimate contingent resources of 11,746.6 Bcfe (risked after adjusting for the chance of commerciality).

### *Summary of the Risked Net Present Value of Development Pending Contingent Resources*

The following table sets forth the net present value of future net revenue of Birchcliff's best estimate risked contingent resources in the development pending project maturity sub-class at December 31, 2019, estimated using the IQRE Price Forecast:

*Summary of Risked Net Present Value of Future Net Revenue of Development Pending Contingent Resources*
*at December 31, 2019*
*(Forecast Prices and Costs)*

| | **Risked Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)[1]** | | | | |
|---|---|---|---|---|---|
| **Resources Project Maturity Sub-class** | **0** ***(MM$)*** | **5** ***(MM$)*** | **10** ***(MM$)*** | **15** ***(MM$)*** | **20** ***(MM$)*** |
| Contingent (2C) Development Pending | 20,646.9 | 4,683.1 | 1,257.5 | 356.0 | 81.3 |

(1) The net present value of future net revenue attributable to the Corporation's development pending contingent resources is based on the IQRE Price Forecast and is determined before provision for interest, debt servicing and general and administrative expense and after the deduction of royalties, operating costs, development costs and abandonment and reclamation costs.

**An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Corporation proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the estimate of risked net present value of future net revenue will be realized.**

The IQRE Price Forecast is summarized in the Annual Information Form under the heading *"Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions – Forecast Prices Used in Estimates".*

***Chance of Commerciality of Contingent Resources***

As all contingent resources are considered to be discovered, the chance of commerciality is equal to the chance of development for contingent resources. "Chance of development" is the estimated probability that, once discovered, a known accumulation will be commercially developed. Deloitte referred to the five requirements outlined in the COGE Handbook for commerciality when estimating the chance of development for Birchcliff's contingent resource projects. These requirements include: (i) the project is economically viable; (ii) there is a market for the forecast sales quantities of production required to justify development; (iii) the necessary production, transportation facilities and access to infrastructure are available or can be made available; (iv) the regulatory, environmental, societal and political conditions will allow for the actual implementation of the recovery project being evaluated; and (v) all required internal and external approvals are forthcoming. Evidence of this may include items such as signed contracts, budget approvals and approvals for expenditures.

Evaluation of each of these items are qualitative in nature. Deloitte stated that it had no reason to believe that requirements (ii), (iv) or (v) are significantly better or worse when comparing development pending projects against each other. The most tangible distinction between development pending projects was requirement (iii) (the necessary production, transportation facilities and access to infrastructure are available or can be made available) and therefore served as the basis for selecting the chance of commerciality for these projects. The guidance in the COGE Handbook recommends a high chance of success should be at minimum 80%. Out of the Pouce Coupe, Gordondale and Elmworth properties, infrastructure in the Pouce Coupe and Gordondale properties is the most developed. Plant expansions and sizeable investment committed to pipeline infrastructure are supported in the Deloitte Reserves Report. For this reason, all development pending Pouce Coupe projects were assigned the highest chance of commerciality of 90% by Deloitte.

The Gordondale area has infrastructure and maintenance costs forecast in the McDaniel Reserves Report. Deloitte has assigned a 90% chance of commerciality for the development pending D1/TSE gas and D2 oil, gas and transition projects based on the existing infrastructure in the area. For the development pending BD/D5/DoigP, BD/DoigP only and D4 projects, Deloitte has assigned an 80% chance of commerciality to such projects due to the lack of development on these zones in the area to date. In addition, to account for low pressure lands within the DoigP, BD and D5 Montney zones on the Gordondale property, Deloitte has risked the associated projects by assigning lower recoverable volumes on a per location basis.

Projects in the Elmworth area have little to no infrastructure investment forecast in the Deloitte Reserves Report. All development pending Elmworth projects were assigned an 80% chance of commerciality as these projects are forecast to be processed through a natural gas processing plant assumed by Deloitte in its assessment (the "**Assumed Elmworth Plant**") affecting certainty in operating costs and the economics of the project.

The chance of development is expected to decrease for other maturity sub-classes based on requirements (i) and (iii). The uncertainty associated with these requirements typically increases in the development on hold, development unclarified and development not viable sub-classes. Deloitte modelled this by estimating the chance of commerciality values to be 60% for development on hold, 40% for development unclarified and 20% for development not viable projects. These projects have lower chances of commerciality as a result of the priority of development being given to other contingent projects, due to distance to infrastructure and less desirable economics. The estimated contingent resources and associated net present values are simply multiplied by the chance of commerciality in the economic software to result in risked volumes and net present values.

***Project Maturity Sub-classes for Contingent Resources***

Contingent resources can be sub-classified based on their project maturity sub-class. The project maturity sub-classes for contingent resources are "development pending", "development on hold", "development unclarified" or "development not viable", all as defined in the COGE Handbook. "Development pending" is when resolution of the final conditions for development is being actively pursued (high chance of development). "Development on hold" is when there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. "Development unclarified" is when the evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties. "Development not viable" is when no further data acquisition or evaluation is currently planned and hence there is a low chance of development.

Approximately 67.5% of Birchcliff's gross unrisked best estimate case contingent resources were sub-classified as development pending, 28.8% were sub-classified as development on hold, 2.0% were sub-classified as development unclarified and 1.7% were sub-classified as development not viable. Although Birchcliff's development unclarified and development not viable projects do not represent a material amount of Birchcliff's estimated contingent resources, the Corporation has chosen to disclose the estimated volumes of such resources for completeness.

Birchcliff's contingent resources were sub-classified by Deloitte as development pending, development on hold, development not viable or development unclarified as described below.

*Development Pending*

Each contingent resource project was sub-classified as development pending if the contingent resource project is currently economic and satisfies the COGE Handbook requirements of commerciality in that:

(i) there is an expected market for the sale of forecast production volumes from the project;

(ii) the necessary production and transportation facilities are expected to be available in the relevant time frame, as a result of Birchcliff's long range forward planning;

(iii) there is no reasonable expectation that legal, contractual, environmental, governmental and other social and economic concerns will preclude the development of the project since project development is in the same area and follows the same business model that Birchcliff has been implementing over the last 12 years with respect to the development of its Montney/Doig Resource Play;

(iv) there is a reasonable expectation that internal and external approvals will be forthcoming in a timely manner since project development is in the same area and follows the same business model that Birchcliff has been implementing over the last 12 years with respect to the development of its Montney/Doig Resource Play; and

(v) Birchcliff intends to move forward with the development of the project within a reasonable time frame as it moves towards completion of the development of its reserves.

*Development On Hold*

Each contingent resource project was sub-classified as development on hold if it could be economic at some point in the future. In addition, some contingent resource projects satisfied the conditions for development pending; however, if the Corporation indicated that it currently had no intention of developing these resources within a reasonable timeframe, the project was sub-classified as development on hold. This applied to two of the Corporation's projects in each of Pouce Coupe and Gordondale (the C development on hold and BD/D5/DoigP development on hold projects) and two of the Corporation's projects in the Elmworth North area (the BD/D5/DoigP on hold and the BD/DoigP only on hold projects). See *"Contingent Resources – Birchcliff's Contingent Resource Projects".*

*Development Unclarified*

Contingent resource projects with limited information and uncertain economics were sub-classified as development unclarified. These projects will require further examination in the future to move into a different project maturity sub-class.

*Development Not Viable*

Contingent resource projects were sub-classified as development not viable when their contingent volumes had a low chance of development due to no further plans for data acquisition or evaluation. These projects are unlikely to ever be economic. The reclassification from development not viable to development on hold can only occur if prices increase beyond the current IQRE Price Forecast assuming the same project economics.

*Economic Status Criteria of Contingent Resource Project Maturity Sub-classes*

For purposes of addressing the project economic criterion of each of the project maturity sub-classes, Deloitte applied the following criteria:

(i) each resource project was considered currently economic if the project had a positive NPV discounted at a rate of 10% (before income taxes) using the IQRE Price Forecast with current capital and operating expense assumptions;

(ii) Deloitte considered that a resource project could be economic at some point in the future if the project had a positive undiscounted NPV (before income taxes) using the IQRE Price Forecast that was increased by 20%; and

(iii) Deloitte considered that a resource project was unlikely to ever be economic if the project did not have a positive undiscounted NPV (before income taxes) using the IQRE Price Forecast that was increased by 20%.

***Economic Classification of Contingent Resources***

Contingent resource estimates should have sufficient economic analysis to sub-classify the resource as either economic or sub-economic under economic conditions that are the same as those used for reporting reserves. The appropriate level of economic evaluation will depend on the project status and maturity. Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of production, capital and operating costs, commodity prices and inflation. Sub-economic contingent resources are those contingent resources that are not currently economically recoverable based on specific forecasts of production, capital and operating costs, commodity prices and inflation. Each contingent resource project was sub-classified by Deloitte as economic if the project had a positive NPV discounted at a rate of 10% (before income taxes) using the IQRE Price Forecast with current capital and operating expense assumptions. Each contingent resource project that did not meet this economic hurdle was sub-classified as sub-economic. Where evaluations are incomplete such that it is premature to identify the economic viability of a project, the economic status was sub-classified as undetermined.

All of Birchcliff's development pending projects were sub-classified as economic and Birchcliff's development not viable and development on hold projects were sub-classified as sub-economic. Development unclarified projects were sub-classified as economic status undetermined.

Approximately 67.5% of Birchcliff's unrisked best estimate contingent resources were sub-classified as economic contingent resources, 30.5% were sub-classified as sub-economic contingent resources and 2.0% were sub-classified as economic status undetermined.

***Birchcliff's Contingent Resource Projects***

The following table sets forth for each of Birchcliff's contingent resource projects, the project maturity sub-class, the chance of commerciality, the economic status, the estimated total cost to achieve commercial production, the timeline of each project and the estimated date of first commercial production and the number of resource locations:

| Project | | Project Maturity Sub-class | Chance of Commer-ciality(1) | Economic Status | Estimated Total Cost to Achieve Commercial Production (MM$)(2) | Timeline of Project and Estimated Date of First Commercial Production(2) | Resource Locations(2)(5) |
|---|---|---|---|---|---|---|---|
| *Pouce Coupe Area* | | | | | | | |
| Pouce Coupe | BD/D5/DoigP | Development Pending | 90% | Economic | | 2025 | 189 |
| Pouce Coupe | BD/D5/DoigP On Hold | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Pouce Coupe | BD/DoigP Only(6) | Development Pending | 90% | Economic | | 2030 | 79 |
| Pouce Coupe | D5 Only(6) | Development Pending | 90% | Economic | | 2047 | 51 |
| Pouce Coupe | D4 | Development Pending | 90% | Economic | | 2027 | 373 |
| Pouce Coupe | D3 | Development Unclarified | 40% | Undetermined | | N/A | N/A |
| Pouce Coupe | D2 | Development Pending | 90% | Economic | | 2039 | 230 |
| Pouce Coupe | D1/TSE | Development Pending | 90% | Economic | | 2025 | 213 |
| Pouce Coupe | C Dev Pending | Development Pending | 90% | Economic | | 2042 | 585 |
| Pouce Coupe | C Dev On Hold | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Pouce Coupe | Plant & Infrastructure Capital(7) | Development Pending | 90% | Economic | | 2025 | N/A |
| | | | | **Total** | **0.0(3)** | **Total** | **1,720** |
| *Gordondale Area* | | | | | | | |
| Gordondale | BD/D5/DoigP | Development Pending | 80% | Economic | | 2029 | 151 |
| Gordondale | BD/D5/DoigP On Hold | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Gordondale | BD/DoigP Only(6) | Development Pending | 80% | Economic | | 2032 | 7 |
| Gordondale | BD/DoigP Only On Hold(6) | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Gordondale | D5 Only(6) | Development Not Viable | 20% | Sub-Economic | | N/A | N/A |
| Gordondale | D4 | Development Pending | 80% | Economic | 6.3(3) | 2039 | 53 |
| Gordondale | D2 Oil(8) | Development Pending | 90% | Economic | | 2029 | 25 |
| Gordondale | D2 Transition | Development Pending | 90% | Economic | | 2036 | 23 |
| Gordondale | D2 Gas | Development Pending | 90% | Economic | | 2038 | 69 |
| Gordondale | D1/TSE Oil(8) | Development Unclarified | 40% | Undetermined | | N/A | N/A |
| Gordondale | D1/TSE Gas | Development Pending | 90% | Economic | | 2029 | 8 |
| Gordondale | C | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Gordondale | Plant & Infrastructure Capital(7) | Development Pending | 90% | Economic | | 2029 | N/A |
| | | | | **Total** | **6.3(3)** | **Total** | **336** |
| *Elmworth Area* | | | | | | | |
| Elmworth South | D5 Only | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Elmworth South | D4 | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Elmworth South | D3 | Development Not Viable | 20% | Sub-Economic | | N/A | N/A |
| Elmworth South | D2 | Development Not Viable | 20% | Sub-Economic | | N/A | N/A |
| Elmworth South | D1 | Development Not Viable | 20% | Sub-Economic | | N/A | N/A |
| Elmworth North | BD/D5/DoigP Pending | Development Pending | 80% | Economic | 5.7(4) | 2027 | 87 |
| Elmworth North | BD/D5/DoigP On Hold | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Elmworth North | BD/DoigP Only Pending(6) | Development Pending | 80% | Economic | | 2032 | 24 |
| Elmworth North | BD/DoigP Only On Hold(6) | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Elmworth North | D5 Only(6) | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Elmworth North | D4 | Development Pending | 80% | Economic | | 2029 | 126 |
| Elmworth North | D2 | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Elmworth North | D1 | Development Not Viable | 20% | Sub-Economic | | N/A | N/A |
| Elmworth | D1 | Development On Hold | 60% | Sub-Economic | | N/A | N/A |
| Elmworth | Plant & Infrastructure Capital(7) | Development Pending | 80% | Economic | 76.2(4) | 2027 | N/A |
| | | | | **Total** | **81.9(4)** | **Total** | **237** |
| | | | | **GRAND TOTAL** | **88.2** | **GRAND TOTAL** | **2,293** |

(1) See *"Contingent Resources – Chance of Commerciality of Contingent Resources"* in this Appendix A for information regarding the process employed by Deloitte to risk Birchcliff's contingent resources.

(2) With respect to the estimated total cost to achieve commercial production, the costs set forth in the table above represent Birchcliff's working interest portion (inflated) of the capital required to achieve initial commercial production for the project area, as discussed in further detail herein. With respect to the timelines of projects and the estimated date of first commercial production, timelines are based on the development plan that was used by Deloitte in the 2019 Resource Assessment and reflect the expected dates that further drilling of those resource projects will first occur under such plan. Development plans were only created for those contingent resources sub-classified as development pending. As no development plans were created for contingent resources in the development on hold, development unclarified or development not viable project maturity sub-classes, there is insufficient information to determine the estimated total cost to achieve commercial production, the timeline of the project or the number of resource locations.

(3) With respect to Birchcliff's development pending projects in the Pouce Coupe area and the Gordondale area (other than the D4 project), there are no costs to achieve commercial production, as the necessary infrastructure is expected to be in place as a result of the development of the Corporation's existing commercial projects. With respect to the D4 project in the Gordondale area, the estimated costs are approximately $6.3 million which represents the risked cost of the first well in that interval that would be necessary for Birchcliff to achieve commercial production in that interval.

(4) The costs to achieve commercial production represent the required initial facility capital for the Elmworth area and represent all projects in the project area. With respect to Birchcliff's development pending projects in the Elmworth area (other than the BD/D5/DoigP project and Facility & Infrastructure capital), there are no costs to achieve commercial production, as the necessary infrastructure is expected to be in place as a result of the development of the Corporation's existing commercial projects and the Assumed Elmworth Plant and infrastructure. With respect to the BD/D5/DoigP project in the Elmworth North area, the estimated cost is approximately $5.7 million, which represents the risked cost of the first well in that interval that would be necessary for Birchcliff to achieve commercial production in that interval.

(5) Resource locations represent the number of wells forecast to be drilled under the development plan for development pending projects.

(6) Birchcliff does not hold rights to all of the combined stratigraphic units within this area so this project was created.

(7) Plant and infrastructure projects consist of facility developments and the associated costs required to develop resources according to the modeled development plan. Such projects are further described under the heading *"Contingent Resources – Development Plans for Development Pending Projects"* and include new major pipelines, new plant capacities, increases of plant capacities and sustaining pipeline and compression projects.

(8) Sections include oil volumes, solution gas, free gas and sorbed gas.

The total cost to achieve commercial production for all projects disclosed in the table above is estimated to be $88.2 million. The total cost to achieve commercial production only includes the capital required to achieve initial commercial production for the project area (for example, required facility and pipeline capital) and does not represent the total capital required to develop the entire project. The total capital required to fully develop the projects set forth in the table above (including total costs to achieve commercial production and total sustaining capital) is estimated to be approximately $13,832.3 million (undiscounted) as follows: (i) Pouce Coupe Area: $10,173.4 million; (ii) Gordondale Area: $1,799.7 million; and (iii) Elmworth Area: $1,859.2 million. Total capital amounts represent Birchcliff's working interest portion (inflated).

The recovery technology for each contingent resource project described above is multi-fracture horizontal wells, which is considered an established technology under the COGE Handbook. All of the contingent resource projects described above are based on Level II (pre-development) studies as per the COGE Handbook.

***Development Plans for Development Pending Projects***

*Overview*

Development plans were created for those projects sub-classified as development pending. Such plans were determined by Deloitte and are consistent with the guidance and input provided by Birchcliff. Deloitte has modelled what is considered a reasonable development plan for development pending contingent resources. In order to create a development schedule for each project, Deloitte utilized an internally built development planning tool. The tool automated the field development plan based on various configurable inputs and constraints while maximizing NPV discounted at a rate of 10% (before income taxes). In addition, unique constraints were applied to each of the facilities assumed by Deloitte in its development plans which were modelled into the development planning tool and the optimal drilling schedule for each plant was calculated.

The uncertainty relating to the development of each of the development pending projects primarily relates to the timing and corporate sanctioning for the development of these resources. Deloitte has forecast development to begin in 2025. There can be no certainty that any of the projects described herein will be developed on the timelines discussed herein. Development of the projects is dependent on a number of contingencies as further described herein, as well as numerous risk factors and uncertainties.

*Projects in the Pouce Coupe Area*

All of Birchcliff's contingent development pending projects in the Pouce Coupe area (excluding the plant and infrastructure capital project) were assumed by Deloitte to produce to the Pouce Coupe Gas Plant. In determining the development plans for such projects, Deloitte relied on the following assumptions relating to the Pouce Coupe Gas Plant:

- The maximum plant capacity will be increased to 660 MMcf/d in October 2023, which increases to 740 MMcf/d in October 2025 and 820 MMcf/d in October 2026.

- The maximum number of resource locations (wells) drilled per year cannot exceed 100 for the life of the resource development.

- The maximum resource locations for each project cannot be exceeded.

For these projects, the proposed resource development plans contemplate that the drilling of the 1,720 resource locations identified in the table above will take place over 28 years from 2025 to 2052. The plant and infrastructure capital is for assumed plant expansions (forecast in 2025 and 2026), sustaining existing pipelines (forecast to be incurred from 2027 to 2052) and additional compression support (forecast to be incurred from 2053 to 2057).

*Projects in the Gordondale Area*

All of Birchcliff's contingent development pending projects in the Gordondale area (excluding the plant and infrastructure capital project) were assumed by Deloitte to produce to either the Gordondale Gas Plant or an assumed shallow-cut expansion to the existing Gordondale Gas Plant (the "**Assumed Shallow-Cut Plant**"). A portion of the BD/D5/DoigP project was forecast to be processed through the Assumed Shallow-Cut Plant and the remaining development pending projects were forecast to be processed through the Gordondale Gas Plant. In determining the development plans for such projects, Deloitte relied on the following assumptions for the Gordondale Gas Plant and the Assumed Shallow-Cut Plant:

- The maximum plant capacity for the Gordondale Gas Plant will remain at 120 MMcf/d.

- The capacity of the Assumed Shallow-Cut Plant will be 30 MMcf/d.

- The maximum number of resource locations drilled per year cannot exceed 35 for the life of the resource development.

- The maximum resource locations for each project cannot be exceeded.

For these projects, the proposed resource development plans contemplate that the drilling of the 336 resource locations identified in the table above will take place over 20 years from 2029 to 2048. The plant and infrastructure capital is for pipeline infrastructure (forecast to be incurred from 2029 to 2048) and additional compression support (forecast to be incurred from 2049 to 2053).

*Projects in the Elmworth Area*

All of Birchcliff's contingent development pending projects in the Elmworth and Elmworth North areas (excluding the plant and infrastructure capital project) were assumed by Deloitte to produce to the Assumed Elmworth Plant. In determining the development plans for such projects, Deloitte relied on the following assumptions for the Assumed Elmworth Plant:

- The maximum plant capacity will be 40 MMcf/d in 2027, which increases to 80 MMcf/d in 2029 and 120 MMcf/d in 2030.

- The maximum number of resource locations drilled per year cannot exceed 35 for the life of the resource development.

- The maximum resource locations for each project cannot be exceeded.

For these projects, the proposed resource development plans contemplate that the drilling of the 237 resource locations identified in the table above will take place over 22 years from 2027 to 2048. The plant and infrastructure capital is for the Assumed Elmworth Plant, a sales pipeline and a trunk pipeline (forecast to be incurred in 2027), gas plant expansions (forecast to be incurred in 2029 and 2030), additional pipeline infrastructure (forecast to be incurred from 2031 to 2048) and additional compression support (forecast to be incurred from 2049 to 2053).

***Contingencies***

Contingent resources are not currently considered to be commercially recoverable due to one or more contingencies. A contingency is a condition that must be satisfied for a portion of contingent resources to be classified as reserves that is specific to the project being evaluated and expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal environmental, political and regulatory matters or a lack of markets.

*Development Pending Project Maturity Sub-classes*

The development of each of Birchcliff's development pending projects is contingent upon:

- Birchcliff obtaining the necessary internal approvals for the expenditure of capital on the development project; and
- Birchcliff initiating field development in an appropriate timeframe.

These contingencies are expected to be resolved as a result of Birchcliff developing and implementing plans over time in an orderly fashion.

*Development on Hold and Development Not Viable Project Maturity Sub-classes*

In addition to the contingencies described above for Birchcliff's development pending projects, the development of each of Birchcliff's development on hold projects is also contingent upon the ability of the project to compete with projects which have a greater chance of commerciality for finite development capital and resources and the strategic considerations relating to the scale and efficiencies of these projects. These contingencies are expected to be resolved over time through Birchcliff's orderly clarification of sanctioned corporate plans through its five-year plan and annual budget processes.

*Development Unclarified Project Maturity Sub-classes*

In addition to the contingencies described above for Birchcliff's development pending projects, the development of each of Birchcliff's development unclarified projects is also contingent upon clarifying uncertainties in the economic evaluation and production forecasts consistent with an early stage of development for the project. These contingencies are expected to be resolved by the continued economic evaluation of future production and development.

*Projects Involving Expanded or New Facilities/Infrastructure*

In addition to the contingencies described above for Birchcliff's development pending projects, all of Birchcliff's contingent resource projects are contingent upon the development of the facilities/infrastructure described under the heading *"Contingent Resources – Development Plans for Development Pending Projects"*. These additional contingencies are expected to be resolved by the sanctioned approval and construction of the described facilities.

*Projects Producing Sour Gas*

In addition to the contingencies described above for Birchcliff's development pending projects, the development of each of Birchcliff's contingent resource projects expected to deliver volumes of sour gas ($H_2S$) have the following additional contingencies:

- Birchcliff obtaining the necessary regulatory approvals;
- the design, construction and maintenance by Birchcliff of sour gas disposal wells and facilities; and

- Birchcliff maintaining social licence for the development of the project with surface landholders, First Nations and other stakeholders.

These contingencies apply to all projects in the Elmworth and Elmworth North areas. These additional contingencies can be resolved by Birchcliff implementing best practices in these operations and by Birchcliff effectively engaging with regulatory authorities, surface landholders, First Nations and other stakeholders.

*Full Field Development*

The complete full field development of each of Birchcliff's contingent resource projects is contingent upon:

- Birchcliff continuing proactive effective long range planning and design (surface and sub-surface) of all future development wells involved in the project; and
- Birchcliff obtaining the necessary regulatory approvals, particularly related to downspacing in the Montney.

These additional contingencies are expected to be resolved by continuing to implement development consistent with full field development plans and effectively engaging with regulatory authorities.

**Prospective Resources**

***Summary of Risked Prospective Resources***

The following table sets forth Birchcliff's best estimate risked prospective resources by product type at December 31, 2019:

*Summary of Risked Prospective Resources – Best Estimate*
*at December 31, 2019*

| | Shale Gas | | NGLs | | Light Crude Oil and Medium Crude Oil | | Total | |
|---|---|---|---|---|---|---|---|---|
| **Resources** | ***Gross (Bcf)*** | ***Net[(2)] (Bcf)*** | ***Gross (MMbbls)*** | ***Net[(2)] (MMbbls)*** | ***Gross (MMbbls)*** | ***Net[(2)] (MMbbls)*** | ***Gross (Bcfe)*** | ***Net[(2)] (Bcfe)*** |
| Prospective (Best Estimate)[(1)(2)] | 5,381.8 | N/A | 101.5 | N/A | 0.2 | N/A | 5,991.7 | N/A |

(1) All of Birchcliff's prospective resources are sub-classified into the project maturity sub-class of "prospect". For a description of the project maturity sub-classes applicable to prospective resources, see *"Prospective Resources – Project Maturity Sub-classes for Prospective Resources"* in this Appendix A. The numbers in the table above are technical volumes.

(2) Numbers are not applicable because economics were not evaluated for Birchcliff's prospective resources. As economics were not evaluated, no information is available for royalties and a net number cannot be determined.

At December 31, 2019, Birchcliff had gross best estimate prospective resources of 16,964.4 Bcfe (unrisked before adjusting for the chance of commerciality) and 5,991.7 Bcfe (risked after adjusting for the chance of commerciality).

***Chance of Commerciality of Prospective Resources***

The chance of commerciality for prospective resources is equal to the product of the chance of discovery and the chance of development. "Chance of discovery" is the estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum. "Chance of development" is the estimated probability that, once discovered, a known accumulation will be commercially developed. The chance of discovery associated with Birchcliff's prospective resource volumes has been estimated by Deloitte to be 90% for all projects with a chance of development of either 40% or 30%, resulting in an overall chance of commerciality of 36% or 27%.

The chance of discovery was estimated to be 90% due to the relatively high geological certainty of encountering the specific zone in each project and area. Birchcliff and nearby industry competitors have and continue to refine the geological model within and outside of the Study Area. Additionally, Deloitte's four mile radius boundary in conjunction with geological mapping and the exploration success of Birchcliff and nearby industry competitors with similar resources and under varying conditions indicates that the resource play is well understood from an exploratory viewpoint.

The chance of development was estimated to be 40% for projects in high pressure zones due to the priority given to the further development of the existing plays and the contingent projects, the greater distance to existing reserves and the greater distance to existing infrastructure. This also takes into account Birchcliff's high working interest and operatorship of its assets as the Corporation is not subject to the priorities of working interest partners for such assets. For prospective projects within the low-pressure boundary, the chance of development was estimated to be 30%. The factor was decreased as individual well deliverability will most likely be an issue in the low-pressure zones during the development of these projects.

***Project Maturity Sub-classes for Prospective Resources***

Prospective resources can be sub-classified based on their project maturity sub-class. The project maturity sub-classes for prospective resources are "prospect", "lead" and "play", all as defined in the COGE Handbook. A "prospect" is defined as a potential accumulation within a play that is sufficiently well defined to represent a viable drilling target. A "lead" is defined as a potential accumulation within a play that requires more data acquisition and/or evaluation in order to be sub-classified as a prospect. A "play" is defined as a family of geologically similar fields, discoveries, prospects and leads. 100% of Birchcliff's prospective resources were sub-classified as prospects.

***Birchcliff's Prospective Resource Projects***

The following is a description of each of Birchcliff's prospective resource projects:

| Project | | Chance of Discovery | Chance of Development | Chance of Commerciality |
|---|---|---|---|---|
| Pouce Coupe | D4 | 90% | 40% | 36% |
| Pouce Coupe | D3 | 90% | 40% | 36% |
| Pouce Coupe | D2 | 90% | 40% | 36% |
| Gordondale | BD/D5/DoigP(1) | 90% | 30% | 27% |
| Gordondale | BD/DoigP Only(1)(2) | 90% | 30% | 27% |
| Gordondale | D5 Only(1)(2) | 90% | 30% | 27% |
| Gordondale | D4(1) | 90% | 30% | 27% |
| Gordondale | D3(1) | 90% | 30% | 27% |
| Gordondale | D2 Oil | 90% | 40% | 36% |
| Gordondale | D2 Gas | 90% | 40% | 36% |
| Gordondale | D1/TSE | 90% | 40% | 36% |
| Gordondale | C | 90% | 40% | 36% |
| Elmworth | DoigP | 90% | 40% | 36% |
| Elmworth | BD | 90% | 40% | 36% |
| Elmworth | D5 | 90% | 40% | 36% |
| Elmworth | D4 | 90% | 40% | 36% |
| Elmworth | D3 | 90% | 40% | 36% |
| Elmworth | D2 | 90% | 40% | 36% |
| Elmworth | D1 | 90% | 40% | 36% |
| Elmworth | TSE | 90% | 40% | 36% |
| Elmworth | C | 90% | 40% | 36% |
| Elmworth North | BD/D5/DoigP | 90% | 40% | 36% |
| Elmworth North | BD/DoigP Only(2) | 90% | 40% | 36% |
| Elmworth North | D5 Only(2) | 90% | 40% | 36% |
| Elmworth North | D4 | 90% | 40% | 36% |
| Elmworth North | D3 | 90% | 40% | 36% |
| Elmworth North | D2 | 90% | 40% | 36% |
| Elmworth North | D1 | 90% | 40% | 36% |
| Elmworth North | TSE | 90% | 40% | 36% |
| Elmworth North | C | 90% | 40% | 36% |
| Elmworth South | BD/DoigP Only(2) | 90% | 40% | 36% |
| Elmworth South | D5 Only | 90% | 40% | 36% |
| Elmworth South | D4 | 90% | 40% | 36% |
| Elmworth South | D3 | 90% | 40% | 36% |
| Elmworth South | D2 | 90% | 40% | 36% |

| Project | | Chance of Discovery | Chance of Development | Chance of Commerciality |
|---|---|---|---|---|
| Elmworth South | D1 | 90% | 40% | 36% |
| Elmworth South | TSE | 90% | 40% | 36% |
| Elmworth South | C | 90% | 40% | 36% |

(1) These projects have a lower chance of development assigned as they fall within the low-pressure boundary.

(2) Birchcliff does not hold rights to all of the combined stratigraphic units within this area so this project was created.

The recovery technology for each project described above is multi-fracture horizontal wells which is considered an established technology under the COGE Handbook. All of the projects described above are based on Level II (pre-development) studies as per the COGE Handbook.

**Risk Factors and Uncertainties**

***General***

There are numerous uncertainties inherent in estimating quantities of resources and the future net revenue attributed to the best estimate of the Corporation's development pending contingent resources. The resource and associated future net revenue information for the best estimate of the development pending contingent resources set forth herein are estimates only.

In general, estimates of resources and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate resource recovery, the timing and amount of capital expenditures, marketability of oil, NGLs and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For these reasons, estimates of the resources attributable to any particular group of properties, the classification of such resources based on risk of recovery and estimates of future net revenue associated with resources prepared by different engineers, or by the same engineer at different times, may vary. Birchcliff's actual production, revenue, taxes and development and operating expenditures with respect to its resources will vary from estimates thereof and such variations could be material.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the best estimate of Birchcliff's development pending contingent resources represent the fair market value of those resources. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The estimates of Birchcliff's resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein and variances could be material. With respect to the discovered resources (including contingent resources), there is uncertainty that it will be commercially viable to produce any portion of the resources. With respect to the undiscovered resources (including prospective resources), there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

For further information regarding the risks and uncertainties relating to Birchcliff and its properties to which no reserves have been attributed, see *"Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Properties with No Attributed Reserves"* and *"Risk Factors"* in the Annual Information Form.

***Risk Factors and Uncertainties***

There are numerous factors and uncertainties that affect the anticipated development of the Corporation's resources.

The chances of development for the estimated resources are subject to a number of factors, including overall project economics, the employed recovery technology or technology under development, regulatory and environmental approval, the availability of markets and production facilities and political risk to the development. The Corporation will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil, natural gas and NGLs from its resource properties in the future. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, that the terms will be acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain opportunities, reduce its pace of development or terminate its operations on such properties. An inability of the Corporation to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Corporation's ability to execute its business strategy to develop its prospects.

The significant economic factors that affect the Corporation's future development of its resources are:

- future commodity prices for oil and natural gas (and the Corporation's outlook relating to such prices);
- the future capital costs of drilling, completing, tying in and equipping the wells necessary to develop such lands at the relevant times;
- the future costs of operating wells at the relevant times; and
- the levels of royalties applicable to productions from such lands.

The significant uncertainties that affect the Corporation's development of its resources are:

- the ability of the Corporation to obtain the capital necessary to fund the development of such lands at the relevant times;
- the future drilling and completion results the Corporation achieves in its development activities (e.g. with respect to the development of particular intervals or geographic areas, the uncertainty would be whether the initial drilling and completion results are sufficient to justify the development of such interval or geographic area);
- drilling and completion results achieved by others on lands in proximity to the Corporation's lands;
- transportation and processing infrastructure becoming available in a timeline consistent with proposed development plans;
- the availability of regulatory approvals for development of the lands and the necessary infrastructure; and
- governmental actions and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities.

Significant risk factors specific to Birchcliff and the projects outlined herein include the following:

- Commodity prices have been and are expected to remain volatile. Sustained low prices may compel the Corporation to re-evaluate its development plans and reduce or eliminate various projects with marginal economics. Birchcliff will need to be satisfied that its forecast of future industry and economic conditions and commodity prices prevailing during and after the applicable development project is sufficient to justify proceeding with the development of such project.
- The actual operating and other costs may vary materially from the costs assumed by Deloitte. For example, the operating costs for the Elmworth area assumed by Deloitte were based on the field operating costs for the nearby, analogous Pouce Coupe area. If actual operating or other costs vary materially from those assumed by Deloitte, this would have an impact on the economics of the applicable project and could delay development.
- If the facilities and infrastructure do not expand in the manner and in the time frame assumed by Deloitte, this would have an impact on the development schedules for Birchcliff's resource projects and such projects could be delayed. In addition, the Gordondale Gas Plant is owned, and the Assumed Shallow-Cut Plant will be owned, by a third party which the Corporation does not control.

- The Corporation's development activities are dependent on the availability of equipment, materials (including those needed for fracturing operations) and skilled personnel. Demand for such limited equipment, materials and skilled personnel may affect the availability of such equipment, materials and skilled personnel to the Corporation and may delay the Corporation's development activities. During times of high demand, the costs of such equipment, materials and personnel may increase, resulting in increased costs to the Corporation.

- The implementation of new regulations or the modification of existing regulations regarding hydraulic fracturing, the environment or climate change, including GHG and methane emissions, may have a material adverse impact on the Corporation's ability to develop its resources. Any new laws, regulations or permitting requirements could lead to operational delays, increased operating costs, third party or governmental claims and could increase the Corporation's costs of compliance and doing business. All of the foregoing could delay development.

All of these risks and uncertainties have the potential to delay the development of Birchcliff's resources. On the other hand, uncertainty as to the timing and nature of the evolution of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to the development of such resources.

There are no unusually significant abandonment and reclamation costs associated with the resources.

See *"Industry Conditions"* and *"Risk Factors"* in the Annual Information Form for further information regarding the industry conditions and risk factors applicable to the Corporation.

***Positive and Negative Factors Relevant to the Estimates***

Significant positive factors relevant to the estimates of Birchcliff's resources include:

- Birchcliff's and offsetting competitor wells with production history from the same zones;

- Birchcliff's successful and economic past use of the same drilling and completion techniques are intended to be used by Birchcliff to develop these resources; and

- Birchcliff's strong record of developing similar development projects according to its plans.

Significant negative factors relevant to the estimate of Birchcliff's resources include:

- current limitations in take-away/midstream capacity to deliver the resources to market;

- future plant capacity constraints at third-party processing facilities;

- uncertainty in assumptions about the geometry of hydraulic fracture stimulations and associated recovery factors; and

- low-pressure areas with potential production deliverability issues. This is applicable to the Corporation's D4, D5 only, BD/DoigP only and BD/D5/DoigP contingent resource projects in Gordondale and the Corporation's D3, D4, D5 only, BD/DoigP only and BD/D5/DoigP prospective resource projects in Gordondale.

## APPENDIX B

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

To the Board of Directors of Birchcliff Energy Ltd. (the "**Company**"):

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

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

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

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

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

| | | | Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) | | | |
|---|---|---|---|---|---|---|
| **Independent Qualified Reserves Evaluator or Auditor** | **Effective Date of Report** | **Location of Reserves (Country or Foreign Geographic Area)** | **Audited $MM** | **Evaluated $MM** | **Reviewed $MM** | **Total $MM** |
| Deloitte LLP | December 31, 2019 | Canada | - | 3,817.3 | - | 3,817.3 |
| Deloitte LLP[1] | December 31, 2019 | Canada | - | 75.0 | - | 75.0 |
| McDaniel & Associates Consultants Ltd. | December 31, 2019 | Canada | - | 1,422.1 | - | 1,422.1 |
| **Total**[2] | | | - | **5,314.5** | - | **5,314.5** |

1 Physical marketing contracts, unused fractionation and take-or-pay, and facility and pipeline abandonments
2 Total may not add due to rounding

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

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

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

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 0R8

*Original signed by: "Robin G. Bertram"*
Robin G. Bertram, P. Eng.
Partner

Execution date: February 12, 2020

McDaniel & Associates Consultants Ltd.
2200, 255 – 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

*Original signed by: "Brian Hamm"*
Brian Hamm, P. Eng.
President & CEO

Execution date: February 12, 2020

**FORM 51-101F2**
**REPORT ON CONTINGENT RESOURCES DATA AND PROSPECTIVE RESOURCES DATA**
**BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**

To the Board of Directors of Birchcliff Energy Ltd. (the "**Company**"):

1. We have evaluated the Company's contingent resources data and prospective resources data as at December 31, 2019. The contingent resources data and prospective resources data are risked estimates of volume of contingent resources and prospective resources and related risked net present value of future net revenue as at December 31, 2019, estimated using forecast prices and costs.

2. The contingent resources data and prospective resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the contingent resources data and prospective resources 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 contingent resources data and prospective resources data are free of material misstatement. An evaluation also includes assessing whether the contingent resources data and prospective resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources and prospective resources (before deduction of income taxes) attributed to contingent resources and prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data and prospective resources data that we have evaluated and reported on to the Company's Board of Directors:

| | | | | | **Risked Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)** | | |
|---|---|---|---|---|---|---|---|
| **Classification** | **Independent Qualified Reserves Evaluator or Auditor** | **Effective Date of Evaluation Report** | **Location of Resources Other than Reserves (Country or Foreign Geographic Area)** | **Risked Volume (Bcfe)** | **Audited $MM** | **Evaluated $MM** | **Total $MM** |
| Development Pending Contingent Resources (2C) | Deloitte LLP | December 31, 2019 | Canada | 8,582.9 | - | 1,257.5 | 1,257.5 |

| **Classification** | **Independent Qualified Reserves Evaluator or Auditor** | **Effective Date of Evaluation Report** | **Location of Resources Other than Reserves (Country or Foreign Geographic Area)** | **Risked Volume (Bcfe)** |
|---|---|---|---|---|
| Prospective Resources (Best Estimate) – Prospect | Deloitte LLP | December 31, 2019 | Canada | 5,991.7 |
| Contingent Resources (2C) | Deloitte LLP | December 31, 2019 | Canada | |
| Development On Hold | | | | 2,995.0 |
| Development Unclarified | | | | 118.5 |
| Development Not Viable | | | | 50.2 |

6. In our opinion, the contingent resources data and prospective resources 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 contingent resources data and prospective resources data that we reviewed but did not audit or evaluate.

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

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

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 0R8

*Original signed by: "Andrew R. Botterill"*
Andrew R. Botterill, P. Eng.
Partner

Execution date: March 11, 2020

## APPENDIX C

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

Management of Birchcliff Energy Ltd. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes other information such as contingent resources data and prospective resources data.

Independent qualified reserves evaluators have evaluated the Company's reserves data, contingent resources data and prospective resources data. The reports of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Evaluation Committee of the Board of Directors of the Company has:

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

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

(c) reviewed the reserves data, contingent resources data and prospective resources data with management and the independent qualified reserves evaluators.

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

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

(b) the filing of the Form 51-101F2s which are the reports of the independent qualified reserves evaluators on the reserves data, contingent resources data and prospective resources data; and

(c) the content and filing of this report.

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

(signed) *"A. Jeffery Tonken"*
President and Chief Executive Officer

(signed) *"Christopher A. Carlsen"*
Vice-President, Engineering

(signed) *"James W. Surbey"*
Director and Chairman of the
Reserves Evaluation Committee

(signed) *"Dennis A. Dawson"*
Director and Member of the
Reserves Evaluation Committee

March 11, 2020

**APPENDIX D**

**AUDIT COMMITTEE CHARTER**

**Purpose**

The purpose of the Audit Committee (the "**Committee**") of the board of directors (the "**Board**") of Birchcliff Energy Ltd. (the "**Corporation**") is to assist the Board in overseeing:

(a) the preparation of the financial statements of the Corporation and the conduct of any audit thereof;

(b) the Corporation's compliance with applicable financial reporting requirements; and

(c) the independence and performance of the Auditor.

**Definitions**

For the purposes of this Charter, the following terms have the following meanings:

(a) "**Auditor**" means the auditor appointed to prepare an audit report in respect of the annual financial statements of the Corporation.

(b) "**NI 52-110**" means National Instrument 52-110 – *Audit Committees* promulgated by the securities regulatory authorities in Canada as may be amended from time to time.

**Composition of the Committee**

(a) Number of Members: The Committee shall be composed of a minimum of three members, each of whom shall be a member of the Board.

(b) Independence of Members: Each member of the Committee shall be "independent" within the meaning of NI 52-110 unless the Board determines to rely on an exemption contained in NI 52-110.

(c) Financial Literacy: Each member of the Committee shall be "financially literate" within the meaning of NI 52-110 unless the Board determines to rely on an exemption contained in NI 52-110.

(d) Appointment and Vacancies: The members of the Committee shall be appointed by the Board and shall serve at the pleasure of the Board. Any member of the Committee may be removed or replaced at any time by the Board and shall automatically cease to be a member of the Committee as soon as such member ceases to be a director of the Corporation. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all of its powers so long as a quorum remains.

(e) Chair: The Board shall designate one member of the Committee as the chairperson of the Committee (the "**Chair**"). The Chair shall preside over all meetings of the Committee, and in the Chair's absence, the members of the Committee may designate from among such members the Chair for the purpose of such meeting.

**Transaction of Business and Meetings**

(a) Transaction of Business: The Committee shall transact its business in accordance with governing corporate legislation and the provisions of the by-laws of the Corporation. To the extent not provided either therein or in the provisions of this Charter, the Committee may determine the manner in which it will transact its business by way of resolution passed by a majority of votes cast thereon.

(b) Number of Meetings: The Committee shall meet at least four times per year or more frequently as is necessary to carry out its duties and responsibilities.

(c) Calling of Meetings: The Chair or any member of the Committee may at any time convene a meeting of the Committee. Upon a request from the Auditor, the Chair shall convene a meeting of the Committee to consider any matters that the Auditor desires to bring to the attention of the Committee.

(d) Notice of Meetings: Notice of meetings shall be delivered, mailed, faxed, emailed or sent by any other form of transmitted or recorded message to each member of the Committee not less than forty-eight hours before the meeting is to take place. Notice of any meeting or any irregularity thereof may be waived by any member. Meetings may be held at any time without formal notice if all the members are present, or if a quorum is present and those members who are absent have signified their consent to the meeting being held in their absence. Any resolution passed or action taken at such a meeting shall be valid and effectual as if it had been passed or taken at a meeting duly called and constituted.

(e) Quorum: A quorum for meetings of the Committee shall be at least two members of the Committee. No business may be transacted by the Committee at a meeting unless a quorum of the Committee is present.

(f) Voting: All motions made at a meeting of the Committee shall be decided by a simple majority of votes cast by members of the Committee who vote on such motion. In the event of an equality of votes on any motion, the Chair shall not have a second or casting vote.

(g) Minutes and Reporting to the Board: Minutes shall be prepared of all meetings of the Committee. A copy of such minutes shall be circulated to all members of the Committee and the Board. In addition, the Chair may report orally to the Board on any matter in his or her view requiring the immediate attention of the Board.

(h) Attendance of Non-Members: The Committee may invite to a meeting any officers, directors or employees of the Corporation, legal counsel, advisors and other persons whose attendance it considers necessary or desirable in order to carry out its duties and responsibilities. If not a member of the Committee, such invitees shall have no voting rights at any meeting of the Committee.

**Duties and Responsibilities**

***External Auditor***

(a) The Committee shall recommend to the Board:

  (i) the person or firm to be nominated as Auditor for the purposes of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation; and

  (ii) the compensation of the Auditor.

(b) The Committee is authorized in carrying out its duties to communicate directly with the Auditor and the Auditor shall report directly to the Committee. The Committee shall be directly responsible for overseeing the work of the Auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the Auditor regarding financial reporting.

(c) The Committee shall review and recommend to the Board the annual audit plan of the Auditor and the terms of the Auditor's engagement, including the appropriateness and reasonableness of the Auditor's fees.

(d) The Committee may review and evaluate the Auditor's performance.

(e) The Committee shall review and receive assurances as to the independence of the Auditor.

(f) The Committee shall review any reports issued by the Canadian Public Accountability Board which specifically relate to any previous audit of the financial statements of the Corporation.

(g) The Committee shall periodically meet with the Auditor without management present to discuss the completeness and accuracy of the Corporation's financial statements.

(h) When there is to be a change in the Auditor, the Committee shall review the issues related to the change and shall approve the information to be included in the notice of such change required to be filed with the applicable regulatory authorities.

(i) The Committee shall pre-approve all non-audit services to be provided to the Corporation (or its subsidiary entities, if any) by the Auditor. The Committee may delegate this function to one of its independent members, who shall report to the Committee on any such approvals.

***Financial Reporting and Public Disclosure***

(j) The Committee shall review, report to the Board on and, if deemed advisable by the Committee, recommend to the Board for approval, the Corporation's interim and annual financial statements and all related management's discussion and analysis before those materials are filed with the applicable regulatory authorities and publicly disclosed. If authorized by the Board, the Committee may approve the interim financial statements and the related management's discussion and analysis, before those materials are filed with the applicable regulatory authorities and publicly disclosed. The Committee shall receive and review any reports prepared by management of the Corporation or the Auditor that relate to any of the following:

    (i) changes in accounting principles, or in their application, which may have a material impact on a current or future year's financial statements;

    (ii) significant accruals, reserves or other estimates, such as ceiling test calculations;

    (iii) the accounting treatment of significant, unusual or non-recurring transactions;

    (iv) disclosures of commitments and contingencies;

    (v) adjustments raised by the Auditor, whether or not included in the financial statements;

    (vi) unresolved differences between management and the Auditor;

    (vii) explanations of significant variances with comparative reporting periods; and

    (viii) related party transactions and ensuring that the nature and extent of such transactions are properly disclosed.

(k) The Committee shall review, report to the Board on and, if deemed advisable by the Committee, recommend for approval by the Board, the Corporation's annual and interim earnings press releases before the Corporation publicly discloses this information.

(l) As it relates to financial information that is extracted or derived from the Corporation's financial statements, the Committee shall review, report to the Board on and, if deemed advisable by the Committee, recommend for approval by the Board, all annual reports, annual information forms, information circulars, business acquisition reports, prospectuses and other securities offering documents (excluding, for greater certainty, the Corporation's corporate presentations) before such documents are publicly disclosed and, if applicable, filed with the applicable regulatory authorities.

(m) The Committee shall ensure that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements and shall periodically assess the adequacy of those procedures.

***Internal Controls***

(n) The Committee shall oversee management's reporting on internal controls and shall advise the Board of any material failures of the internal controls.

(o) The Committee shall establish procedures:

    (i) for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters; and

    (ii) for the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

***Other Duties and Responsibilities***

(p) The Committee shall review management's reports regarding the certification of annual and interim financial reports in accordance with applicable securities legislation.

(q) The Committee shall review and approve:

    (i) the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former Auditor; and

    (ii) the employment by the Corporation of any current or former partner or employee of the present and former Auditor.

(r) The Committee shall review, at least annually, this Charter and recommend to the Board any amendments to this Charter that the Committee considers necessary or advisable.

(s) The Committee shall bring to the attention of the Board such other issues as are necessary to carry out its mandate and shall make recommendations to the Board with respect to the foregoing. In addition, the Committee shall review and report to the Board on any other matters as may be delegated to it by the Board from time to time.

**Access to Information and Advisors**

(a) In discharging its role, the Committee shall have full access to all books, records, facilities and personnel of the Corporation to the extent that the same relate to matters that are the responsibility of the Committee under this Charter. The Committee may require the Auditor or any director, officer or employee of the Corporation to appear before it to discuss the accounts and records and/or financial position of the Corporation. Members of the Committee may rely upon the accuracy of any statement or report prepared by the Auditor or upon any other statement or report including any appraisal report prepared by a qualified person and shall not be responsible or held liable for any loss or damage in respect of any action taken on the basis of such statement or report.

(b) The Committee has the authority to engage such advisors (including independent legal counsel) as it considers necessary or desirable to assist it in fulfilling its duties and responsibilities as provided in this Charter and to set the compensation to be paid thereto, such engagement to be at the Corporation's expense. The Corporation shall be responsible for all other expenses of the Committee that are deemed necessary or desirable by the Committee in order to fulfil its duties and responsibilities as provided for in this Charter.

Approved and Adopted: March 14, 2018.