HEADWATER EXPLORATION INC.

ANNUAL INFORMATION FORM

Year Ended December 31, 2020

Dated March 10, 2021

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ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
MBbls	thousand barrels
MMBbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
MM	Million

Other

AECO	A natural gas storage facility located at Suffield, Alberta
AGT	Algonquin City-Gate natural gas pricing point on the Algonquin gas pipeline system
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas
BOE/d	barrel of oil equivalent per day
m3	cubic metres
MBOE	1,000 barrels of oil equivalent
MMBOE	1,000,000 barrels of oil equivalent
Mcfe	thousand of cubic feet equivalent
NYMEX	New York Mercantile Exchange
$000s	thousands of dollars
$M	thousands of dollars
$MM	millions of dollars
WCS	Western Canadian Select, a heavy sour Canadian crude oil blended at Port Hardisty, Alberta with a nominal API gravity of 20.5 degrees.
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of BOEs of Mcfes may be misleading, particularly if used in isolation. A BOE and Mcfe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given 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 ratio at 6:1 may be misleading as an indication of value.

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls oil	6.290
feet	meters	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres (Alberta)	hectares	0.400
hectares (Alberta)	acres	2.500

NOTES ON RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil, NGLs and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of Headwater's anticipated oil, NGLs and natural gas reserves does not represent the fair market value of Headwater's proposed reserves.

Oil and Gas Definitions

Certain terms used in this Annual Information Form in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this Annual Information Form, but not defined or described, are defined in National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") or the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**API gravity**" means the American Petroleum Institute gravity expressed in degrees in relation to liquids, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

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

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems;

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

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploration wells and exploration type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploration wells; and (e) costs of drilling exploration type stratigraphic test wells;

"**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well;

"**forecast prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Headwater 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 subparagraph (a);

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

"**net**" means: (a) in relation to an issuer's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves; (b) in relation to an issuer's interest in wells, the number of wells obtained by aggregating the issuer's working interest in each of its gross wells; and (c) in relation to an issuer's interest in a property, the total area in which the issuer has an interest multiplied by the working interest owned by the issuer;

"**P+P Reserves**" means Proved Reserves plus Probable Reserves;

"**Probable Reserves**" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated P+P Reserves;

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

"**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: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates;

"**Reserves Data**" has the meaning set forth under the heading "*Statement of Reserves Data and other Oil and Gas Information*" in this Annual Information Form;

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status; and

"**working interest**" means the percentage of undivided interest held by an issuer in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the issuer the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Levels of Certainty for Reported Reserves

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

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

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated P+P Reserves.

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

NON-IFRS MEASURES

In the Annual Information Form, the Corporation uses the terms "free cash flow" and "adjusted working capital". These measures are not recognized by International Financial Reporting Standards ("**IFRS**") and do not have standardized meanings prescribed by IFRS. Therefore, they may not be comparable to performance measures presented by others. Free cash flow is calculated as cash flow from operations, adjusted for non-cash working capital less capital expenditures. Headwater uses free cash flow as an indicator of liquidity to measure funds available after capital investment. Adjusted working capital is calculated as working capital excluding the effects of the Corporation's financial derivative commodity contracts and the warrant liability. Adjusted working capital is used by the Corporation to measure liquidity.

CERTAIN DEFINITIONS

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

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended, including any regulations promulgated thereunder;

"**Acquired Assets**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

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

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

"**Cenovus**" means Cenovus Energy Inc.;

"**Cenovus Transaction**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**Cenovus Warrants**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**CMHP**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

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

"**Corporation**" or "**Headwater**" means Headwater Exploration Inc., a corporation existing under the ABCA;

"**Development Agreement**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**GLJ**" means GLJ Ltd.;

"**GLJ Report**" means the independent reserves assessment prepared by GLJ dated February 22, 2021 evaluating the oil and gas properties of the Corporation as at December 31, 2020;

"**Initial Investors**" means, collectively, Neil Roszell, Jason Jaskela, Ali Horvath, Jonathan Grimwood and Terry Danku;

"**Investment Agreement**" means the amended and restated investment agreement entered into by the Corporation and the Initial Investors on January 15, 2020;

"**Investor Agreement**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

"**M&NP**" means the Maritimes & Northeast Pipeline;

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

"**OPEC+**" means the Organization of the Petroleum Exporting Countries and certain additional plus countries;

"**Private Placements**" means together, the Subscription Receipt Private Placement and the Unit Private Placement;

"**Reconstitution of Management**" means, concurrently with the Unit Private Placement: (i) the resignation and appointment of directors in accordance with the Investment Agreement, such that following the reconstitution, the members of the Board were as follows: Chandra Henry, Martin Fräss-Ehrfeld, Jason Jaskela, Phillip Knoll, Stephen Larke, Kevin D. Olson, David Pearce and Neil Roszell; and (ii) the resignation and appointment of officers of the Corporation in accordance with the Investment Agreement, such that following the reconstitution, the officers of the Corporation were Neil Roszell as Chairman and Chief Executive Officer, Jason Jaskela as President and Chief Operating Officer, Ali Horvath as Vice President, Finance and Chief Financial Officer, Jonathan Grimwood as Vice President, Exploration, Terry Danku as Vice President, Engineering, Scott Rideout as Vice President, Land and Edward (Ted) Brown as Corporate Secretary;

"**Repsol**" means Repsol Oil & Gas Canada Inc.;

"**Royalty Agreement**" has the meaning ascribed thereto under the heading "*General Development of the Business – Year 2020 – Transaction with Cenovus*";

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

"**Subscription Receipt Agreement**" means the subscription receipt agreement dated February 11, 2020 between the Corporation, Stifel Nicolaus Canada Inc., National Bank Financial Inc. (on their own behalf and on behalf of Peters & Co. Limited) and Computershare Trust Company of Canada;

"**Subscription Receipt Private Placement**" means the brokered private placement of 32,608,696 Subscription Receipts at a price of $0.92 per Subscription Receipt for gross aggregate proceeds of approximately $30 million completed on February 11, 2020 as part of the Private Placements and Reconstitution of Management;

"**Subscription Receipts**" means the subscription receipts of the Corporation issued pursuant to the Subscription Receipt Private Placement, with each subscription receipt entitling the holder thereof to receive, without payment of additional consideration or further action on the part of such holder, one (1) Common Share upon the satisfaction of certain conditions, including that all conditions, undertakings and other matters to be satisfied, completed or otherwise met prior to the completion of the Unit Private Placement and Reconstitution of Management (in accordance with the Investment Agreement) without waiver or material amendment thereof, have been satisfied, completed or otherwise met;

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

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

"**Unit**" means a unit of the Corporation comprised of one (1) Common Share and one (1) Warrant;

"**Unit Private Placement**" means the private placement of 21,739,130 Units of the Corporation at a price of $0.92 per Unit for gross aggregate proceeds of approximately $20.0 million completed on March 4, 2020 as part of the Private Placements and Management Reconstitution; and

"**Warrants**" means the common share purchase warrants issued under the Unit Private Placement, each Warrant entitling the holder to purchase one Common Share at a price of $0.92 per Common Share for a period of four (4) years from the issuance date and which vest and become exercisable as to one-third upon the 20 day volume weighted average price of the Common Shares equaling or exceeding each of $1.30, $1.60 and $1.90 per Common Share, respectively, for Warrants issued under the Unit Private Placement;

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2020.

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

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

The information herein contains forward-looking statements or forward-looking information (collectively, "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict, "potential", "targeting", "intend", "could", "might, "should", "believe", "would" and similar expressions. Such statements and assumptions also include those relating to: the potential for the Corporation to pursue further development of the McCully Field assets to supply natural gas to the undersupplied market in Atlantic Canada; Headwater's intent to provide attractive long-term shareholder returns by focusing on asset quality and sustainability while maintaining a pristine balance sheet; the intent to actively pursue strategic acquisitions with synergistic characteristics such as existing long life producing assets or opportunities with significant, low risk upside potential; Headwater's plans to continue Cenovus' efforts to de-risk the approximate 250 sections of exploration acreage in Marten Hills using a methodical delineation approach; the expectation that the environmental footprint associated with the development of the Marten Hills assets will be minimized with pipeline connected multi-well pad development; the expectation that fresh water usage in Marten Hills will be negligible; the expectation that no fracture stimulations will be required to realize the full potential of the Marten Hills assets; the expectation that future enhanced oil recovery initiatives in Marten Hills will be implemented using only saline water; Headwater's intent to maintain an Liability Management Rating above the industry average; Headwater's plan to strategically develop its Marten Hills assets through implementation of enhanced oil recovery techniques including waterfloods and potentially polymer floods; the intent to focus on operational and cost efficiencies to increase returns; Headwater's intent to identify ways to maximize the return on the invested capital through operational and cost efficiencies; Headwater's plans to utilize its free cash flow and working capital surplus to provide financial flexibility for future development and acquisitions; Headwater's expectations of maintaining its strong balance sheet with significant liquidity to enable future internal development opportunities and potential acquisitions; the intent to continue to optimize production timing from the McCully Field to periods when natural gas prices are higher; details of the Corporation's 2021 capital expenditure program including the number and types of wells to be drilled and other capital expenditures to be undertaken; development plans for the assets of the Corporation; land expiries; expected abandonment and reclamation costs; the performance characteristics of oil and natural gas properties; the quantity of reserves; future crude oil, NGLs and natural gas production levels; drilling plans; anticipated future crude oil, natural gas and NGLs prices and currency, exchange and interest rates; the tax horizon of Headwater; supply and demand for oil and natural gas; expectations regarding Headwater's ability to raise capital and to continually add to reserves through acquisitions and development; the timing and the amounts of expenditures to be made by the Corporation under the Development Agreement; and treatment under government regulatory and taxation regimes. Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Headwater believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because Headwater can give no assurance that such expectations will prove to be correct.

In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: that the Corporation will be able to capitalize on potential asset consolidations and/or other acquisition opportunities in the current economic environment; that royalty regimes will not be subject to material modification; that the Corporation will be able to obtain skilled labour and other industry services at reasonable rates; that the timing and amount of capital expenditures and implementation thereof will be consistent with the Corporation's expectations; that the conditions in general economic and financial markets will not continue to vary materially; that drilling and other equipment will be available on acceptable terms; that government regulations and laws will not change materially; that future operating costs will be consistent with the Corporation's expectations; the impact of increasing competition; the general stability of the economic and political environment in which

Headwater operates; the timely receipt of any required regulatory approvals; the ability of Headwater to obtain qualified staff, equipment and services in a timely manner; future drilling results; the ability of Headwater to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Headwater to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Headwater operates; and the ability of Headwater to successfully market its oil and natural gas products.

A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with public health risks including the 2019 novel coronavirus ("**COVID-19**"), risks associated with volatility of commodity prices and stock exchanges, oil and natural gas exploration, development, exploitation, production, changes to the Corporation's capital budget, marketing and transportation, loss of markets, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, ability to access sufficient capital from internal and external sources and the risk factors outlined under "*Risk Factors*" and elsewhere herein. Operations may be unsuccessful or delayed as a result of the province-wide fracking moratorium in New Brunswick, competition for services, supplies and equipment, mechanical and technical difficulties, challenges associated with attracting and retaining employees on a cost-effective basis, and commodity and marketing risks. The Corporation is subject to significant drilling risks and uncertainties relating to its ability to find oil and natural gas reserves on an economic basis and the potential for technical problems that could lead to well blowouts and environmental damage. The Corporation is also exposed to risks relating to obtaining timely regulatory approvals, surface access, transportation and other third party related operational risks. Furthermore, there are numerous uncertainties in estimating the Corporation's reserve base due to the complexities in estimated future production, costs and timing of expenses and future capital. The Corporation is subject to regulatory legislation, which may require significant expenditures to ensure compliance or which may result in fines, penalties or production restrictions for non-compliance.

The forward-looking statements contained herein are as of March 10, 2021 and are subject to change after this date. 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 and, as such, undue reliance should not be placed on forward-looking statements. Except as required by law, Headwater disclaims any intention or obligation to update or revise these forward-looking statements, whether as a result of new information, future events or otherwise.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. For a full description of the risk factors, please see "Risk Factors" in this Annual Information Form.

THE CORPORATION

General

Headwater is the corporation resulting from the amalgamation under the ABCA on May 13, 1996 of "Corridor Resources Inc." and Contwoyto Goldfields Limited. On June 14, 2011, the articles of the Corporation were amended to increase the minimum and maximum number of directors of the Corporation to three directors and nine directors, respectively. On March 4, 2020, in connection with the Private Placements and the Reconstitution of Management, the Corporation filed Articles of Amendment to change its name from "Corridor Resources Inc." to "Headwater Exploration Inc." The Corporation has no material subsidiaries.

The head office of Headwater is located at 1200, 500 – 4th Avenue S.W., Calgary, Alberta T2P 2V6 and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

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

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary description of the development of Headwater's business during the last three completed financial years.

Year 2020

Transaction with Cenovus

On November 8, 2020, the Corporation entered into a purchase and sale agreement with Cenovus and an affiliate of Cenovus, Cenovus Marten Hills Partnership ("**CMHP**"), to acquire 100% of Cenovus' assets in the Marten Hills area of Alberta (the "**Acquired Assets**") from CMHP. Pursuant to the agreement, Headwater acquired a 100% working interest in approximately 2,800 barrels per day of heavy oil production and 270 net sections of Clearwater rights (the "**Cenovus Transaction**"). The Cenovus Transaction closed on December 2, 2020. Consideration paid by Headwater for the Acquired Assets consisted of (i) the issuance to CMHP of 50.0 million Common Shares of the Corporation and 15.0 million Common Share purchase warrants (the "**Cenovus Warrants**") of the Corporation; and (ii) a cash payment of $32.8 million to CMHP for total consideration of approximately $135.3 million (prior to customary closing adjustments). Each Cenovus Warrant entitled CMHP to acquire one Common Share at a price of $2.00 per Common Share for a period of three (3) years. Headwater has the right, after twelve months have elapsed from December 2, 2020 and provided the 20-day volume weighted average trading price of the Common Shares exceeds $2.00, to require Cenovus to exercise all or a portion of the then-outstanding Cenovus Warrants.

At closing of the Cenovus Transaction, CMHP and Headwater entered into the investor agreement (the "**Investor Agreement**") as described further under the heading "*Material Contracts*".

Headwater and CMHP also entered into a development agreement (the "**Development Agreement**") and a royalty agreement (the "**Royalty Agreement**") in connection with the Cenovus Transaction. Pursuant to the Development Agreement, Headwater committed to spend $100.00 million in capital expenditures on the Acquired Assets by December 31, 2022, unless otherwise extended by CMHP. Pursuant to the Royalty Agreement, Cenovus retained a gross overriding royalty on the lands comprising the Acquired Assets.

In connection with the Cenovus Transaction and in accordance with the terms of the Investor Agreement, Kam Sandhar and Sarah Walters were appointed to the Board.

Private Placements and Reconstitution of Management

On January 12, 2020, the Corporation entered into an initial investment agreement (the "**Initial Investment Agreement**") with the Initial Investors which provided for: (i) the Unit Private Placement; (ii) a brokered private placement of Common Shares for gross proceeds of a minimum of $20.0 million and a maximum of $30.0 million (the "**Brokered Share Private Placement**"); and (iii) the Reconstitution of Management. On January 15, 2020, in light of the TSX requiring the Corporation obtain approval of an ordinary resolution in respect of the Unit Private Placement at a special meeting ("**Special Meeting**") of the Shareholders (the "**Unit Private Placement Resolution**"), the Corporation and the Initial Investors entered into the Investment Agreement to substitute the Subscription Receipt Private Placement for the Brokered Share Private Placement. On February 11, 2020, the Corporation completed the Subscription Receipt Private Placement.

On March 4, 2020, the Corporation held the Special Meeting and the Unit Private Placement Resolution as well as a special resolution to amend the articles of the Corporation to change its name from "Corridor Resources Inc." to "Headwater Exploration Inc." were approved.

Following the Special Meeting, the Unit Private Placement and Reconstitution of Management were completed and the Common Shares underlying the Subscription Receipts were issued in accordance with the terms of the Subscription Receipt Agreement. In addition, the Corporation filed Articles of Amendment to change its name to "Headwater Exploration Inc.".

For a complete description of the transactions contemplated by the Investment Agreement, reference should be made to the Investment Agreement and the material change report of the Corporation dated March 13, 2020, copies of which have been filed on SEDAR at www.sedar.com.

McCully Operations

As part of its production optimization strategy, the Corporation shut-in its natural gas production in the McCully Field in New Brunswick in May 2020 and resumed production in late October 2020. Headwater's natural gas production from the McCully Field averaged 3.8 MMcf/d in 2020. No development operations occurred as the lifting of the fracking moratorium in the Sussex region remained uncertain.

Year 2019

On October 31, 2019, the Corporation announced that the Board had approved the initiation of a strategic review process to explore and develop strategic alternatives with a view of enhancing Shareholder value. The process was intended to explore a comprehensive range of strategic transaction alternatives including: (i) opportunities to selectively deploy capital (within the resource sector or otherwise); (ii) a disposition of all or substantially all of the Corporation's assets; and (iii) a merger or other business combination. In connection with the strategic review process, the Corporation engaged RBC Dominion Securities Inc. as financial advisor to assist in undertaking the process.

As part of its production optimization strategy, the Corporation shut-in its natural gas production in the McCully Field in New Brunswick in May 2019 and resumed production in November 2019.

Year 2018

In November 2018, the Government of New Brunswick expressed its intention to allow natural gas development in the Sussex region, where the Corporation's properties are located. On December 19, 2018, the Corporation announced that its future activities in respect of the Frederick Brook shale would be focused on initially attracting a joint venture partner to bring capital and shale gas expertise to assist with further evaluation of the Frederick Brook shale by way of a pilot project to be developed with such joint venture partner.

As part of its production optimization strategy, the Corporation shut-in its natural gas production in the McCully Field in New Brunswick in May 2018 and resumed limited production in November 2018, with a ramp-up in production in December 2018. The Corporation sells all of its share of the natural gas produced from the McCully Field to Repsol pursuant to a long-term agreement. In 2018, the Corporation and Repsol amended their long-term agreement to eliminate transportation charges on the Canadian portion of the M&NP from November 1, 2018 to April 1, 2024 in recognition of the changing market.

In June 2018, the Corporation concluded there was no longer a viable path to drilling an exploration well on the Old Harry prospect in the Gulf of St. Lawrence before the current exploration licence on the Newfoundland side expires in January 2021 and, accordingly, the Corporation determined to suspend any further technical work and capital spending on the Old Harry prospect.

The Corporation implemented a normal course issuer bid (the "**NCIB**") under the TSX that commenced on August 23, 2018 that expired on August 22, 2019. Under the NCIB, the Corporation purchased 777,460 Common Shares.

Significant Acquisitions

On December 2, 2020, Headwater completed the Cenovus Transaction, for total consideration of approximately $135.3 million (prior to customary closing adjustments) comprised of: (i) 50.0 million Common Shares and 15.0 million Cenovus Warrants of the Corporation; and (ii) a $32.8 million cash payment to CMHP. See "*General Development of the Business – Year 2020 – Transaction with Cenovus"*.

Headwater filed a Form 51-102F4 – *Business Acquisition Report* dated February 10, 2021, in respect of the Cenovus Transaction.

DESCRIPTION OF THE BUSINESS

The Corporation is a Canadian junior resource company currently engaged in the exploration for, development of, and production of petroleum and natural gas in the Western Canadian Sedimentary Basin and onshore in New Brunswick. With the completion of the Cenovus Transaction, Headwater acquired high quality oil production, reserves and lands in the Clearwater play in the Marten Hills area of Alberta. In addition, the Corporation currently has low decline natural gas production and reserves in the McCully Field near Sussex, New Brunswick and a shale gas prospect in New Brunswick.

The Headwater management team is focused on exploration and development in the Marten Hills area as well as potentially expanding its operations to include resource exploration and development in other areas of the Western Canadian Sedimentary Basin. The historic assets of the Corporation in New Brunswick provide production and cash flow for the Corporation's operations. To the extent that the New Brunswick government's fracking moratorium is lifted in respect of the Corporation's assets in the McCully Field, the Corporation may pursue further development of such assets to supply natural gas to the undersupplied market in Atlantic Canada.

Business Strategy

Headwater's business strategy is to provide attractive long-term shareholder returns by focusing on asset quality and sustainability while maintaining a pristine balance sheet.

Headwater seeks to execute this strategy by:

- ***Focusing on asset quality.*** Headwater strives to actively pursue strategic acquisitions with synergistic characteristics such as existing long life producing assets or opportunities with significant, low risk upside potential.

- ***Exploring undeveloped lands through drilling.*** Headwater plans to continue Cenovus' efforts to de-risk the approximate 250 sections of exploration acreage. The 6 historical exploration wells drilled by Cenovus have established multiple potential development areas, which Headwater intends to follow-up on using a methodical delineation approach.

- ***Prioritizing ESG***. Headwater strives to be an industry environmental, social and governance leader. The environmental footprint associated with the development of the newly acquired Marten Hills assets will be minimized with pipeline connected multi-well pad development. Fresh water usage will also be negligible with no fracture stimulations required to realize the full potential of the assets and future enhanced oil recovery initiatives currently planned to be implemented using only saline water. As at December 31, 2020, Headwater's Liability Management Rating ("LMR") was 31 in Alberta significantly exceeding the Alberta industry LMR average. Headwater remains committed to maintaining an LMR rating above the industry average. Finally, Headwater has enacted various governing principles that ensure strong alignment with our various stakeholders and the environment.

- ***Sustainability***. Headwater plans to strategically develop its Marten Hills assets through implementation of enhanced oil recovery techniques including waterfloods and potentially polymer floods.

- ***Focusing on operational and cost efficiencies to increase returns***. Headwater reviews operating measures, evaluates drilling results and monitors the results and use of technology by other industry players to identify ways to maximize the return on the invested capital through operational and cost efficiencies.

- ***Maintaining financial discipline.*** Headwater plans to utilize its free cash flow and working capital surplus to provide financial flexibility for future development and acquisitions. Headwater expects to maintain its strong balance sheet with significant liquidity to enable future internal development opportunities and potential acquisitions. As at December 31, 2020, Headwater had adjusted working capital of $80.8 million and no debt.

See "*Industry Conditions*" and "*Risk Factors*" for further details.

Specialized Skill and Knowledge

The Corporation relies on specialized skills and knowledge to gather, interpret and process geophysical data; drill and complete wells; design and operate production facilities; evaluate and complete acquisitions of assets; and for numerous additional activities required to explore for and produce oil and natural gas. The Corporation has employed a strategy of contracting consultants and other services providers to supplement the skills and knowledge of its permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operation effectively. See "*Directors and Executive Officers of the Corporation*".

Reorganizations

There have been no material reorganizations of the Corporation in the last three completed financial years or proposed for the current financial year.

Personnel

As of December 31, 2020, the Corporation had 13 employees and 5 consultants in the Calgary head office, 1 employee in Halifax, 4 employees in the field in New Brunswick and 3 consultants in the field in Marten Hills.

As of March 10, 2021, the Corporation had 17 employees and 5 consultants in the Calgary head office, 1 employee in Halifax, 4 employees in the field in New Brunswick and 3 consultants in the field in Marten Hills. The Corporation has sufficient personnel to execute on its business strategy.

Marketing

Headwater's heavy crude production in the Marten Hills area is sold through various counterparties at current market prices. In connection with the Cenovus Transaction, Headwater and Cenovus entered into a marketing agreement. Headwater considers the marketing agreement to be at market terms and in the ordinary course of business. The marketing agreement terminates on December 2, 2023. The Corporation has various take or pay pipeline service agreements to deliver its production from the Marten Hills area to market that expire in 2031. For details of the Corporation's transportation agreements in place as at December 31, 2020, see the Corporation's audited annual financial statements for the year ended December 31, 2020, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com.

A key component of the Corporation's production optimization strategy related to its McCully assets is to enter into financial hedges to mitigate the risks associated with the volatility of natural gas prices during the winter heating season when natural gas is produced from the McCully Field.

The Corporation produces natural gas from the McCully Field in New Brunswick, which is connected to the M&NP that supplies customers in the Maritimes and the New England market in the northeastern U.S. The New England market has in recent years been characterized by excess demand during the winter season resulting in elevated prices for natural gas as compared to prices in other areas of North America, and this excess demand is expected to continue until new pipeline infrastructure is available to increase the supply of natural gas into this market. In January 2021, the Weymouth compressor was fully placed in service facilitating increased delivery of natural gas to Atlantic Canada. Additional projects are planned which could alleviate supply constraints in the New England and Maritimes markets, although it is not known whether the required regulatory approvals will be received and, if the projects proceed, the timing of completion of such projects. In addition, natural gas production from Sable Island and Deep Panuke in the Maritimes ended in 2018 resulting in excess demand and expected higher natural gas prices in the Maritimes.

The Corporation sells all of its share of the natural gas produced from the McCully Field to Repsol pursuant to a long-term agreement which became effective on April 1, 2009 and will terminate on April 1, 2024. The Corporation's natural gas production has historically been sold in the New England market in the northeastern U.S. at prices referenced to AGT but has recently been expanded to include sales to local markets in the Maritimes given the decrease in natural gas production in Atlantic Canada. In 2018, the Corporation and Repsol amended their long-term agreement to eliminate transportation charges on the Canadian portion of the M&NP from November 1, 2018 to April 1, 2024 in recognition of the changing market.

The production, transportation, processing and marketing of natural gas from Nutrien Ltd.'s ("**Nutrien**") share of the production from the McCully Field are subject to agreements with Nutrien. Nutrien's share of natural gas production is either taken in kind for use at the Nutrien potash facility, located near Sussex, New Brunswick or delivered to the Corporation's midstream facilities for sale by Nutrien to the Maritimes market and New England market.

The Corporation has also adopted a hedging policy – see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Forward Contracts*". For details of the Corporation's forward contracts in place as at December 31, 2020 and subsequent to December 31, 2020, see the Corporation's audited annual financial statements for the year ended December 31, 2020, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Prices, Markets and Marketing*".

Cyclical and Seasonal Nature of Industry

Headwater's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely recently and are determined by supply and demand factors. The energy business is cyclical in nature and heavily influenced on macro-economic cycles and other factors affecting supply and demand. In periods of economic expansion and growth the demand for energy increases as economies build inventory and productive capacity. Generally speaking in periods of economic contraction or recession, demand for energy declines. These macroeconomic cycles often impact global, North American and local prices for commodities, particularly oil and gas prices. In addition, the actions of OPEC and other oil producing countries and other factors impacting supply of oil will impact the price of oil. Weather and general economic conditions, as well as conditions in other oil and natural gas regions, also impact supply and demand of commodity prices and costs. Any decline in oil and natural gas prices could have an adverse effect on Headwater's financial condition. Headwater mitigates such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to lock-in high netbacks on production volumes.

The Corporation produces natural gas from the McCully Field in New Brunswick, which is connected to the M&NP that supplies customers in the Maritimes and the New England market in the northeastern U.S. The New England market has in recent years been characterized by excess demand during the winter season resulting in elevated prices for natural gas as compared to prices in other areas of North America, and this excess demand is expected to continue until new pipeline infrastructure is available to increase the supply of natural gas into this market. As a result, the Corporation shut-in its production from the McCully Field in the summer months and only produces in the winter months when the prices are higher.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In anticipation of the operational delays associated with "spring break up", the Corporation takes certain steps to mitigate interruption to its activities including, scheduling drilling and completion activities to be completed well before the spring break up season and setting up extra storage where possible to mitigate downtime. Through the duration of spring break up, drilling and exploratory activities slow and the Corporation's production which is not otherwise tied-in may be shut in temporarily if access is limited.

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

See "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*", "*Risk Factors – Seasonality*" and "*Risk Factors – Acute Climate Change Risk*".

Environmental Considerations and Protection

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

Headwater believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs. As at December 31, 2020, Headwater's LMR was 31 in Alberta significantly exceeding the Alberta industry LMR average.

The federal government and certain provincial governments have enacted legislation aimed at discouraging the use of fossil fuels in an effort to decrease greenhouse gas emissions. Over the long-term laws designed to curb the use of fossil fuels in Canada and other countries could have an impact on the demand for fossil fuels and have a negative impact on the price of oil and natural gas, which would have an effect on the Corporation's financial results and ultimately the sustainability of the Corporation's business model. Headwater does not have any facilities that exceed current emissions thresholds that would subject Headwater to more onerous requirements, the short-term impact of carbon taxes and similar measures are not expected to have a material effect on the Corporation's financial results. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*" and "*Risk Factors – Carbon Pricing Risk*".

Although Headwater operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety, occasionally fluid spills and other incidents threatening the environment may occur. The costs of cleaning up such spills could negatively affect the Corporation's financial and operating results as the Corporation has to incur costs and utilize resources in cleaning up such spills. In 2020, the Corporation did not have any material spills or releases.

Health, Safety, Environmental and Social Policies

In addition to the Board's oversight of Headwater's environmental and safety practices, management, employees and all contractors will be responsible and accountable for the overall health, safety and environmental program. Headwater operates in compliance with all applicable regulations and ensures that all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

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

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

The Corporation also has an Emergency Response Plan (the "**ERP**") which is prepared in accordance with applicable regulations. The ERP is designed to provide the policies, practices and procedures to be implemented in the event of an emergency situation that arises at or as a result of Headwater's operations, including but not limited to: a serious injury or fatality, fire or explosion, uncontrolled or hazardous product release and oil or hazardous chemical spill. The purpose of the ERP is to protect the health, safety and welfare of the public and workers and minimize the potential adverse environmental effects. Management intends to test the ERP in 2021 to ensure its effectiveness and its procedures are revised to ensure the Corporation is adhering to the highest industry standards.

The Board also receives periodic updates from management on implemented or proposed legislative or regulatory changes that may affect the Corporation's operations. Periodically, the Board discusses and reviews Headwater's environmental, health and safety policies and, with management input, makes suggestions to ensure that the Corporation is adhering to best practices within the industry.

Competitive Conditions

Headwater is a member of the petroleum industry, which is highly competitive at all levels. Headwater competes with other companies for all of its business inputs, including exploitation and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors – Competition*".

Headwater strives to be competitive by maintaining a strong financial condition and by utilizing current technologies to enhance exploitation, development and operational activities.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Reserves Data**") is dated March 10, 2021. The effective date of the Reserves Data is December 31, 2020 and the preparation date of the Reserves Data is February 22, 2021.

Disclosure of Reserves Data

The Reserves Data set forth below is based upon the evaluation by GLJ with an effective date of December 31, 2020 contained in the GLJ Report. The Reserves Data summarizes the NGLs, natural gas, shale gas and heavy crude oil reserves associated with the Corporation's assets and the net present values of future net revenue for such reserves using forecast prices and costs. The tables below are a combined summary of the Corporation's NGLs, natural gas, shale gas and heavy crude oil reserves and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Report based on forecast price and cost assumptions. The NGLs, natural gas, shale gas and heavy crude oil reserve estimates presented in the GLJ Report are based on the guidelines contained in the COGE Handbook and the reserve definitions contained in both NI 51-101 and the COGE Handbook. A summary of those definitions are set forth under the heading "Notes on Reserves Data and Other Oil and Gas Information" in this Annual Information Form. GLJ was engaged to provide evaluations of Proved Reserves and P+P Reserves and no attempt was made to evaluate possible reserves. Additional information not required by NI 51-101 has been presented to provide continuity and additional information, which Headwater believes is important to the readers of this information.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There are numerous uncertainties inherent in estimating quantities of NGLs, natural gas, shale gas and heavy crude oil reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. The recovery and reserve estimates of the NGLs, natural gas, shale gas and heavy crude oil reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual NGLs, natural gas, shale gas and heavy crude oil reserves may be greater than or less than the estimates provided herein. In general, estimates of economically recoverable NGLs, natural gas, shale gas and heavy crude oil reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of NGLs, natural gas, shale gas, heavy crude oil, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, among others, estimates of the economically recoverable NGLs, natural gas, shale gas and heavy crude oil reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves may vary and such variations may be material. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves associated with the Corporation's assets may vary from the information presented herein and such variations could be material.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices "A" and "B" hereto, respectively.

Headwater's reserves are located in the Marten Hills area of Alberta, Canada and in the McCully Field in New Brunswick, Canada. Please note that rounding errors may occur in the tables set forth below in this Statement of Reserves Data and Other Oil and Gas Information.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2020
FORECAST PRICES AND COSTS

Reserve Category	Conventional Natural Gas		Shale Natural Gas		Heavy Crude Oil		Natural Gas Liquids		Total Oil Equivalent	
	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf))	Gross (MBbl)	Net (MBbl))	Gross (MBbl)	Net (MBbl)	Gross (MBoe)	Net (MBoe)
PROVED										
Developed Producing	16,057	15,714	831	813	2,181	1,794	17	17	5,013	4,565
Developed Non-Producing	-	-	989	968	-	-	1	1	166	162
Undeveloped	3,099	2,720	-	-	3,673	3,077	128	97	4,317	3,628
TOTAL PROVED	19,157	18,434	1,820	1,781	5,854	4,871	146	115	9,495	8,354
PROBABLE										
Developed Producing	4,206	4,116	226	221	841	680	4	4	1,585	1,407
Developed Non-Producing	-	-	298	292	-	-	-	-	50	49
Undeveloped	1,507	1,323	-	-	1,637	1,319	62	45	1,950	1,584
TOTAL PROBABLE	5,713	5,439	524	513	2,478	1,999	67	50	3,584	3,040
TOTAL PROVED PLUS PROBABLE	24,869	23,873	2,344	2,294	8,332	6,870	212	164	13,080	11,395

Note:

(1) Columns may not add due to rounding.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2020
FORECAST PRICES AND COSTS[(1)]

RESERVES CATEGORY	Before Income Tax Discounted at (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)	After Income Taxes Discounted at (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
PROVED										
Developed Producing	115,342	100,966	87,807	77,538	69,629	115,342	100,966	87,807	77,538	69,629
Developed Non-Producing	1,430	1,343	1,231	1,118	1,012	1,430	1,343	1,231	1,118	1,012
Undeveloped	60,474	48,962	39,502	31,791	25,500	60,474	48,962	39,502	31,791	25,500
TOTAL PROVED	177,246	151,270	128,541	110,447	96,141	177,246	151,270	128,541	110,447	96,141
PROBABLE										
Developed Producing	42,878	29,506	21,231	16,213	12,960	42,878	29,506	21,231	16,213	12,960
Developed Non-Producing	438	358	287	229	184	438	358	287	229	184
Undeveloped	51,124	40,102	32,279	26,718	22,688	42,735	34,821	28,850	24,430	21,125
TOTAL PROBABLE	94,439	69,966	53,796	43,160	35,832	86,050	64,686	50,367	40,872	34,269
TOTAL PROVED PLUS PROBABLE	271,686	221,236	182,337	153,607	131,973	263,297	215,956	178,908	151,320	130,410

Note:

(1) The estimated values of future net revenues disclosed do not represent fair market value.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as at December 31, 2020
FORECAST PRICES AND COSTS[(1)]

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOP-MENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS[(2)] ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	FUTURE INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Proved Reserves	414,866	48,359	114,436	47,897	26,928	177,246	-	177,246
Proved Plus Probable Reserves	588,345	73,919	165,120	48,005	29,615	271,686	8,389	263,297

Notes:

(1) The estimated values of future net revenues disclosed do not represent fair market value.
(2) Reflects estimated abandonment and reclamation costs for wells (both existing and undrilled wells) with attributed reserves and for wells with no attributed reserves, facilities and infrastructure.

FUTURE NET REVENUE
BY PRODUCTION TYPE
as of December 31, 2020
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000's)[2]	UNIT VALUE[3] ($)/BOE
Proved Reserves	Conventional Natural Gas[1]	48,122	18.26
	Shale Gas[1]	3,423	11.46
	Heavy Crude Oil[1]	76,996	14.20
	Total[2]	128,541	15.39
Proved Plus Probable Reserves	Conventional Natural Gas[1]	56,215	16.91
	Shale Gas[1]	3,990	10.38
	Heavy Crude Oil[1]	122,132	15.89
	Total[2]	182,337	16.00

Notes:

(1) Including by-products (including NGLs). The GLJ Report does not separately report on the Future Net Revenue for NGLs.
(2) Columns may not add due to rounding.
(3) Unit values are based on net reserve volumes.

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2020, reflected in the Reserves Data. The forecast of prices, inflation and exchange rates provided in the table below were computed using the average of the forecasts by GLJ, McDaniel & Associates Ltd. and Sproule Associates Limited effective as at January 1, 2021.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS[1]
as of December 31, 2020
FORECAST PRICES AND COSTS

	Crude Oil					
Year	**WTI Cushing Oklahoma (US$/Bbl)**	**Light Sweet Crude Oil at Edmonton 40º API (Cdn$/Bbl)**	**Bow River Crude Oil at Hardisty (Cdn$/Bbl)**	**WCS Crude Oil at Hardisty (Cdn$/Bbl)**	**Pentanes Plus Edmonton (Cdn$/bbl)**	**Butanes Price Edmonton (Cdn$/bbl)**
Forecast[4]						
2021	47.17	55.76	45.36	44.63	59.24	26.36
2022	50.17	59.89	48.96	48.18	63.19	32.85
2023	53.17	63.48	52.92	52.10	67.34	39.20
2024	54.97	65.76	54.95	54.10	69.77	40.65
2025	56.07	67.13	56.05	55.19	71.18	41.50
2026	57.19	68.53	57.16	56.29	72.61	42.36
2027	58.34	69.95	58.30	57.42	74.07	43.24
2028	59.50	71.40	59.47	58.57	75.56	44.14
2029	60.69	72.88	60.66	59.74	77.08	45.06
2030	61.91	74.34	61.87	60.93	78.62	45.96
2031	63.15	75.83	63.11	62.15	80.19	46.88
Thereafter escalation rate of 2.0%						

Year	Natural Gas AECO-C Spot (Cdn$/MMBtu)	NYMEX Henry Hub (US$/MMBTU)	AGT Gas Price (US$/MMbtu)	McCully Gas Price[2] (Cdn$/Mcf)	Inflation Rates %/Year	Exchange Rate [3] (US$/Cdn$)
	Natural Gas					
Forecast[4]						
2021	2.78	2.83	3.58	6.47	0.0	0.7683
2022	2.70	2.87	3.87	6.47	1.3	0.7650
2023	2.61	2.90	3.85	6.51	2.0	0.7633
2024	2.65	2.96	3.86	5.74	2.0	0.7633
2025	2.70	3.02	3.97	6.37	2.0	0.7633
2026	2.76	3.08	4.05	6.50	2.0	0.7633
2027	2.81	3.14	4.13	6.63	2.0	0.7633
2028	2.86	3.20	4.20	6.75	2.0	0.7633
2029	2.92	3.26	4.26	6.98	2.0	0.7633
2030	2.98	3.33	4.33	7.12	2.0	0.7633
2031	3.04	3.39	4.39	7.23	2.0	0.7633
Thereafter escalation rate of 2.0%						

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.

(2) The forecast McCully gas price is used by GLJ in calculating the net present value of Headwater's future natural gas net revenues from the McCully Field. The McCully gas price is determined by adjusting the forecast AGT gas prices to reflect the expected premiums received at Headwater's delivery point, transportation costs, as applicable, heat content and marketing conditions. The McCully gas price in years 2021 – 2023 reflects only the winter producing months (January to April and November to December) to correlate to the intermittent production strategy employed by the Corporation to capture seasonal premium pricing. After 2023, the GLJ Report assumes Headwater produces volumes from its reserves continuously over the year and as such, McCully pricing reflects the full year.

(3) The exchange rate used to generate the benchmark reference prices in this table.

(4) As at December 31, 2020.

The weighted average historical prices realized, before financial derivative contracts, by the Corporation for the year ended December 31, 2020 were $3.21/Mcf for natural gas and $57.28/bbl for NGLs. The weighted average historical price realized before blending and transportation expense was $48.87/bbl for heavy crude oil

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of the gross reserves of the Corporation as at December 31, 2020 as compared to December 31, 2019:

Reserves Reconciliation of Corporation Total Reserves
By Principal Product Type
(Forecast Prices and Costs)

FACTORS	Conventional Natural Gas Gross Proved (MMcf)	Conventional Natural Gas Gross Probable (MMcf)	Conventional Natural Gas Gross Proved Plus Probable (MMcf)	Shale Natural Gas Gross Proved (MMcf)	Shale Natural Gas Gross Probable (MMcf)	Shale Natural Gas Gross Proved Plus Probable (MMcf)	Heavy Crude Oil Gross Proved (Mbbl)	Heavy Crude Oil Gross Probable (Mbbl)	Heavy Crude Oil Gross Proved Plus Probable (Mbbl)
December 31, 2019[(1)]	17,163	3,921	21,084	836	197	1,034	-	-	-
Extension and Improved Recovery	3,099	1,507	4,606	989	298	1,287	22	31	52
Technical Revisions	249	285	534	30	29	60	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	5,922	2,448	8,370
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(1,355)	-	(1,355)	(36)	-	(36)	(90)	-	(90)
December 31, 2020[(2)]	19,157	5,713	24,869	1,820	524	2,344	5,854	2,478	8,332

Reserves Reconciliation of Corporation Reserves
By Principal Product Type
(Forecast Prices and Costs)

FACTORS	Natural Gas Liquids Gross Proved (MBbl)	Natural Gas Liquids Gross Probable (MBbl)	Natural Gas Liquids Gross Proved Plus Probable (MBbl)	Total Oil Equivalent Gross Proved (MBOE)	Total Oil Equivalent Gross Probable (MBOE)	Total Oil Equivalent Gross Proved Plus Probable (MBOE)
December 31, 2019[(1)]	18	4	22	3,018	690	3,709
Extensions and Improved Recovery	129	62	191	831	394	1,225
Technical Revisions	-	-	-	46	53	99
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	5,922	2,448	8,370
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(1)	-	(1)	(323)	-	(323)
December 31, 2020[2)]	146	67	212	9,495	3,584	13,080

Notes:

(1) As evaluated by GLJ as at December 31, 2019, using the average of the forecasts by GLJ, McDaniel & Associates Ltd. and Sproule Associates Limited and costs as at such date.
(2) As evaluated in the GLJ Report.
(3) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation's assets for the years ended December 31, 2020, 2019 and 2018 and also the remaining cumulative proved undeveloped reserves and the probable undeveloped reserves as at the end of such years.

Proved Undeveloped Reserves

Year	Conventional Natural Gas (MMcf)		Shale Natural Gas (MMcf)		Heavy Crude Oil (Mbbl)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
2020	3,099	3,099	-	-	3,673	3,673	128	128	4,317	4,317

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.
(3) The Corporation did not have proved undeveloped reserves in 2018 or 2019.

Probable Undeveloped Reserves

Year	Conventional Natural Gas (MMcf)		Shale Natural Gas (MMcf)		Heavy Crude Oil (Mbbl)		Natural Gas Liquids (Mbbl)		Oil Equivalent (MBOE)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-
2020	1,507	1,507	-	-	1,637	1,637	62	62	1,950	1,950

Notes:

(1) "First Attributed" refers to reserves first attributed at the year end of the corresponding fiscal year.
(2) Columns may not add due to rounding.
(3) The Corporation did not have any probable undeveloped reserves in 2018 or 2019.

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.

On May 27, 2016, the Government of New Brunswick announced its decision to continue the moratorium on hydraulic fracturing for an indefinite period. Headwater believes that all undeveloped wells in the McCully Field require hydraulic fracture stimulation to be commercially productive. As a result of this announcement, Headwater's undeveloped wells requiring hydraulic fracture stimulations in New Brunswick no longer meet the necessary conditions to qualify as reserves and GLJ made the decision in June 2016 to eliminate all undeveloped reserves from its estimates of reserves.

The Corporation completed the acquisition of the Acquired Assets on December 2, 2020 and as such certain undeveloped proved and probable reserves were attributed as at December 31, 2020 to the Acquired Assets. The Corporation plans to develop all of its proved and probable undeveloped reserves within two years; however, these locations will continue to be re-evaluated to assess their relative economic merits when compared to other projects available to the Corporation. Undeveloped reserves planned to be developed beyond two years are scheduled in that manner due to various factors including access to capital, limitations on egress and pricing uncertainty.

See "*Risk Factors – Hydraulic Fracturing*" and "*Risk Factors – Exploration, Development and Production Risks*" and other factors noted in "*Risk Factors*".

Significant Factors or Uncertainties

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 gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions.

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

In addition, higher than estimated operating costs would substantially reduce Headwater netback, which in turn would reduce the amount of cash available for reinvestment in drilling opportunities. This becomes most relevant during periods of low commodity prices when profits are more significantly impacted by high costs.

On March 27, 2015, the Government of New Brunswick enacted *An Act to Amend the Oil and Natural Gas Act* which created a moratorium on all forms of hydraulic fracturing in New Brunswick. On May 27, 2016, the New Brunswick Government announced its decision to continue the moratorium for an indefinite period, though recent amendments suggest that exemptions may be available for operations in the Sussex region. Headwater believes that all undeveloped wells on its properties in New Brunswick require hydraulic fracture stimulation to be commercially productive. As a result of this announcement, Headwater has determined that it will not undertake any drilling or completion activities or incur associated capital expenditures in New Brunswick until the moratorium is lifted. As a result, Headwater's undeveloped wells in New Brunswick requiring hydraulic fracturing no longer meet the necessary conditions to qualify as reserves. See "*Risk Factors – Hydraulic Fracturing*", "*Risk Factors – Exploration, Development and Production Risks*" and other factors noted in "*Risk Factors*".

Additional Information about Abandonment and Reclamation Costs

The total future abandonment and site reclamation costs are based on information published by the AER with respect to AER Licensee Liability Management Program in Alberta (in respect of the Corporation's Alberta assets) and standard engineering techniques and management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to Headwater's working interest and the estimated timing of the costs to be incurred in future periods. Headwater has developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type of well or facility and geographic location. GLJ has determined that Headwater's estimates of its abandonment and reclamation costs are reasonable and have included these costs in the GLJ Report. All costs associated with the process of restoring the Corporation's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities have been deducted for the purposes of calculating the net present value of the future net revenue associated with the Corporation's reserves.

Headwater estimates that the total cost to abandon and reclaim all wells with reserves, wells with no attributed reserves and related facilities as of December 31, 2020 is approximately $15.5 million on an undiscounted, uninflated basis. The abandonment and reclamation costs in the McCully Field include 32.5 net wells, the gas processing plant and transmission pipeline in New Brunswick and in the Marten Hills area of Alberta the estimate includes 19.0 net wells and related multi-well battery infrastructure.

The GLJ Report included the full estimated undiscounted future abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Headwater's proved plus probable reserves, approximately $29.6 million (undiscounted) has been deducted in estimating the future net revenue in the GLJ Report, which represents the Corporation's total existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

Additional information related to the Corporation's estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities and infrastructure) can be found in Headwater's audited financial statements for the year ended December 31, 2020 and the accompanying management's discussion and analysis, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com.

Future Development Costs

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

	Forecast Prices and Costs	
Year	**Proved Reserves ($M)**	**Proved Plus Probable Reserves ($M)**
2021	41,230	41,230
2022	3,979	3,979
2023	-	-
2024	-	-
2025	-	-
Thereafter	2,687	2,796
Total: Undiscounted	47,897	48,005
Discounted 10%	44,046	43,843

The future development costs for both proved and proved plus probable reserves are expected to be funded through future cash flow and from the Corporation's existing working capital. Headwater's anticipated capital expenditures in 2021 include anticipated costs for exploration and development activities in the Marten Hills area of $90 to $95 million which is in excess of the future development costs utilized for estimating the future net revenue of both the Corporation's proved and proved plus probable reserves as set out in the GLJ Report. The 2021 capital expenditure budget includes expenditures for development drilling, exploration drilling, infrastructure and land costs that are not contained in the GLJ Report. Headwater's capital program does not include any new acquisition opportunities, which would likely be financed through existing working capital or debt or equity financings, if necessary. Headwater may also consider issuing Common Shares or other securities as consideration for future acquisitions.

Headwater's 2021 capital expenditure program includes insignificant capital spending in New Brunswick due to the hydraulic fracturing moratorium currently in effect in New Brunswick. Future development capital after 2022 is associated with McCully gas plant optimization.

There can be no guarantee that funds will be available or that the Board will allocate funding to develop all of the reserves attributable in the GLJ Report. Failure to develop those reserves may have a negative impact on Headwater's future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and may reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. Headwater does not anticipate that interest or other funding costs would make further development of any of the NGLs, natural gas, shale gas and heavy crude oil assets uneconomic.

Factors that could result in the change in timing or cancelled future developments are as follows:

- unanticipated facility failure that would change the timing of capital expenditures; and
- changing production conditions (such as producing pressures declining greater than anticipated, causing the need for more facility compression).

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

Other Oil and Gas Information

Description of Principal Properties

Marten Hills, Alberta

The Marten Hills area is located approximately 250 kilometres north of Edmonton, Alberta and targets conventional heavy oil from the Clearwater formation. The Corporation's interests in the Marten Hills area consists of approximately 189,798 net acres, including approximately 172,800 acres or 270 net sections of Clearwater rights. The Corporation also acquired approximately 2,800 barrels per day of heavy oil production.

The Clearwater formation is characterized as a conventional reservoir, with variability throughout, but in general is an oil-bearing formation of approximately 15 meters in thickness. The Clearwater formation's reservoir characteristics provide for development under the application of open-hole multi-lateral wells targeted at a vertical depth of approximately 500 to 800 meters. There is also the potential for waterfloods and polymer floods to augment the resource, increasing recovery potential.

The Acquired Assets included 17 net producing wells, 2 net non-producing wells and 4 multi-well batteries. The Corporation plans to significantly expand on the pre-existing infrastructure in the area in 2021/2022 by building gathering lines, an oil processing facility and partnering in the development of a gas plant, all of which are expected to significantly reduce future operating and transportation costs. Headwater spent $1.8 million on the Acquired Assets in 2020 in anticipation of the 2021 drilling season. In 2021, the Corporation plans to embark on an exploration and development capital program in the Marten Hills area of $90 to $95 million. The Corporation has allocated approximately $60 million towards the drilling of 24 8-leg multi-lateral wells, 25 injector wells, 2 source wells and 1 stratigraphic test well, approximately $25 to $30 million on infrastructure and $5 million on land and seismic.

The Corporation's heavy oil production (average 18 - 22˚ API) must be blended with diluent during the winter months to reduce the viscosity of the heavy oil to meet downstream pipeline specifications. The Acquired Assets contributed 246 barrels per day of heavy oil production for the year ended December 31, 2020. The Corporation's realized price received for its heavy crude oil is determined by the quality of the crude compared to the benchmark reference price of WCS.

In connection with the completion of the Cenovus Transaction, Headwater assumed certain transportation commitments from CMHP and entered into both the Development Agreement and the Royalty Agreement with CMHP. The transportation commitments are long-term in nature and secure the Corporation market access for its heavy oil production. Pursuant to the Development Agreement, Headwater committed to spend $100 million in capital expenditures on the Acquired Assets by December 31, 2022, unless otherwise extended by CMHP. Pursuant to the Royalty Agreement, Cenovus retained a gross overriding royalty on the lands comprising the Acquired Assets. For details of the Corporation's transportation commitments as well as the Development Agreement and Royalty Agreement, see the Corporation's audited annual financial statements for the year ended December 31, 2020, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com.

The GLJ Report assigned gross proved plus probable reserves of 9.3 MMboe of heavy oil and natural gas reserves within the Marten Hills area as at December 31, 2020.

The Acquired Assets are also characterized by positive environmental, social and governance attributes including minimal abandonment and reclamation liability, reduced freshwater usage as no hydraulic fracture stimulation is required and a decreased environmental footprint due to pipeline connected multi-well pad development.

McCully Field

The McCully Field, located approximately 12 kilometres northeast of Sussex, New Brunswick, includes natural gas production from the Hiram Brook formation, a conventional tight sandstone, and a portion of the Frederick Brook shale, an unconventional shale resource.

The Corporation's interests in the McCully Field consist of the following petroleum and natural gas leases:

- 100% working interest in lease number 06-01 (40,930 acres).
- 50% working interest in lease number 06-02 (3,561 gross acres and 1,780 net acres).
- 50% working interest in lease number 09-01 (36,531 gross acres and 18,265 net acres held jointly with Nutrien).
- 100% working interest in lease number 13-02C (135,920 gross acres).

As at the date hereof, 39 wells have been drilled in the McCully Field, all of which have encountered natural gas.

Headwater sells all of its share of the natural gas produced from the McCully Field to Repsol pursuant to a long-term agreement which became effective on April 1, 2009 and will terminate on April 1, 2024. Headwater's natural gas production has historically been sold in the New England market in the northeastern U.S. at prices referenced to AGT but has recently been expanded to include sales to local markets in the Maritimes given the decrease in natural gas production in Atlantic Canada. In 2018, Headwater and Repsol amended their long-term agreement to eliminate transportation charges on the Canadian portion of the M&NP from November 1, 2018 to April 1, 2024 in recognition of the changing market.

The production, transportation, processing and marketing of natural gas from Nutrien's share of the production from the McCully Field are subject to agreements with Nutrien. Nutrien's share of natural gas production is either taken in kind for use at the Nutrien potash mill, located near Sussex, New Brunswick or delivered to Headwater's midstream facilities for sale by Nutrien to the Maritimes market and New England market.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2020 in which Headwater has a working interest. All of the wells in which Headwater has an interest are located in the Province of Alberta and onshore in the Province of New Brunswick.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
New Brunswick	-	-	1.0	1.0	32.0	24.5	8.0	7.0
Alberta	17.0	17.0	2.0	2.0	-	-	-	-
Total	17.0	17.0	3.0	3.0	32.0	24.5	8.0	7.0

Properties with no Attributed Reserves

The following table sets out the developed and undeveloped land holdings of Headwater as at December 31, 2020.

	Undeveloped Acres		**Developed Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
New Brunswick	209,823	191,556	7,118	5,338	216,941	196,894
Québec	123,550	123,550	-	-	123,550	123,550
Saskatchewan	14,893	14,893	-	-	14,893	14,893
Alberta	183,451	183,451	6,347	6,347	189,798	189,798
Total	531,717	513,450	13,465	11,685	545,182	525,135

Headwater surrendered approximately 123,550 net acres of undeveloped land in the Old Harry prospect in the Laurentian Channel in Québec in February 2021. In Alberta, Headwater expects to allow 640 net acres to expire in July 2021.

No other rights to explore, develop and exploit undeveloped land holdings will expire before December 31, 2021.

Forward Contracts

Headwater's operational results and financial condition will be dependent upon the prices received for its heavy crude oil NGLs, natural gas and shale gas production. Heavy crude oil, NGLs, natural gas and shale gas prices have fluctuated widely in recent years. Any upward or downward movement in heavy crude oil NGLs, natural gas and shale gas prices could have an effect on Headwater financial condition. For details on the various factors affecting oil and natural gas prices, see "*Industry Conditions – Pricing and Marketing*".

Headwater's hedging activities could expose Headwater to losses or gains. Headwater could be subject to credit risk associated with the parties with which it contracts. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of Headwater's exposure to these entities. For details of the Corporation's forward contracts see the Corporation's audited annual financial statements for the year ended December 31, 2020, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com. See "*Risk Factors – Hedging*".

Tax Horizon

Headwater has approximately $263 million of tax pools available, consisting primarily of Canadian Exploration Expense, Canadian Development Expense, Canadian Oil and Gas Property Expense, Facilities and Equipment (Class 41), Transmission Pipeline (Class 1) and Other Equipment, CEC and non-capital losses. No cash income taxes were recorded for the year ended December 31, 2020. Based upon Headwater's planned capital expenditures and various other assumptions, no cash income taxes are expected to be paid by Headwater in 2021. The level of capital expenditures and additional acquisitions completed by the Corporation, as well as a variety of other factors, impact the Corporation's tax horizon. Additional spending could extend the Corporation's tax horizon.

Exploration and Development Activities

Headwater incurred minimal capital expenditures related to exploration or development activities in New Brunswick during the year ended December 31, 2020 and does not have any plans to conduct significant exploration and development activities in New Brunswick until the moratorium on hydraulic fracturing in New Brunswick is lifted.

Headwater incurred exploration or development expenditures of approximately $1.8 million in Alberta during the year ended December 31, 2020 in relation to site preparation for the 2021 drilling season and in 2021 plans to embark on an exploration and development capital program in the Marten Hills area of $90 to $95 million that is expected to result in the drilling of 24 8-leg multi-lateral wells, 25 injector wells, 2 source wells and 1 stratigraphic test well. See "*Statement of Reserves Data and Other Oil and Gas Information – Description of Principal Properties*".

Costs Incurred

The following tables summarize capital expenditures (excluding capitalized general and administrative and other expenses) related to activities attributable to the Corporation's oil and gas assets for the year ended December 31, 2020:

($ thousands)	**December 31, 2020**
Property Acquisition (1)	
Proved Properties	6,144
Unproved Properties	26,637
Exploration Costs	388
Development Costs	1,752
Dispositions	-
Total capital expenditures	34,921

Note:

(1) Includes the portion of the consideration for the Acquired Assets paid in cash. The Cenovus Transaction was completed for total consideration of $135.3 million, comprised of $32.8 million of cash, $96.5 million of Common Shares valued using Headwater's closing share price on the closing date of the Cenovus Transaction of $1.93 and $6 million attributed to the Cenovus Warrants.

Production Estimates

The following table sets out the volume of working interest production estimated for the year ended December 31, 2021, which is reflected in the estimate of future net revenue for the Corporation's gross proved reserves and gross proved plus probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Conventional Natural Gas (Mcf/d)	**Shale Natural Gas (Mcf/d)**	**Heavy Crude Oil (Bbls/d)**	**Natural Gas Liquids (Bbls/d)**	**Total (BOE/d)**
Proved					
Developed Producing	3,730	121	2,301	4	2,947
Developed Non-Producing	-	223	-	-	37
Undeveloped	684	-	1,109	28	1,251
Total Proved	4,414	344	3,410	32	4,235
Total Probable	125	1	440	4	465
Total Proved Plus Probable	4,539	345	3,850	36	4,700

The gross production estimated for the year ended December 31, 2021 reflected in the estimate of future net revenue for the Corporation's gross P+P Reserves from the Marten Hills area of Alberta is 3,850 Bbls/d of heavy oil and 779 Mcf/d of natural gas**.** The gross production estimated for the year ended December 31, 2021 reflected in the estimate of future net revenue for the Corporation's gross P+P Reserves from the McCully Field in New Brunswick is 4,105 Mcf/d of natural gas and 36 Bbls/d of NGLs.

Production History

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

	Quarter Ended 2020				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2020
Average Daily Production[1]					
Natural Gas (MMcf/d)	8.9	2.4	-	4.0	3.8
NGLs (bbls/d)	7	-	-	3	3
Heavy Crude Oil (bbls/d)	-	-	-	979	246
Combined (BOE/d)	1,487	396	-	1,646	882
Average Net Production Prices Received [2]					
Natural Gas ($/Mcf)	7.36	2.27	-	9.68	7.18
NGLs ($/bbl)	57.90	-	-	56.23	57.28
Heavy Crude Oil ($/bbl)	-	-	-	36.47	36.47
Combined ($/BOE)	44.21	13.63	-	45.22	41.27
Royalties Paid [4]					
Natural Gas ($/Mcf)	0.07	0.07	-	0.12	0.08
Natural gas liquids ($/bbl)	-	-	-	-	-
Heavy Crude Oil ($/bbl)	-	-	-	6.01	6.01
Combined ($/BOE)	0.42	0.39	-	3.86	2.03
Production Costs[3] [4]					
Natural Gas ($/Mcf)	0.80	2.47	-	1.61	1.65
Natural gas liquids ($/bbl)	-	-	-	-	-
Heavy Crude Oil ($/bbl)	-	-	-	6.77	6.77
Combined ($/BOE)	4.78	14.80	-	7.92	8.98
Netback Received					
Natural Gas ($/Mcf)	6.49	(0.27)	-	7.95	5.45
Natural gas liquids ($/bbl)	57.90	-	-	56.23	57.28
Heavy Crude Oil ($/bbl)	-	-	-	23.69	23.69
Combined ($/BOE)	39.01	(1.56)	-	33.44	30.26

Notes:

(1) Before deduction of royalties.
(2) Production prices are after hedging and net of costs to blend and transport the product to market and do not include revenue from gathering, processing and transportation.
(3) This figure includes all field production expenses.
(4) Headwater did not record royalties and production costs for NGLs as Headwater only had nominal sales of NGLs in 2020 and therefore information is included in the combined BOE.

In 2020, the principal property that the Corporation derived most of its production from was the McCully Field. The gross working interest production from the McCully Field in 2020 was 3.8 MMcf/d of natural gas and 3 Bbls/d of NGLs. The Corporation acquired the Acquired Assets on December 2, 2020 and as such the production from the Marten Hills area contributed 246 Bbls/d to the Corporation's total production in 2020**.**

DIRECTORS AND EXECUTIVE OFFICERS OF THE CORPORATION

The names, provinces and countries of residence of each of the directors and executive officers of the Corporation, positions held with the Corporation, and the period each has served as a director or executive officer of the Corporation are as follows:

Name and Place of Residence	Office Held
Neil J. Roszell Alberta, Canada	Chairman, Chief Executive Officer and a Director (since March 4, 2020)
Jason Jaskela Alberta, Canada	President, Chief Operating Officer and a Director (since March 4, 2020)

Name and Place of Residence	Office Held
Ali Horvath, CPA, CA Alberta, Canada	Vice President, Finance and Chief Financial Officer (since March 4, 2020)
Terry Danku Alberta, Canada	Vice President, Engineering (since March 4, 2020)
Jon Grimwood Alberta, Canada	Vice President, Exploration (since March 4, 2020)
Scott Rideout Alberta, Canada	Vice President, Land (since March 4, 2020)
Brad Christman Alberta, Canada	Vice President, Production (since April 1, 2020)
Chandra Henry(1), CPA, CFA, ICD.D Alberta, Canada	Director (since March 4, 2020)
Phillip Knoll(3), P.Eng Alberta, Canada	Director (since September 21, 2010)
Stephen Larke(2), B. Comm, ICD.D Alberta, Canada	Director (since March 4, 2020)
Kevin Olson(1)(3) Alberta, Canada	Lead Independent Director (since March 4, 2020)
David Pearce(2)(3) Alberta, Canada	Director (since March 4, 2020)
Kam Sandhar(1) Alberta, Canada	Director (since December 2, 2020)
Sarah Walters(2) Alberta, Canada	Director (since December 2, 2020)
Edward (Ted) Brown Alberta, Canada	Corporate Secretary (since March 4, 2020)

Notes:

(1) Member of the Audit Committee.
(2) Member of Corporate Governance and Sustainability Committee.
(3) Member of the Reserves Committee.

Headwater's directors will hold office until the next annual general meeting of the Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

As at March 10, 2021, the directors and executive officers of Headwater, as a group, beneficially owned or controlled or directed, directly or indirectly, 14,360,627 Common Shares or approximately 7.4% of the issued and outstanding Common Shares.

Principal Occupation

Profiles of the directors and executive officers of Headwater and the particulars of their respective principal occupations during the last five years are set forth below.

Neil Roszell, Chairman, Chief Executive Officer and a Director

Mr. Roszell is a professional engineer with 30+ years of industry experience. Mr. Roszell was the President and Chief Executive Officer of Raging River Exploration Inc. ("**Raging River**") from 2012 until June 5, 2017 when he transitioned into the role of Executive Chairman and Chief Executive Officer until Raging River's sale to Baytex Energy Corp. ("**Baytex**") in August 2018, following which Mr. Roszell acted as Chairman of Baytex from August 2018 until December 2019. Mr. Roszell was the President and Chief Executive Officer of Wild Stream Exploration Inc. ("**Wild Stream**") from 2009 to 2012. He was also the President and Chief Executive Officer of Wild River Resources Ltd. ("**Wild River**") from 2007 until 2009. Mr. Roszell was the President and Chief Operating Officer of Prairie Schooner Energy Ltd. ("**Prairie Schooner**") from August 2004 until September 2006. Mr. Roszell was Vice President, Engineering of Great Northern Exploration Ltd. from September 2001 to June 2004. Mr. Roszell received a Bachelor of Applied Science degree in Engineering from the University of Regina in 1991.

Jason Jaskela, President, Chief Operating Officer and a Director

Mr. Jaskela is a professional engineer with 21 years of industry experience. Mr. Jaskela was the Vice President, Production of Raging River from March 2012 until March 17, 2014 when he expanded his role to Chief Operating Officer and held that position until Raging River's sale to Baytex in August 2018, following which he was the Executive Vice President and Chief Operating Officer at Baytex until September 2020. From October 2009 to April 2010 he held the position of Manager Engineering with Wild Stream and was the Vice President, Production of Wild Stream from April 2010 until 2012. Prior to Wild Stream, Mr. Jaskela held senior engineering roles with Encana Corporation (May 2000 to May 2006) and Mahalo Energy Ltd. (May 2006 to October 2009). Mr. Jaskela graduated with a Bachelor of Science degree in Engineering in 2000.

Ali Horvath, Chief Financial Officer and Vice President, Finance

Ms. Horvath has over 10 years of management, accounting and corporate finance experience. Ms. Horvath was previously a founder and the Controller of Raging River and prior thereto a Senior Financial Accountant with Wild Stream. Prior to Wild Stream, Ms. Horvath worked in the audit and assurance practice of PricewaterhouseCoopers LLP. Ms. Horvath has a Bachelor of Management degree from the University of Lethbridge. Ms. Horvath is a Chartered Professional Accountant.

Terry Danku, Vice President, Engineering

Mr. Danku is a professional engineer with 19 years of industry experience. Mr. Danku held several officer positions at Raging River 2014 through 2018, including Vice-President, Engineering, Vice-President, Business Development and Vice-President, Exploitation. Previously, Mr. Danku held a Team Lead position at Surge Energy Inc. ("**Surge**") and Senior engineering roles at Pace Oil & Gas (April 2012 – October 2013), Wild Stream (May 2011 – March 2012) and Encana Corporation (July 2002 – April 2011). Mr. Danku graduated with a Bachelor of Science degree in Engineering in 2002.

Jon Grimwood, Vice President, Exploration

Mr. Grimwood was the Vice President of Exploration at Raging River from October 2, 2017 until Raging River's sale to Baytex in August 2018, following which Mr. Grimwood was the Vice President of Exploration at Baytex until September 2019. Mr. Grimwood served as the President at Iron Bridge Resources Ltd. (formerly known as RMP Energy Inc. and Orleans Energy Ltd.) from February 28, 2017 to August 1, 2017 and also served as its Vice President, Exploration from May 2011 to February 28, 2017. He started his career at Poco Petroleums Ltd. in 1997 and held positions of increasing responsibility at Burlington Resources Canada Ltd., Rider Resources Ltd., and Galleon Energy

Inc. Mr. Grimwood earned a Bachelor of Science from Brandon University, a Masters Degree in Earth Sciences from the University of Waterloo and is a Registered Member of APEGGA.

Scott Rideout, Vice President, Land

Mr. Rideout is a landman with over 18 years of industry experience. Mr. Rideout was the Vice President, Land at Raging River from July 2014 until Raging River's sale to Baytex in August 2018, following which Mr. Rideout was the Vice President, Land at Baytex until January 2020. Mr. Rideout held roles of increasing responsibility at Surge from October 2010 until July 2014 where he most recently held the position of Manager, Business Development and Land. Prior to joining Surge he was a Land Negotiator at Galleon Energy Inc., Kereco Energy Ltd., Provident Energy Trust and Talisman Energy Inc.

Brad Christman, Vice President, Production

Mr. Christman has 20 years of industry experience in Canada and in the United States. Mr. Christman was the Manager, Production and Facilities at Raging River from March 2012 until Raging River's sale to Baytex in August 2018, following which Mr. Christman was the Manager, Production and Facilities at Baytex until March 2020. Prior to Raging River, Mr. Christman worked as an Area Coordinator at Wild Stream.

Chandra Henry, Director

Ms. Henry is currently Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc. and a director of Bonavista Energy Corporation. Ms. Henry was formerly a director of Pengrowth Energy Corporation. Prior to her role with Longbow, Ms. Henry was the Chief Financial Officer of FirstEnergy Capital Corp. Ms. Henry has a Bachelor of Commerce degree from the University of Calgary and has earned the Chartered Professional Accountant (CPA, CA), Chartered Financial Analyst (CFA) and Institute of Corporate Directors (ICD.D) designations.

Phillip Knoll, Director

Mr. Knoll is a Professional Engineer and has been the President of Knoll Energy Inc. since 2006. Mr. Knoll currently serves on the Board of Altagas Ltd. and was formerly a director of Rally Energy Corp and Bankers Petroleum. Mr. Knoll served as interim Co-CEO of AltaGas Ltd. from July to December 2018. He was CEO of Headwater (formerly Corridor Resources Inc.) from October 2010 to September 2014. Prior thereto, Mr. Knoll held senior roles with a number of companies, including Duke Energy Gas Transmission, Maritimes & Northeast Pipeline, Westcoast Energy Inc., TransCanada Pipelines Limited and Alberta Natural Gas Company Ltd.

Stephen Larke, Director

Mr. Larke has over 20 years of experience in energy capital markets, including research, sales, trading and equity finance and currently serves on the board of Topaz Energy Corp. and Vermillion Energy Inc. He is formerly a Managing Director and Executive Committee member with Calgary-based Peters & Co. Limited. Mr. Larke has a Bachelor of Commerce degree (Distinction) from the University of Calgary and has earned the Chartered Financial Analyst (CFA) and Institute of Corporate Directors (ICD.D) designations. In addition, Mr. Larke is a Fundamentals of Sustainability Accounting (FSA) Credential Holder.

Kevin Olson, Director

Mr. Olson has over 25 years of industry experience. Mr. Olson is a former board member of Baytex, Raging River, Wild Stream, Wild River and Prairie Schooner Petroleum Ltd. Mr. Olson has managed four early stage energy funds and served as a director of a variety of exploration and production companies and petroleum services companies. Formerly Mr. Olson was Vice-President, Corporate Finance at FirstEnergy Capital Corp. and Vice-President, Corporate Development for Northrock Resources Ltd. Mr. Olson holds a Bachelor of Commerce degree (Distinction) majoring in finance and accounting from the University of Calgary.

David Pearce, Director

Mr. Pearce has a Bachelor of Science in Mechanical Engineering (Honors) and has been a Deputy Managing Partner at Azimuth Capital Management (formerly KERN Partners) from November 2008 to present. Mr. Pearce is currently a director at Baytex. Mr. Pearce was also a director of Raging River (March 2012) until the sale to Baytex in August 2018). Most recently, Mr. Pearce was with Northrock Resources Ltd. from June 1999 to January 2008 where he held several senior officer positions and most recently was the President and Chief Executive Officer. Prior thereto, Mr. Pearce was Vice President, Corporate Development at Fletcher Challenge Canada.

Kam Sandhar, Director

Mr. Sandhar is currently the Executive Vice-President, Strategy & Corporate Development of Cenovus. Mr. Sandhar has nearly 20 years of experience in the oil and gas industry and has extensive expertise in strategy, business development, finance and investor relations. Prior to joining Cenovus in 2013, Mr. Sandhar spent nine years at Peters & Co. Limited where he served as a Principal and oil and gas analyst, covering a wide array of Canadian, U.S. and international oil and gas companies. Mr. Sandhar started his career at Deloitte LLP where he focused on oil and gas audit and taxation. Mr. Sandhar is a Chartered Professional Accountant and a member of the Chartered Professional Accountants of Alberta. He holds a Bachelor of Commerce degree from the University of Calgary.

Sarah Walters, Director

Ms. Walters is currently the Executive Vice-President, Corporate Services of Cenovus. Ms. Walters has been with Cenovus since 2013 in various executive roles. Ms. Walters has more than 20 years of international strategic human resources and organizational development experience gained within the rail, health service and oil & gas industries. Sarah earned a Master of Science from Dearne Valley Business School in the United Kingdom.

Edward (Ted) Brown, Corporate Secretary

Mr. Brown is a partner in the law firm Burnet, Duckworth & Palmer LLP, where his practice concentrates in corporate finance, mergers and acquisitions and corporate governance. Mr. Brown has a Bachelor of Arts degree in Economics and Bachelor of Laws degree from the University of Manitoba.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No current or proposed director or officer or securityholder holding a sufficient number of securities of Headwater to affect materially the control of Headwater has, within the last ten years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including Headwater) that, (i) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (ii) was subject to an order that resulted, after the director, executive officer or securityholder holding a sufficient number of securities of Headwater to affect materially the control of Headwater ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

No current or proposed director or officer or security holder holding a sufficient number of securities of Headwater to affect materially the control of Headwater has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including Headwater) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

No current or proposed director or officer or securityholder holding a sufficient number of securities of Headwater to affect materially the control of Headwater has, within the last ten years prior to the date of this document, 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, officer or securityholder.

No current or proposed director or officer or securityholder holding a sufficient number of securities of Headwater to affect materially the control of Headwater 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

Some of the directors and officers of the Corporation are also directors, officers and/or promoters of other reporting and non-reporting issuers. Accordingly, conflicts of interest may arise which could influence these persons in evaluating possible acquisitions or in generally acting on behalf of the Corporation, notwithstanding that they are bound by the provisions of the ABCA to act at all times in good faith in the interest of the Corporation and to disclose such conflicts to the Corporation if and when they arise. To the best of their knowledge, the Corporation is not aware of the existence of any conflicts of interest between any of their directors and officers as of the date hereof.

DIVIDENDS

There are no restrictions in the Corporation's articles or elsewhere which could prevent the Corporation from paying dividends. The Corporation has not paid out any dividends on any of its securities since its inception. The directors of the Corporation will determine if, and when, dividends will be declared and paid in the future from funds properly applicable to the payment of dividends based on the Corporation's financial position at the relevant time. Any decision to pay dividends on the Common Shares will be made by the directors on the basis of the Corporation's earnings, financial requirements and other factors existing at such future time, including commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. All of the Common Shares will be entitled to an equal share in any dividends declared and paid.

DESCRIPTION OF SHARE CAPITAL

Common Shares

The authorized capital of the Corporation includes an unlimited number of Common Shares without nominal or par value of which, as at March 10, 2021, 195,410,957 Common Shares are issued and outstanding as fully paid and non-assessable. In addition, the Corporation has 21,423,916 Warrants, 15,000,000 Cenovus Warrants and stock options to purchase 8,620,835 Common Shares outstanding as of March 10, 2021.

The holders of Common Shares are entitled to dividends, if, as and when declared by the Board, to receive notice of and one vote per Common Share at meetings of the shareholders and, upon liquidation, to share equally in such assets of Headwater as are distributable to the holders of Common Shares.

MARKET FOR SECURITIES

The following table sets out the high and low trading prices and aggregate volume of trading of the Common Shares, as applicable, on all Canadian exchanges reported by the TSX from January 1, 2020 to March 10, 2021.

Price Range and Trading Volume

Period	High ($)	Low ($)	Volume
2020			
January	1.40	0.71	17,794,824
February	1.34	1.16	4,401,718
March	1.30	0.85	2,582,877
April	1.26	1.00	2,563,652
May	1.30	1.15	1,118,440
June	1.25	1.10	6,178,819
July	1.28	1.22	5,178,089
August	1.40	1.20	3,896,867
September	1.40	1.24	1,967,637
October	1.35	1.20	5,332,952
November	1.96	1.19	11,314,395
December	2.64	1.90	15,086,668
2021			
January	3.21	2.32	12,688,065
February	4.15	2.81	9,849,356
March (1 – 9)	4.06	3.72	3,428,805

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.

Impact of Pandemics

The COVID-19 pandemic may affect the Corporation's results, business, financial conditions or liquidity

Pandemics, epidemics or outbreaks of an infectious disease in Canada or worldwide, including COVID-19, Middle East Respiratory Syndrome, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu or any other similar illnesses could have an adverse impact on the Corporation's results, business, financial condition or liquidity.

On March 11, 2020, the World Health Organization declared the outbreak of a strain of novel coronavirus disease, COVID-19, a global pandemic. The COVID-19 pandemic has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. Unexpected developments in financial markets, regulatory environments, or consumer behaviour may also have adverse impacts on the Corporation's results, business, financial condition or liquidity, for a substantial period of time.

The Corporation's business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, be adversely impacted as a result of the pandemic.

The COVID-19 pandemic has also created additional operational risks for the Corporation, including the need to provide enhanced safety measures for its employees and customers; comply with rapidly changing regulatory guidance; address the risk of attempted fraudulent activity and cybersecurity threat behaviour; and protect the integrity and functionality of the Corporation's systems, networks, and data as employees work remotely. The Corporation is also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for a significant proportion of the Corporation's employees, including key executives, to be unable to work effectively, because of illness, quarantines, sheltering-in-place arrangements, government actions or other restrictions in connection with the pandemic.

The extent to which the COVID-19 pandemic continues to impact the Corporation's results, business, financial condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the development and widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the development and distribution of an effective vaccine also continues to raise uncertainty.

Weakness and Volatility in the Oil and Natural Gas Industry

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

Market events and conditions, including global excess oil and natural gas supply, the ongoing COVID-19 pandemic, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakened global relationships, conflict between the United States and Iran, isolationist and punitive trade policies, increased United States shale production, sovereign debt levels, world health emergencies (including the COVID-19 pandemic) and political upheavals in various countries including a growing anti-hydrocarbon sentiment, have caused significant weakness and volatility in commodity prices. See "*Risk Factors – Political Uncertainty*" and "*Risk Factors – The Impact of the Pandemic*". These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Industry Conditions – Royalties and Incentives", "Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*". In addition, the difficulties encountered by midstream proponents to obtain on a timely basis or continue to maintain the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

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

Hydraulic Fracturing

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

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

New Brunswick

Headwater would require hydraulic fracturing in connection with any future drilling and completion activities it conducts in New Brunswick. There has been public concern over the hydraulic fracturing process. Most of these concerns have raised questions regarding the drilling fluids used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations, the ability of such water to be recycled, and induced seismicity associated with fracturing. The U.S. and Canadian federal governments and certain U.S. state and Canadian provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in certain of the jurisdictions in which the Corporation operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct.

However, certain environmental and other groups have suggested that additional federal, provincial, territorial, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity particularly where in proximity to pre-existing faults.

It is anticipated that federal, provincial and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While the Corporation is unable to predict the impact of any potential regulations upon its business, the implementation of new laws, regulations or permitting regulations with respect to water usage or disposal, or hydraulic fracturing generally could increase the Corporation's costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact the Corporation's production and prospects, any of which may have a material adverse effect on the Corporation's business, financial condition and results of operations.

The New Brunswick Government announced on May 27, 2016 that it would indefinitely continue a moratorium on hydraulic fracturing. In November 2018, the Government of New Brunswick expressed its intention to allow natural gas development in the Sussex region, where Headwater's properties are located. On June 5, 2019, the Government of New Brunswick amended the *Prohibition Against Hydraulic Fracturing Regulation* to allow the Minister of Natural Resources and Energy Development to exempt certain operations in the Sussex region from the moratorium, though regulatory uncertainty remains regarding the availability of such exemptions.

Headwater believes that all new wells on its properties in New Brunswick require hydraulic fracture stimulation to be commercially productive. As a result of this announcement, Headwater has determined that it will not undertake any drilling activities in New Brunswick until the moratorium is lifted. Should the moratorium not be lifted, Headwater's ability to increase production beyond current levels in the McCully Field will be materially and adversely affected.

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

Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau and Red Deer. Since 2015, the AER has introduced seismic protocols for hydraulic fracturing operators in the Fox Creek, Red Deer and Brazeau areas (the "**Seismic Protocol Regions**") – initially in response to significant induced seismic activity in the Duvernay formation in Fox Creek in February 2015. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, leading to continued monitoring by the AER. The AER may extend seismic protocols to other areas of the province if necessary.

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

Prices, Markets and Marketing

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

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

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

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, shale oil production in the United States, OPEC+ actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, future borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

The Corporation has a various take or pay pipeline service agreements to deliver its heavy oil production from Marten Hills to market that expire in 2031. For details of the Corporation's transportation agreements in place as at December 31, 2020, see the Corporation's audited annual financial statements for the year ended December 31, 2020, which have been filed on SEDAR and may be viewed under the Corporation's profile at www.sedar.com.

In recent years, the price of natural gas in North America has been declining. However, the Corporation's natural gas production is sold to markets in New England, and more recently, the Maritimes, at prices referenced to AGT. The New England market, and recently the Maritimes market, have in recent years been characterized by excess demand during the winter season resulting in elevated prices for natural gas as compared to depressed prices in other areas of North America, and this excess demand is expected to continue until new pipeline infrastructure is available to increase the supply of natural gas into this market, especially given the end of offshore natural gas production in Atlantic Canada. While numerous projects are planned which could alleviate the supply constraints to the New England market, it is not known whether the required regulatory approvals will be received and, if the projects proceed, the timing of completion of these projects.

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

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

Exploration, Development and Production Risks

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

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

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

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

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

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

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

Market Price

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

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

Political Uncertainty

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

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During its tenure, the former American administration withdrew the United States from the Trans-Pacific Partnership and passed sweeping tax reform, which, among other things, significantly reduced U.S. corporate tax rates. This has affected the competitiveness of other jurisdictions, including Canada. The former U.S. administration also took action to reduce regulation, which affected relative competitiveness of other jurisdictions.

In addition, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**"), was ratified on July 1, 2020 and may impact the Corporation's business. See "*Industry Conditions - International Trade Agreements*".

The newly-inaugurated Biden administration in the U.S. has indicated that it will roll-back certain policies of the former administration, and has taken action to cancel TC Energy Corporation's ("**TC Energy**") Keystone X.L. pipeline permit. While it is unclear which other legislation or policies of the former Trump administration will be rolled-back and if such roll-backs will be a priority of the new administration in light of the ongoing COVID-19 pandemic, any future actions taken by the new U.S. administration could have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

In addition to the changing political landscape in the United States, the impact of the United Kingdom's exit from the European Union is slowly emerging and some impacts may not become apparent for some time. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

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

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

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development – particularly with respect to infrastructure projects. Protests, blockades, and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas and LNG*".

Gathering and Processing Facilities and Pipeline Systems

Lack of capacity and/or regulatory constraints on gathering and processing facilities and pipeline systems 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 and pipeline systems. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. 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 legal challenges to Cabinet's approval of the Trans Mountain Pipeline expansion were dismissed, and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Québec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In August 2019, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force resulting in changes to the federal regulation and associated environmental assessments of major projects. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

In January 2021, U.S. President Biden took steps to cancel the presidential permit that had allowed the Keystone X.L. Pipeline to operate across Canadian and American borders. It is unclear if challenges to the revocation of the permit will be successful and what the direct impact of the loss of permit will be on the Corporation.

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

Competition

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

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

Cost of New Technologies

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

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

Alternatives to and Changing Demand for Petroleum Products

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

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

Regulatory

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

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

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

Royalty Regimes

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

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

Environmental

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

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

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

Carbon Pricing Risk

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

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

Liability Management

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

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the Liability Management Rating Program (the "**AB LMR Program**") administered by the AER, are currently underway. In July 2020, the Government of Alberta announced that the AB LMR and associated programs will be replaced by the "Liability Management Framework" (the "**AB LMF**"). Other changes to the requirements of liability management programs, may result in significant increases to the Corporation's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in *Redwater Energy Corporation (Re)* ("**Redwater**) on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. As a result of the decision, the Government of Alberta implemented the *Liabilities Management Statutes and Amendment Act*, which places the financial burden of a defunct licensee's abandonment and reclamation obligations on the working interest partners of the defunct licensee and may order the AER's Orphan Fund to assume custody of wells or sites without a responsible owner to expedite the cleanup process.

In addition, the AB LMF Program may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

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

Chronic Climate Change Risks

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

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

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which has influenced investors' willingness to invest in the 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 recent years, climate change advocacy groups have attempted to bring legal action against various levels of government for climate-related harms.

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

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Corporation's ability to access its properties and cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to such assets.

Moreover, extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

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

Substantial Capital Requirements

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

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

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

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

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

Additional Funding Requirements

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

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

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

Issuance of Debt

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

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

Hedging

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

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

- production falls short of the hedged volumes or prices fall significantly lower than projected;

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

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

Availability and Cost of Material and Equipment

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

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

Title to and Right to Produce from Assets

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

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

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

Reserves Estimates

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

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

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

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

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

Geological complexities of the McCully Field make it difficult to predict the success of future exploration and development activities in the area. These complexities include the sporadic presence of over-pressured "perched" water in some portions of the reservoir, the presence of significant amounts of bitumen in some parts of the reservoir, as well as depositional and structural character of the reservoir.

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

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

Insurance

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

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

Non-Governmental Organizations

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

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

Reputational Risk Associated with the Corporation's Operations

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

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

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

Changing Investor Sentiment

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

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

Dilution

The Corporation may issue additional Common Shares, diluting current Shareholders

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

Management of Growth

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

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

Expiration of Licenses and Leases

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

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

Dividends

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

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

Litigation

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

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

Co-Existence with Mining Operations

The Corporation's activities may be affected by historical potash mining operations

Nutrien has historically conducted potash mining operations pursuant to a lease granted by the Government of New Brunswick that overlays a substantial portion of the McCully Field. In 2018, Nutrien permanently closed its potash facility after putting the operation on care and maintenance in early 2016. Applicable legislation requires that oil and gas activities not interfere with mining operations and that mining activities not interfere with oil and gas operations. The Corporation has to date succeeded in conducting its business activities in a manner that does not interfere with such mining operations. For example, several of the wells previously drilled by the Corporation have been drilled directionally to access natural gas beneath the potash mine. Notwithstanding the closure of the mining operations by Nutrien, there can be no assurance that the Corporation's future exploration and development activities will not be adversely affected as a result of the historical potash mining operations, including the possibility that a portion of the McCully Field may not be accessible for natural gas development.

Indigenous Claims

Indigenous claims may affect the Corporation

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

Breach of Confidentiality

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

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

Income Taxes

Taxation authorities may reassess the Corporation's tax returns

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

Income tax laws relating to the 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.

Third Party Credit Risk

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

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

Conflicts of Interest

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

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

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel may negatively impact 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. The Corporation does not have any key personnel insurance in effect. Contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If the Corporation is unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

Information Technology Systems and Cyber-Security

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

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

Further, the Corporation is subject to a variety of information technology and system risks as a part of its 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 business activities or the Corporation's competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information, or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Corporation's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware. The ongoing COVID-19 pandemic has increased the prevalence of cyberattacks, as increased malicious activities are creating more threats for cyberattacks including COVID-19 phishing emails, malware-embedded mobile apps that purport to track infection rates, and targeting of vulnerabilities in remote access platforms as many companies continue to operate with work from home arrangements.

Cyber phishing activities are a serious problem that may damage the Corporation's information technology infrastructure. The Corporation applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Corporation's performance and earnings, as well as its reputation, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Social Media

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

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Corporation's systems and obtain confidential information. The Corporation periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, 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.

Forward-Looking Information

Forward-looking information may prove inaccurate

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

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

Expansion into New Activities

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

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

Project Risks

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

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

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

Seasonality

Oil and natural gas operations are subject to seasonal weather conditions and, if applicable to the Corporation's operations in the future, the Corporation may experience significant operational delays as a result

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

Waterflood

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

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

INDUSTRY CONDITIONS

Companies operating in the Canadian oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government as well as with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation's assets and operations are regulated by administrative agencies that derive their authority from 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 and construction of related infrastructure; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, including by reducing emissions; (vi) 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, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions.

The discussion below outlines some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Canada, specifically in the provinces of Alberta and New Brunswick, where the Corporation's assets are primarily located. Although the Corporation also has undeveloped land in the province of Saskatchewan, it does not currently have any significant operations in either province. While these matters do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such matters carefully.

Pricing and Marketing in Canada

Crude Oil

Oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Since early 2020, worldwide oversupply of oil, a lack of available storage capacity and decreased demand due to COVID-19 have had a significant impact on the price of oil. In an effort to stabilize global oil markets, the Organization of the Petroleum Exporting Countries and a number of other oil producing countries announced an agreement to cut oil production by approximately 10 million bbls/d in April 2020. This agreement contributed to rebalancing global oil markets. However, economic recovery has slowed in some respects due to a resurgence of COVID-19 and newly emerging virus variants in major economies.

Natural Gas

Negotiations between buyers and sellers determine the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale.

Natural Gas Liquids ("NGLs")

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms of sale.

Exports from Canada

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "**CERA**"). Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Corporation does not directly enter into contracts to export its production outside of Canada.

One major constraint to the export of oil, natural gas and NGLs is the deficit of transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation and export projects are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due, in part, 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 over the last several years.

Transportation Constraints and Market Access

Under the Canadian Constitution, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines also require approvals from several levels of government in the United States.

Producers negotiate with pipeline operators to transport their products to market on a firm or interruptible basis depending on the specific pipeline and the specific substance. 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 and the price received.

Oil Pipelines

Specific Pipeline Updates

The Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, has faced significant delays due to permitting difficulties in the United States. However, Minnesota regulators approved the final required permit for the project in November 2020. Certain segments of the Line 3 Replacement in North Dakota and Wisconsin are currently in operation and the Canadian portion of the replaced pipeline began commercial operation in December 2019. Construction of the Line 3 Replacement in Minnesota began in early December 2020; Enbridge expects the line to be in service in the fourth quarter of 2021.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019 and it is expected to be in-service in December 2022.

On March 31, 2020, TC Energy announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility. While construction on the Keystone XL Pipeline started in April 2020, the project remains subject to legal and regulatory barriers in the United States, including the cancellation of a presidential permit on January 20, 2021 that permits the Keystone XL Pipeline to operate across the international border.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, potentially forcing the lines comprising this segment of the pipeline system to be shut down by May 2021. Enbridge filed a federal complaint in late November 2020 in the Unites States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards.

Marine Tankers

The *Oil Tanker Moratorium Act*, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Crude Oil and Bitumen by Rail

Following two train derailments that led to fires and oil spills in Saskatchewan, the federal government announced in February 2020 that trains hauling more than 20 cars carrying dangerous goods, including oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in April 2020 and replaced

in November 2020. The speed limits and other requirements established in Order MO 20-10 will remain in place until permanent rule changes are approved.

Enbridge Open Season

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

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. The regulatory hearing process is currently underway and a final decision from the CER is not expected until mid-2021. If Enbridge receives CER approval, it intends to hold the open season by the end of 2021.

Natural Gas and LNG

Natural gas prices in Western Canada have 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 infrastructure 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 relative to other markets.

Required repairs or upgrades to existing pipeline systems in western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline system (the "**NGTL System**") to prioritize deliveries into storage (the "**Temporary Service Protocol**"). The change stabilized supply and pricing, particularly during periods of maintenance on the system, but, in February 2021, the CER refused a request to extend the Temporary Service Protocol. However, in October 2020, TC Energy received federal approval to expand the NGTL System and the expanded NGTL System is expected to be fully operational by April 2022.

The majority of the Corporation's current natural gas production is currently concentrated in New Brunswick and the Corporation projects an excess of available capacity on the Canadian portion of the Maritimes and Northeast Pipeline ("**M&NP**") for the foreseeable future. The Corporation produces natural gas from its operations in the McCully Field near Sussex, New Brunswick, and sells all of its natural gas in the Maritimes and in New England, pursuant to a long-term agreement with Repsol, which includes transportation service on the segment of the M&NP that is located in the United States. The Corporation does not foresee any restricted access to American markets for its natural gas production from the McCully Field for the foreseeable future.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In late 2019, TC Energy announced that it would sell a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction closed in May 2020. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding.

In addition to LNG Canada and the CGL Pipeline projects, the following is an update on various other LNG Projects that have been proposed in Canada:

- 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. However, both partners are looking to sell some or all of their interest in the project.

- Woodfibre LNG Limited, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. has proposed to build the Woodfibre LNG Project, a small-scale LNG processing and export facility near Squamish, British Columbia. The British Columbia Oil and Gas Commission approved a project permit for the Woodfibre LNG Project in July 2019 and a formal approval of the project is expected in the third quarter of 2021, with construction beginning shortly thereafter.

- GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently working its way through a 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 in Québec. The Énergie Saguenay Project is currently slated for completion in 2026.

- Pieridae Energy Ltd.'s ("**Pieridae**") proposed Goldboro LNG project, located in Nova Scotia, 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, but Pieridae has delayed its final investment decision until mid-2021.

- Finally, Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, 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**").

Curtailment

In December 2018, the Government of Alberta announced that it would mandate a short-term and temporary curtailment of provincial crude oil and bitumen production. Curtailment first took effect on January 1, 2019. As contemplated in the *Curtailment Rules*, the Government of Alberta, on a monthly basis, required oil and bitumen producers producing more than 20,000 bbls/d to limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators that are subject to curtailment orders.

As of December 2020, monthly oil production limits are no longer in effect. However, the *Curtailment Rules*, which were set to be repealed on December 31, 2020, have been extended such that the Government of Alberta retains the ability to impose future production limits if needed.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the USMCA, which replaced the former NAFTA on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on Canada's oil and gas industry at large, including the Corporation's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia and Europe.

Land Tenure

Mineral rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. In New Brunswick, the Crown owns all mineral rights to crude oil and natural gas. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (collectively, "**leases**") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

In response to COVID-19, the governments of Alberta announced measures to extend or continue Crown leases that may have otherwise expired in the months following the implementation of pandemic response measures.

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

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop oil and natural gas reserves.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada manages subsurface and surface leases in consultation with 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 Indigenous reserve lands were governed by the *Indian Oil and Gas Act* (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 and further regulations are currently being developed. The Corporation does not have operations on Indigenous reserve lands.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage. Similar rules apply to facility and pipeline operators.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable.

Producers and working interest owners of oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

Occasionally, the provincial governments in Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

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

Alberta

Crown royalties

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

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

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

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable

Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

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

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

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner.

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

New Brunswick

The Crown owns all crude oil and natural gas resources in New Brunswick. Though New Brunswick currently has no commercial crude oil production, the province calculates royalties on oil by assigning a sliding scale percentage to monthly production. The royalty percentage assigned to oil production ranges from 5% at production volumes of 1-49m3, to 12% at volumes equal to or greater than 720 m3.

Natural gas royalties in New Brunswick consist of a basic royalty component and an economic rent royalty component. Unlike other provinces, New Brunswick does not charge royalties on a per well basis, applying the royalty to a producer's aggregate production. The basic royalty is the greater of 4% of the product of the wellhead price of produced natural gas and all units of natural gas produced by the licensee or lessee in the province in that month, and 2% of a licensee's or lessee's monthly gross revenue from natural gas sales at all of its wells. The wellhead price is the selling price of natural gas minus transportation costs and a gas processing allowance. The economic rent royalty is 25% of the cumulative gross revenue from all of a licensee's or lessee's natural gas operations in New Brunswick, minus the sum of all capital expenditures and operating costs associated with those operations. Thus, the economic rent royalty will not come into effect until the licensee or lessee recovers all eligible costs and begins to make a profit.

The royalty on all by-products obtained in the production of oil and natural gas, including sulphur, helium, natural gas liquids and condensates is 10% of the greater of the actual selling price of those by-products, or their fair market value at the time and place of production.

Regulatory Authorities and Environmental Regulation

General

The Canadian oil and gas industry is 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 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, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

On August 28, 2019, the *Impact Assessment Act* (the "**IAA**") replaced the *Canadian Environmental Assessment Act, 2012*.

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

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

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA, but this matter remains before the courts.

Alberta

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

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

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

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

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau. The Corporation does not have operations in Fox Creek, Red Deer and Brazeau.

New Brunswick

Oil and natural gas exploration in New Brunswick is regulated by the Department of Environment and Local Government, and the Department of Natural Resources and Energy Development. Environmental protection is legislated in the *Clean Air Act*, *Clean Water Act*, *Clean Environment Act*, and the associated regulations.

On February 15, 2013, New Brunswick released the "Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick", a document detailing the province's rules for the oil and gas industry. The document addresses several important areas of industry management including concerns associated with geophysical (seismic) testing, the escape of contaminants from the wellbore and well pad, greenhouse gas emissions, public safety and emergency planning, protecting communities and the environment, and reducing financial risk and protecting landowner rights.

In 2015, New Brunswick implemented the *Prohibition Against Hydraulic Fracturing Regulation*, banning all hydraulic fracturing in the province. The New Brunswick Government announced on May 27, 2016 that it would indefinitely continue a moratorium on hydraulic fracturing. In November 2018, the Government of New Brunswick expressed its intention to allow natural gas development in the Sussex region, where Headwater's properties are located. On June 5, 2019, the Government of New Brunswick amended the *Prohibition Against Hydraulic Fracturing Regulation* to allow the Minister of Natural Resources and Energy Development to exempt certain operations in the Sussex region from the moratorium, though regulatory uncertainty remains regarding the availability of such exemptions. At the present time, no exemption has been granted to allow hydraulic fracturing on the Corporation's lands in the McCully Field in New Brunswick.

See "*Risk Factors – Hydraulic Fracturing*".

Liability Management Rating Programs

Alberta

The AER administers a Liability Management Rating Program (the "**AB LMR Program**"), which is currently undergoing changes, including a name change to the "Liability Management Framework" (the "**AB LMF**"); however, specific details concerning this new program remain forthcoming. 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 Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LFP**"), and the Licensee Liability Rating Program (the "**AB LLR Program**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the licensee, must reduce its liabilities or provide the AER with a security deposit. Failure to do so 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.

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

In response to the increase in orphaned oil and gas sites and the environmental risks associated therewith, the AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that they can meet their abandonment and reclamation obligations, such as by posting security or reducing their existing obligations.

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

Additionally, the Government of Alberta announced in July 2020 that the AB LMF will replace the AB LMR Program and its constituent programs. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LMR Program and establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of oil and gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

The Government of Alberta followed the announcement of the AB LMF with amendments to the *Oil and Gas Conservation Rules* and the *Pipeline Rules* in late 2020. The changes to these rules fall into three principal categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the

AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

The AER has published a draft of an amended Directive 067 to implement some of these changes (the "**Draft Directive**"). The changes introduced by the Draft Directive include building on the AER's corporate and financial disclosure requirements for parties who wish to acquire, hold or transfer licences in Alberta, and broadening the AER's discretion to withhold or revoke licensees' privileges if they are assessed as posing an "unreasonable risk". The feedback that the AER receives will be considered in the determination of the final revised Directive 067, and the rollout of the AB LMF may require changes to other Directives as well. As a result, the Corporation's ongoing and future transactions may be affected in this period of transition, resulting in processing delays for licence transfers and regulatory uncertainty as the criteria and requirements for licensees are subject to change.

To address abandonment and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. Beginning in 2015, for example, the AER oversaw the Inactive Well Compliance Program, a five-year program intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work of inactive assets.

New Brunswick

Unlike other oil and natural gas producing provinces in Canada, New Brunswick does not administer a liability management or orphan well program. Instead, producers seeking to obtain licences or leases for exploration or production activities must provide a security deposit intended to backstop the licensee's ability to properly conduct any abandonment or reclamation activities. For well licences, applicants must also provide proof of and maintain liability insurance in the amount of $10,000,000. In addition, a licensee may only transfer its licence with the written approval of the Minister of Natural Resources and Energy Development.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the Site Rehabilitation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. Decisions about a prospective carbon market and emissions cuts have been delayed until the next climate conference, which is scheduled to take place in November 2021.

The Government of Canada has pledged to cut its emissions by 30% from 2005 levels by 2030, but indicated in its recent Speech from the Throne (also referred to as the "**Throne Speech**"; discussed in greater detail below) that it may implement policy changes to exceed this target.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of \$20/tonne of CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. This ensures that there is a uniform price on emissions across the country. Under current federal plans, this price will escalate by \$10 per year until it reaches a price of \$50/tonne of CO2e in 2022. On December 11, 2020, however, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by \$15 per year until it reaches \$170/tonne of CO2e in 2030. Starting April 1, 2021, the minimum price permissible under the GGPPA is \$40/tonne of CO2e.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In the Saskatchewan and Ontario references, the appellate Courts found the GGPPA to be constitutional; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments have been appealed to the Supreme Court of Canada. The hearing took place in September 2020, but the Court has not yet released its decision.

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 sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure 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. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced a \$750 million Emissions Reduction Fund intended to support pollution reduction initiatives, including methane. Funds disbursed through this program will primarily take the form of repayable contributions to onshore and offshore oil and gas firms.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the September 23, 2020 Throne Speech, the federal government has indicated that it intends to make a number of investments that will help it achieve net-zero emissions by 2050, including investments intended to: (i) improve transit options; (ii) make zero-emissions vehicles more affordable; (iii) expand electric vehicle charging infrastructure across the country; (iv) launch a fund that will help attract investments in the development of zero-emissions technology, including a corporate tax cut of 50% for companies participating in this initiative; (v) develop a Clean Power Fund that will, in part, help regions transition to cleaner sources of power generation; and (vi) support continued investment in the development and implementation of renewable and clean energy technologies. Specific program details have not yet been announced.

On November 19, 2020, the federal government introduced the *Canadian Net-Zero Emissions Accountability Act* in Parliament. If passed, this Act will bind the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making.

Alberta

In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed.

In June 2019, the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta will increase from $30/tonne of CO2e to $40/tonne of CO2e on April 1, 2021. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction* ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous *Carbon Competitiveness Incentives Regulation*.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. 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 aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* 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 the updated 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 Directives will support Alberta in achieving its 2025 goal. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

New Brunswick

In December 2016, New Brunswick released a climate change action plan, "Transitioning to a Low-carbon Economy" (the "**Transition Plan**"). Pursuant to this plan, the province announced that it intended to procure electricity from cleaner generation sources, including renewable sources and the use of renewable technologies, regulate GHG emissions from large industrial facilities, and reduce overall emissions in a manner that reflects the realities of the New Brunswick economy. Other initiatives under the plan include the phasing out of coal as a source of electricity, investing in new pollution-reduction technology, and increasing progress reporting and oversight by government committees.

The *Electricity Act* requires that 40% of in-province electricity sales in New Brunswick is electricity from renewable sales.

In March, 2018, New Brunswick enacted the *Climate Change Act*, which became effective on January 1, 2016. Under the Climate Change Act, New Brunswick committed to lowering its GHG emissions to 14.8 megatonnes by 2020, 10.7 megatonnes by 2030, and 5 megatonnes by 2050, targets that were originally established in the Transition Plan. New Brunswick has already met its 2020 emissions reduction goal. The *Climate Change Act* also established a Climate Change Fund. The legislation did not immediately introduce a carbon pricing system or fuel charge levy. As a result, the output-based emissions trading program for large emitters and federal fuel charge levy applied in the province as of January 1, 2019 and April 1, 2019, respectively. However, the legislation did allow the New Brunswick Minister of Environment and Local Government to enter into agreements with the federal government regarding carbon pricing and funds generated from it.

In December, 2019, the federal government announced that it had accepted New Brunswick's proposed fuel charge program. On March 13, 2020, New Brunswick passed two Acts amending the *Gasoline and Motive Fuel Tax Act* (the "**GMTA**") to reflect the terms proposed to the federal government. These amendments received royal assent on March 17, 2020, and the New Brunswick fuel charge took effect on April 1, 2020. Under the GMTA, a charge equivalent to the federal fuel charge applies to the consumption of "carbon emitting products" in the province; however, the provincial government has lowered its excise tax on gasoline such that the net effect of the charge is a $0.02 per litre increase. All revenues from this charge will be invested in climate change initiatives. In addition, the provincial government rebates the fuel charge collected on natural gas to Liberty Utilities, the provincial distributor of natural gas for utilities purposes, which amount is then credited to customers.

On the same day that the amendments to the GMTA received royal assent, an *Act to Amend the Climate Change Act* also received royal assent. These amendments establish the framework for a provincially administered output-based pricing mechanism for industrial emitters. Under this program—deemed to have come into force on January 1, 2019—industrial facilities that emit more than 50,000 tonnes of CO2e per year will be subject to a mandatory emissions reduction requirements and charges for non-compliance. Facilities that emit more than 10,000 tonnes of CO2e but less than 50,000 CO2e may opt-in to the program. Facilities that fail to meet their targets may purchase credits to offset their surplus emissions and facilities that exceed their reductions targets can earn performance credits that they can then sell to other facilities. In September 2020, the Government of Canada notified the Government of New Brunswick that its output-based pricing system for industrial emitters satisfied federal standards; however, the transition timeline from the federal program to the provincial program remains under discussion.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Canadian oil and gas industry. In addition, Canada is a signatory to the *United Nations Declaration of the Rights of Indigenous Peoples* ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In December 2020, the federal government introduced *Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act* ("**Bill C-15**"). Similar to British Columbia's DRIPA, the intention of Bill C-15, if passed, is to establish a process whereby the Government of Canada will take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and Bill C-15 are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines.

LEGAL PROCEEDINGS

Headwater is not a party to any legal proceeding nor was it a party to any legal proceeding during the 2020 financial year, nor is Headwater aware of any contemplated legal proceeding involving Headwater, its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of Headwater.

During the year ended December 31, 2020 and as at the date hereof, as applicable, there were and are: (i) no penalties or sanctions imposed against Headwater or 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 Headwater that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements Headwater entered into before a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described below or elsewhere herein, to the knowledge of management of the Corporation there were no material interests, direct or indirect, of directors or executive officers of the Corporation, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than ten percent (10%) of the outstanding voting securities of the Corporation, or any other Informed Person (as defined in NI 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or would materially affect the Corporation or any of its subsidiaries.

Cenovus, through CMHP, currently holds 50,000,000 Common Shares representing 25.6% of the currently issued and outstanding Common Shares. Cenovus, through CMHP, also currently holds 15,000,000 Cenovus Warrants. If CMHP exercised all of the Cenovus Warrants, Cenovus, through CMHP, would hold 65,000,000 Common Shares representing 30.9% of the issued and outstanding Common Shares.

On November 8, 2020, the Corporation entered into the purchase and sale agreement with Cenovus and CMHP in respect of the Cenovus Transaction. On closing of the Cenovus Transaction the Corporation entered into a number of other agreements with CMHP including the Investor Agreement, the Development Agreement and the Royalty Agreement. See "*General Development of the Business – Year 2020 – Transaction with Cenovus*" and "*Material Contracts*" for more information about the Cenovus Transaction and the related agreements.

At the time the Corporation, Cenovus and CMHP entered into the purchase and sale agreement with respect to the Cenovus Transaction, neither Cenovus nor CMHP held any securities of Headwater and neither Cenovus nor CMHP had any representatives or nominees serving on the Board.

AUDIT COMMITTEE INFORMATION

National Instrument 52-110 – *Audit Committees* ("**NI 52-110**") requires the Corporation, as a non-venture issuer, to disclose annually in its Annual Information Form certain information concerning the constitution of its audit committee and its relationship with its independent auditor in accordance with Form 52-110F1.

Audit Committee Mandate and Terms of Reference

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

Composition of the Audit Committee

The members of the Audit Committee are Chandra Henry (Chair), Kevin Olson and Kam Sandhar are considered independent in accordance with NI 52-110. All of the members of the Audit Committee are considered financially literate. Each of the members of the Audit Committee has identified themselves as financial experts due to their relevant education and experience. The following is a description of the education and experience of each member of the Audit Committee.

Name and Place of Residence	Independent	Financially Literate	Relevant Education and Experience
Chandra Henry Alberta, Canada	Yes	Yes	Ms. Henry is currently Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc. and is a director of Bonavista Energy Corporation. Ms. Henry was formerly a director of Pengrowth Energy Corporation. Prior to her role with Longbow, Ms. Henry was the Chief Financial Officer of FirstEnergy Capital Corp. Ms. Henry has a Bachelor of Commerce degree from the University of Calgary and has earned the Chartered Professional Accountant (CPA, CA), Chartered Financial Analyst (CFA) and Institute of Corporate Directors (ICD.D) designations.
Kevin Olson Alberta, Canada	Yes	Yes	Mr. Olson has over 25 years of industry experience and is currently President of Camber Capital Corp. Mr. Olson is a former board member of Baytex, Raging River, Wild Stream, Wild River and Prairie Schooner Petroleum Ltd. Mr. Olson has managed four early stage energy funds and served as a director of a variety of exploration and production companies and petroleum services companies. Formerly Mr. Olson was Vice-President, Corporate Finance at FirstEnergy Capital Corp. and Vice-President, Corporate Development for Northrock Resources Ltd. Mr. Olson holds a Bachelor of Commerce degree (Distinction) majoring in finance and accounting from the University of Calgary.
Kam Sandhar Alberta, Canada	Yes	Yes	Mr. Sandhar is currently the Executive Vice-President, Strategy and Corporate Development of Cenovus. Mr. Sandhar has nearly 20 years of experience in the oil and gas industry and has extensive expertise in strategy, business development, finance and investor relations. Prior to joining Cenovus in 2013, Mr. Sandhar spent nine years at Peters & Co. Limited where he served as a Principal and oil and gas analyst, covering a wide array of Canadian, U.S. and international oil and gas companies. Mr. Sandhar started his career at Deloitte LLP where he focused on oil and gas audit and taxation. Mr. Sandhar is a Chartered Professional Accountant and a member of the Chartered Professional Accountants of Alberta. He holds a Bachelor of Commerce degree from the University of Calgary.

Pre-Approval of Policies and Procedures

The Audit Committee has adopted a policy to review and pre-approve any non-audit services to be provided to the Corporation by the external auditors and consider the impact on the independence of such auditors. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

External Auditor Service Fees

The Audit Committee has reviewed the nature and amount of non-audit services provided by KPMG LLP, Chartered Professional Accountants to the Corporation to ensure auditor independence. Fees paid to KPMG LLP and to the

Corporation's former auditor PricewaterhouseCoopers LLP for audit and non-audit services in the last fiscal year are outlined in the following table:

Nature of Services	Fees Paid for Period Ended December 31, 2020	Fees Paid for Period Ended December 31, 2019
Audit Fees(1)		
KPMG LLP	$64,200	$nil
PricewaterhouseCoopers LLP	$106,211	$130,300
Audit-Related Fees(2)		
KPMG LLP	$nil	$nil
PricewaterhouseCoopers LLP	$nil	$nil
Tax Fees(3)		
KPMG LLP	$3,567	$nil
PricewaterhouseCoopers LLP	$nil	$4,650
All Other Fees(4)		
KPMG LLP	$nil	$nil
PricewaterhouseCoopers LLP	$19,980	$nil
Total		
KPMG LLP	**$67,767**	**$nil**
PricewaterhouseCoopers LLP	**$126,191**	**$134,950**

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of the Corporation's financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance (KPMG LLP $3,567/PricewaterhouseCoopers LLP $nil 2020/ KPMG LLP $nil/PricewaterhouseCoopers LLP $4,650 2019), tax planning (KPMG LLP $nil/PricewaterhouseCoopers LLP $nil 2020/ KPMG LLP $nil/PricewaterhouseCoopers LLP $nil 2019) and tax advice (KPMG LLP $nil/PricewaterhouseCoopers LLP $nil 2020/ KPMG LLP $nil/PricewaterhouseCoopers LLP $nil 2019). Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.

(4) "All Other Fees" include all other non-audit services.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contract entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year which is still in effect is the Investor Agreement.

Pursuant to the Investor Agreement the Corporation granted CMHP the right to appoint two (2) nominees to the Board if CMHP, together with its affiliates, owns twenty percent (20%) or more of the outstanding Common Shares, or one (1) nominee, if CMHP, together with its affiliates, owns ten percent (10%) or more but less than twenty percent (20%) of the outstanding Common Shares. The Investor Agreement also provides CMHP with a right to participate in future offerings of Common Shares or securities of the Corporation which are convertible, exchangeable or exercisable into Common Shares, subject to CMHP owning or controlling, directly or indirectly, at least twenty percent (20%) of the issued and outstanding Common Shares at the time of such offering (the "**Participation Rights**"). The Participation Rights allow CMHP to subscribe for the percentage of Common Shares or other securities being offered in the offering, which is equal to or less than CMHP's then ownership of the issued and outstanding Common Shares (expressed as a percentage).

During the term of Investor Agreement, CMHP is required to vote for or otherwise abstain from voting in respect of any management proposal set forth in the management forms of proxy prepared in respect of any meeting of Shareholders. In addition, CMHP agreed to certain standstill provisions during the term of the Investor Agreement. The Investor Agreement terminates at the earlier of (i) the date that CMHP and its affiliates cease to hold 10% or more of the issued and outstanding Common Shares; or (ii) the date on which CMHP delivers a notice of its intent to terminate the Investor Agreement along with executed resignations from each of CMHP's nominees on the Board. A copy of the Investor Agreement is available on SEDAR at www.sedar.com.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made by Headwater under NI 51-102 during, or related to, Headwater's most recently completed financial year other than GLJ, the independent engineering evaluator for Headwater, and KPMG LLP, the auditors for Headwater, and PricewaterhouseCoopers LLP the former auditors for Headwater and the auditors of the operating statements included in the business acquisition report filed by Headwater in relation to the Cenovus Transaction.

None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any of Headwater's securities or other property of Headwater or of Headwater's associates or affiliates either at the time they prepared the statement, report or valuation prepared by them, at any time thereafter or to be received by them. Both KPMG LLP and PricewaterhouseCoopers LLP have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Headwater, or of any of our associates or affiliates.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans will be contained in the Corporation's management information circular for the Corporation's next annual meeting of securityholders that involves the election of directors. Additional financial information is contained in the Corporation's financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

SCHEDULE "A"

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Headwater Exploration Inc. (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.

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

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

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

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

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

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

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

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

(c) the content and filing of this report.

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

DATED as of this 10th day of March, 2021.

(signed) *"Neil Roszell"*
Neil Roszell
Chief Executive Officer and Chairman

(signed) *"Jason Jaskela"*
Jason Jaskela
President and Chief Operating Officer

(signed) *"Kevin Olson"*
Kevin Olson
Director

(signed) *"David Pearce"*
David Pearce
Director

SCHEDULE "B"

FORM 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the board of directors of Headwater Exploration Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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, 2020, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income tax, 10% discount rate)			
			Audited	**Evaluated**	**Reviewed**	**Total**
			M$	M$	M$	M$
GLJ Ltd.	December 31, 2020	Canada	nil	182,337	nil	182,337

6. In our opinion, the reserves data 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:

GLJ PETROLEUM CONSULTANTS LTD., Calgary, Alberta, dated February 22, 2021.

Per: signed *"Chad Lemke"*
Chad Lemke, P.Eng.
Executive Vice President & COO

SCHEDULE "C"

HEADWATER EXPLORATION INC.
AUDIT COMMITTEE MANDATE

1. **Establishment Audit Committee:** The board of directors (the "**Board**") of Headwater Exploration Inc. (the "**Corporation**") hereby establishes a committee to be called the Audit Committee (the "**Committee**").

2. **Membership:** The Committee shall be comprised of at least three (3) directors or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 – *Audit Committees* ("**NI 52-110**")) unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon. All of the members of the Committee must be "financially literate" unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110. For the purposes of this Mandate, "financially literate" has the meaning ascribed thereto in NI 52-110 and means that the member has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements.

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

3. **Role and Objective:** The Committee shall, in addition to any other duties and responsibilities specifically delegated to it by the Board, generally assume responsibility for oversight of the following:

   (a) nature and scope of the annual audit;

   (b) the oversight of management's reporting on internal accounting standards and practices;

   (c) the review of financial information, accounting systems and procedures;

   (d) financial reporting and financial statements,

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

   The primary objectives of the Committee are as follows:

   (a) to assist the Board in meeting its responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

   (b) to provide better communication between directors and external auditors;

   (c) to ensure the external auditor's independence;

   (d) to increase the credibility and objectivity of financial reports; and

   (e) to strengthen the role of the independent directors of the Corporation by facilitating in-depth discussions between directors of the Committee, management of the Corporation and external auditors.

4. **Mandate and Responsibilities of Committee:** The Committee will have the authority and responsibility to:

(a) oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting;

(b) satisfy itself on behalf of the Board with respect to the Corporation's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements;

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

  (i) reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

  (ii) reviewing significant accruals, reserves, estimates (such as the ceiling test calculation) and judgments made by management in preparation of financial statements and the appropriateness of such accruals, reserves, estimates and judgments;

  (iii) reviewing accounting treatment of unusual or non-recurring transactions;

  (iv) ascertaining compliance with covenants under loan agreements;

  (v) reviewing disclosure requirements for commitments and contingencies;

  (vi) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

  (vii) reviewing unresolved differences between management and the external auditors; and

  (viii) obtain explanations of significant variances with comparative reporting periods.

(d) review the financial statements, MD&A and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval; the Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of other financial information and must periodically assess the adequacy of those procedures;

(e) with respect to the appointment of external auditors by the Board:

  (i) recommend to the Board the external auditors to be nominated;

  (ii) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;

  (iii) on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;

  (iv) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;

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

(vi) review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries;

(f) review with external auditors (and internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses;

(g) review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance);

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

(i) establish a procedure for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters; and

(j) review and approve the Corporation's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

5. **Meeting Administrative Matters:** The following general provisions shall have application to the Committee:

(a) At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.

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

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

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

(e) The Committee will meet with the external auditor in camera at least once per quarter (in connection with the preparation of the annual and interim financial statements) and at such other times as the external auditor and the Committee consider appropriate.

(f) Agendas will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

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

(h) Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee as requested.

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

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

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

(l) Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board or the Lead Independent Director by the Committee Chair.

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