ANNUAL INFORMATION FORM
DATED FEBRUARY 24, 2021

WHITECAP RESOURCES INC

www.wcap.ca

WHO WE ARE

We are a Calgary-based public company focused on the acquisition, development and production of oil and natural gas assets in Western Canada. The primary areas of focus of our development programs are in northwest Alberta and British Columbia, west central Alberta, west central Saskatchewan, southwest Saskatchewan and southeast Saskatchewan. Our business plan is to deliver profitable growth to our Shareholders over the long term under varying business conditions. We are focused on providing sustainable monthly dividends and per share growth through a combination of accretive oil-based acquisitions and organic growth on existing and acquired assets.

WHAT'S INSIDE

GLOSSARY OF TERMS

Entities and Transactions

Board of Directors or **Board** means our board of directors.

Shareholders means holders of our Common Shares.

NAL means NAL Resources Limited.

NAL Transaction means the strategic combination of us with NAL's western Canadian operated oil and gas business which was completed on January 4, 2021 and pursuant to which we issued approximately 58.3 million Common Shares to the NAL Vendor.

NAL Vendor means The Manufacturers Life Insurance Company.

Spitfire means Spitfire Energy Inc.

TORC means TORC Oil & Gas Ltd.

TORC Transaction means the strategic combination of us with TORC which was completed on February 24, 2021 and pursuant to which we issued approximately 129.8 million Common Shares to the former shareholders of TORC.

Whitecap, **we**, **us, our** or the **Corporation** means Whitecap Resources Inc., and where the context requires, also means our controlled entities on a consolidated basis.

Independent Engineering

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

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

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

McDaniel Report means the report prepared by McDaniel dated February 11, 2021, evaluating the crude oil, natural gas, NGLs and sulphur reserves attributable to all of our oil and natural gas assets as at December 31, 2020.

McDaniel NAL Report means the report prepared by McDaniel for Whitecap dated February 11, 2021, evaluating the crude oil, natural gas, NGLs and sulphur reserves attributable to all of NAL's oil and natural gas assets as at December 31, 2020.

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

Sproule means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

Sproule Report means the report prepared by Sproule for TORC dated February 22, 2021, evaluating the crude oil, natural gas, NGLs and sulphur reserves attributable to all of TORC's oil and natural gas assets as at December 31, 2020.

Share and Loan Capital

Common Shares means our common shares, as presently constituted.

Credit Facility means collectively our revolving syndicated facility and revolving operating facility with a syndicate of lenders, all as more particularly described under the heading "*Description of our Capital Structure – Credit Facility*".

Senior Secured Notes means our senior secured notes as more particularly described under the heading "*Description of our Capital Structure – Senior Secured Notes*".

ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	Mcf/d	thousand cubic feet per day
Bbls/d	barrels per day	MMbtu	million British Thermal Units
Mbbls	thousand barrels	MMcf	million cubic feet
NGLs	natural gas liquids		

Other	
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars
$Cdn	Canadian dollars
$US	United States of America dollars

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

OIL AND GAS ADVISORIES

Barrel of Oil Equivalency

The term "Boe" may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet of natural gas to barrels of oil (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 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value**.

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

NOTICE TO READER

Special Note Regarding Forward-Looking Statements

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "approximately", "may", "believe", "measure", "stability", "depends", "expects", "will", "intends", "should", "could", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "objective", "ongoing", "continues", "sustainability" or similar words or the negative thereof or other comparable terminology. In addition, there are forward-looking statements in this Annual Information Form under the headings: "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our focus, business plan and strategy; "*General Description of Our Business – Cyclical and Seasonal Impact of Industry*" as to the impact of our price risk management programs; "*General Description of Our Business – Environmental Policies*" with respect to our competitive position within the oil and gas industry not being affected by changes in applicable legislation, the focus of our environmental management program and operating guidelines and expectations regarding abandonment and reclamation costs; "*General Development of Our Business – Renegotiation or Termination of Contracts"* as to our expectations relating to the effect of the renegotiation or termination of our contracts or subcontracts in the remainder of 2020; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Reserves Data (Forecast Prices and Costs)*" as to our reserves and future net revenue from our reserves, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, other than the factors disclosed under this heading, our expectation that no other significant factors or significant uncertainties will affect any particular components of our reserves data, abandonment and reclamation obligations, future developments costs, our plans to fund future development costs and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our exploration and development focus, plans and opportunities, anticipated land expiries, anticipation that no significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves, hedging and marketing policies, tax horizon, anticipated drilling activity for 2020 and future production; "*Updates to Reserves Data – NAL Transaction*" as to NAL's reserves and future net revenue from NAL's reserves and pricing; "*Updates to Reserves Data – TORC Transaction*" as to TORC's reserves and future net revenue from TORC's reserves and pricing; "*Description of our Capital Structure – Share Capital – Preferred Shares*" as to amendments to our preferred shares; and "*Dividend Policy*" as to our dividend policy and the future payment of dividends.

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

- future dividend payments;
- timing of filing certain regulatory approvals;
- waterflood and alkaline surfactant polymer ("**ASP**") flood implementation opportunities;
- recovery factors;
- the performance characteristics of our oil and natural gas properties;
- expectation of future production rates, volumes and product mixes;
- projections of market prices and costs, and exchange and inflation rates;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions, development and optimization;
- treatment under governmental regulatory regimes and tax laws;
- expected timing of pipelines to be constructed and to be in service;
- expected timing of facilities and projects to be approved, constructed or completed;
- changes in regulatory regimes and the effects of such changes;
- potential effects of regulatory regimes; and
- our business plans and strategy.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- exploration, development and production risks;
- weakness in the oil and natural gas industry;
- volatility in foreign exchange rates;
- impacts of pandemics;
- market prices of oil and natural gas;
- differentials;
- fluctuation in the supply and demand for oil and natural gas;
- operational risks and liabilities inherent in oil and natural gas operations;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- our ability to market our oil and natural gas;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- uncertainties and changes in royalty regimes;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;

- the uncertainties in regard to the timing of our exploration and development program;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- water and carbon dioxide ("**CO_2**") supplies;
- cyber-security issues; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: commodity prices, differentials and royalty regimes; timing of production curtailments; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; availability of transportation; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

Non-GAAP Measures

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "resulting netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. We use "resulting netback" as a key performance indicator and it is used by us in operational and capital allocation decisions. It is determined by deducting royalties and production costs from average net production prices received. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings determined in accordance with generally accepted accounting principles in Canada as an indication of our performance.

WHITECAP RESOURCES INC.

We are the resulting entity following the completion of the reverse takeover of Spitfire and subsequent amalgamation with Spitfire on July 1, 2010 to form "Whitecap Resources Inc."

Spitfire was incorporated under the *Business Corporations Act* (Alberta) on August 30, 2001. On November 6, 2001, Spitfire amended and restated its articles to change its authorized share structure to include an unlimited number of common shares and an unlimited number of preferred shares. On March 31, 2004, Spitfire amalgamated pursuant to the *Business Corporations Act* (Alberta) with its wholly-owned subsidiary, Cashel Resources Inc. to form the amalgamated corporation, Spitfire Energy Ltd. On April 1, 2005, Spitfire purchased all of the issued and outstanding shares of, and then amalgamated with a private oil and gas company, Spitfire Exploration Ltd. pursuant to the *Business Corporations Act* (Alberta) to form Spitfire.

We were incorporated under the *Business Corporations Act* (Alberta) on June 3, 2008 as "1405340 Alberta Ltd.". On September 2, 2008, we amended our articles to change our name from 1405340 Alberta Ltd. to "Whitecap Resources Inc." and we commenced operations on September 17, 2009.

On October 15, 2010, we filed articles of amendment to effect a consolidation of our Common Shares on a basis of 10 pre-consolidated shares for every 1 Common Share. The consolidation was approved by our Shareholders at our annual general and special meeting held on September 14, 2010.

On February 24, 2021, we filed articles of amendment to increase the maximum number of our directors from nine to twelve to facilitate the appointment of a designated director agreed to by Whitecap and TORC, to our Board on closing of the TORC Transaction. The amendment was approved by our Shareholders at our special meeting held on February 18, 2021.

We have completed a number of corporate acquisitions since we commenced operations following which we have amalgamated the resulting subsidiary into Whitecap. We filed articles of amalgamation and amalgamated with the following acquired subsidiaries:

Date of Amalgamation	Name of Acquired Subsidiary
July 1, 2010	Spitfire
July 30, 2010	Onyx 2006 Inc.
April 20, 2011	Spry Energy Ltd.
February 10, 2012	Compass Petroleum Ltd.
April 23, 2012	Midway Energy Ltd.
April 30, 2013	Invicta Energy Corp.
January 6, 2014	Home Quarter Resources Ltd.
October 1, 2014	Forge Petroleum Corp.
October 1, 2014	Bashaw Oil Ltd.
January 1, 2015	1808039 Alberta Ltd.
May 1, 2015	Beaumont Energy Inc.
February 22, 2018	Capio Energy Inc.
January 1, 2021	Hyak Energy ULC
January 4, 2021	NAL
February 24, 2021	TORC

Whitecap has no material subsidiaries. Our head office is located at Suite 3800, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and our registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

Since our inception, we have grown from a junior, privately held, oil and gas company to a publicly traded, oil-weighted growth company that pays a monthly cash dividend to our Shareholders.

The following provides a summary of how our business has developed over the last three years.

Developments in 2018

We increased our monthly dividend by 5% to $0.0257 per Common Share ($0.3084 per Common Share annually) commencing with the January 2018 dividend.

On February 22, 2018, we completed the acquisition of all of the issued and outstanding shares of Capio Energy Inc. for an aggregate purchase price of $56.8 million in cash and we assumed Capio Energy Inc.'s $6.7 million working capital surplus.

On February 28, 2018, we appointed Mr. Ken Stickland as Chair of our Board of Directors.

On May 18, 2018, we commenced a normal course issuer bid to purchase, from time to time, up to 20,864,806 Common Shares on the open market through the facilities of the Toronto Stock Exchange and/or other Canadian exchanges. The normal course issuer bid terminated on May 17, 2019.

We increased our monthly dividend by 5% to $0.027 per Common Shares ($0.324 per Common Share annually) commencing with the June 2018 dividend.

In December 2018, our Board of Directors approved our 2019 capital program of $425 to $475 million.

Developments in 2019

We increased our monthly dividend by 5.6% to $0.0285 per Common Share ($0.342 per Common Share annually) commencing with the May 2019 dividend.

On May 21, 2019, we commenced a normal course issuer bid to purchase, from time to time, up to 20,657,914 Common Shares on the open market through the facilities of the Toronto Stock Exchange and/or other Canadian exchanges. The normal course issuer bid terminated on May 20, 2020.

On July 30, 2019, we created the Sustainability & Advocacy Committee of our Board to which the Board has delegated its responsibility for: (a) oversight of climate related and other sustainability-based risks and opportunities by reviewing, reporting and making recommendations to the Board on the development, implementation and monitoring of our policies, procedures, practises and strategies with respect to climate related issues and sustainability; and (b) oversight of advocacy initiatives to governments, communities and the public relating to policy issues affecting our sustainability or the Canadian energy industry.

On July 30, 2019, we appointed Mr. Brad Wall to our Board of Directors.

In October 2019, our Board of Directors approved our 2020 capital program of $360 to $380 million.

Developments in 2020

On January 15, 2020, we completed the acquisition of all of the issued and outstanding shares of Hyak Energy ULC for an aggregate purchase price of $16.2 million in cash, net of acquired working capital.

On March 17, 2020, we employed various proactive measures in response to the sharp decline in global commodity prices and the outbreak of the COVID-19 pandemic and reduced our 2020 capital program by approximately 44% to $200-210 million and also reduced our monthly dividend by 50% to $0.01425 per Common Share ($0.171 per Common Share annually) commencing with the May 2020 dividend.

On April 30, 2020, additional actions were taken in response to the sharp decline in global commodity prices and we reduced our 2020 capital program by a further $20 million to $190 million, immediately reduced operating expenses by $20 million and reduced general and administrative expenses by $8 million.

On May 21, 2020, we commenced a normal course issuer bid to purchase, from time to time, up to 20,406,799 Common Shares on the open market through the facilities of the Toronto Stock Exchange and/or other Canadian exchanges. Unless renewed, the normal course issuer bid will terminate on May 20, 2021.

On June 15, 2020, we published and posted to our website our 2020 environmental, social and governance report ("**Sustainability Report**") and established a target to reduce direct emissions intensity of 20% by 2023 (from 2019 levels).

Recent Developments

NAL Transaction

On January 4, 2021, we completed the NAL Transaction and issued approximately 58.3 million Common Shares. Further particulars with respect to the NAL Transaction are set forth in our material change report dated September 9, 2020 and which is filed on our SEDAR profile at *www.sedar.com.* The assets acquired by us pursuant to the NAL Transaction consisted of primarily light oil assets overlapping more than 80% of our asset base in west central Alberta, west central Saskatchewan and southeast Saskatchewan. Following completion of the NAL Transaction, NAL was amalgamated into us. For information with respect to the production and reserves acquired by us pursuant to the NAL Transaction, see "*Updates to Reserves Data – NAL Transaction*" below.

On closing of the NAL Transaction, we entered into an investor rights agreement (the "**Investor Rights Agreement**") and a registrations rights agreement (the "**Registration Rights Agreement**") with the NAL Vendor which provides the NAL Vendor with certain board observer rights, pro rata participation rights in future equity issuances and future registration rights.

TORC Transaction

On February 24, 2021, we completed the TORC Transaction and issued approximately 129.8 million Common Shares to the former TORC shareholders. Further particulars with respect to the TORC Transaction are set forth in our material change report dated December 17, 2020 and which is filed on our SEDAR profile at *www.sedar.com.* The assets acquired by us pursuant to the TORC Transaction consisted of primarily light-oil assets located in central Alberta, southeast Saskatchewan and southwest Manitoba including overlapping major assets in southeast Saskatchewan and central Alberta. Following completion of the TORC Transaction, TORC was amalgamated into us. In addition, Ms. Mary-Jo Case was added to our Board. For information with respect to the production and reserves acquired by us pursuant to the TORC Transaction, see "*Updates to Reserves Data – TORC Transaction*" below.

Credit Facility Increase

Concurrent with the closing of the TORC Transaction our Credit Facility was increased by $230 million to $1.405 billion from $1.175 billion. The Credit Facility is more particularly described under the heading "*Description of our Capital Structure – Credit Facility*".

Dividend Increase

In connection with the TORC Transaction, we have announced our intention to increase our monthly dividend from $0.01425 per Common Share to $0.01508 per Common Share ($0.18096 per Common Share annualized). The dividend increase is expected to be effective with the March 2021 dividend payable in April 2021, subject to the approval of our Board and satisfaction of the solvency tests under the *Business Corporations Act* (Alberta).

Significant Acquisitions

We did not complete any significant acquisitions during our most recently completed financial year.

The TORC Transaction, which was completed on February 24, 2021, constituted a significant acquisition under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*. We will file a business acquisition report regarding the TORC Transaction on our SEDAR profile at *www.sedar.com* within the required timing.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

Our business plan is to deliver profitable growth to our Shareholders over the long term under varying business conditions. Since inception we have executed our business plan by pursuing strategic acquisitions and carrying out development programs focusing on our core properties in northwest Alberta and British Columbia, west central Alberta, west central Saskatchewan, southwest Saskatchewan and southeast Saskatchewan. See "*General Description of our Business – Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Properties*". Once a property has been acquired, we pursue optimization and ongoing development and expansion opportunities.

We are focused on providing monthly dividends and per share growth on our existing assets enhanced by acquisitions.

The key attributes to our dividend growth strategy are as follows:

- provide dividends and targeted per share growth in production, reserves and funds flow;
- conservative total payout ratio and strong balance sheet;
- strong capital efficiencies in concentrated areas;
- predictable and stable production base;
- large light oil development drilling inventory; and
- disciplined and value focused management team.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years. Such prices are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes. See "*Risk Factors – Prices, Markets and Marketing*", "*Risk Factors – Hedging*", "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*" and "*Industry Conditions – Curtailment*".

Ongoing Acquisition and Disposition Activities

Potential Acquisitions

We evaluate potential acquisitions of all types of oil and natural gas and other energy related assets as part of our on-going asset portfolio management program. We are normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material and it is in the normal course of our business to routinely make offers on properties or acquisitions that fit within our business objectives.

Potential Dispositions

We evaluate potential dispositions of our oil and natural gas assets as part of our ongoing asset portfolio management program. In addition, we evaluate potential farm-out opportunities with other industry participants in respect of our oil and natural gas assets in circumstances where we believe it is prudent to do so based on, among other things, our capital program, development plan timelines and the risk profile of such assets. We are normally in the process of evaluating several potential dispositions of our assets and farm-out opportunities at any one time, which individually or together could be material.

Environmental Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. Key environmental considerations include air quality and reduction of greenhouse gas emissions, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment, remediation and reclamation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation. We have internal procedures designed to ensure that detailed due diligence reviews to assess environmental liabilities and regulatory compliance are completed prior to proceeding with new acquisitions and developments.

Our environmental management program and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program is monitored by our health, safety and environmental committee and includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an asset integrity program; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response and clean-up program; a fugitive emission survey and repair program; and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as our oil and gas properties are abandoned. In 2020, expenditures for normal compliance with environmental regulations as well as expenditures for above normal compliance were not material.

Annually, we disclose an environmental social and governance ("**ESG**") table with performance data on material ESG issues. Every second year, we produce a fulsome sustainability report in accordance with sustainability reporting standards and documenting our assessment of risks, opportunities, progress and challenges as they relate to sustainability issues. The content, scope and methods used in our annual sustainability disclosures are informed by the Sustainability Accounting Standards Board, the Task Force on Climate-related Financial Disclosures and the Global Reporting Institute Standards. Our report includes indices that link elements of these three standards to report contents. Both the most recent data table and the 2020 Sustainability Report are available on our website.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2021 by the renegotiation or termination of contracts or subcontracts.

Competitive Conditions

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

We strive to be competitive by maintaining financial flexibility and by utilizing current technologies to enhance optimization, development and operational activities.

Human Resources

At December 31, 2020, we employed 278 full-time employees, including 166 office and 112 field employees.

Statement of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and natural gas information set forth below is based on the McDaniel Report dated February 11, 2021. The statement is effective as of December 31, 2020. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2020 as contained in the McDaniel Report. The reserves data summarizes the crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities.

McDaniel has confirmed that its evaluation has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged McDaniel to provide an evaluation of all of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

We completed the NAL Transaction and the TORC Transaction subsequent to December 31, 2020. As a result, the reserves data and other oil and natural gas information in this "*Statement of Reserves Data and Other Oil and Natural Gas Information*" does not include NAL or TORC. See "*Updates to Reserves Data – NAL Transaction*" and "*Updates to Reserves Data – TORC Transaction*" below which contains certain production and reserves information for TORC and NAL.

All of the reserves specified in the McDaniel Report are in Canada and, specifically, in the Provinces of Alberta, Saskatchewan and British Columbia.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing the before income tax future net revenue from the McDaniel Report and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. The after tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different. Our consolidated financial statements for the year ended December 31, 2020 should be consulted for additional information regarding our taxes.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and

abandonment and reclamation costs. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Definitions and Notes to Reserves Data Tables

In the tables set forth below in "*Reserves Data (Forecast Prices and Costs)*", "*Updates to Reserves Data – NAL Transaction*" and "*Updates to Reserves Data – TORC Transaction*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**gross**" means:

   (a) in relation to an entity's interest in production and reserves, such entity's working interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

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

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

2. "**net**" means:

   (a) in relation to an entity's interest in production and reserves, such entity's working interest (operating and non-operating) share after deduction of royalties, plus our royalty interest in production or reserves;

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

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

   Reserve Categories

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

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

   (b) the use of established technology; and

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

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

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

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

4. "**economic assumptions**" means the forecast prices and costs used in the estimate:

Development and Production Status

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

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

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

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

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

(d) provide improved recovery systems.

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

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

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

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

   (c) dry hole contributions and bottom hole contributions;

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

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

8. "**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

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

10. "**forecast prices and costs**"

   These are future prices and costs that are:

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

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

11. Numbers may not add due to rounding.

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

13. We did not have any heavy crude oil reserves or synthetic oil or other products from non-conventional oil and gas during the year ended December 31, 2020.

Reserves Data (Forecast Prices and Costs)

RESERVES CATEGORY	SUMMARY OF OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS					
	LIGHT AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS (1)		NATURAL GAS LIQUIDS	
	GROSS (Mbbls)	NET (Mbbls)	GROSS (MMcf)	NET (MMcf)	GROSS (Mbbls)	NET (Mbbls)
PROVED:						
Developed Producing	168,312	145,968	166,037	150,960	12,295	10,564
Developed Non-Producing	1,882	1,769	1,787	1,711	85	73
Undeveloped	113,402	100,864	164,635	154,504	11,201	10,104
TOTAL PROVED	283,596	248,602	332,458	307,175	23,582	20,741
TOTAL PROBABLE	102,208	87,419	172,979	160,276	12,787	11,005
TOTAL PROVED PLUS PROBABLE	385,804	336,021	505,437	467,451	36,369	31,746

Note:

(1) Includes solution gas.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10%/YEAR (1)
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	($/BOE)
PROVED:						
Developed Producing	2,680,417	2,472,245	2,013,025	1,678,784	1,443,771	11.08
Developed Non-Producing	57,320	38,590	28,676	22,543	18,365	13.48
Undeveloped	1,969,750	1,092,564	607,628	323,464	147,931	4.44
TOTAL PROVED	4,707,487	3,603,400	2,649,329	2,024,792	1,610,067	8.27
TOTAL PROBABLE	4,270,736	2,195,627	1,358,820	937,167	692,678	10.86
TOTAL PROVED PLUS PROBABLE	8,978,223	5,799,027	4,008,149	2,961,959	2,302,744	8.99

Note:

(1) Unit values are based on net reserve values.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	2,604,517	2,443,765	2,001,483	1,673,785	1,441,478
Developed Non-Producing	42,666	31,847	25,406	20,885	17,491
Undeveloped	1,436,935	772,289	401,659	183,916	49,432
TOTAL PROVED	4,084,118	3,247,901	2,428,548	1,878,586	1,508,401
TOTAL PROBABLE	3,301,124	1,649,580	1,010,513	695,619	515,368
TOTAL PROVED PLUS PROBABLE	7,385,242	4,897,481	3,439,061	2,574,205	2,023,769

RESERVES CATEGORY	REVENUE (1) ($000s)	ROYALTIES (2) ($000s)	OPERATING COSTS ($000s)	DEVELOP-MENT COSTS ($000s)	ABANDON-MENT AND RECLAMATION COSTS (3) ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS								
TOTAL PROVED	20,526,472	3,244,046	7,360,456	3,564,507	1,649,976	4,707,487	623,369	4,084,118
TOTAL PROVED PLUS PROBABLE	29,346,011	4,724,989	9,891,689	4,069,900	1,681,211	8,978,223	1,592,981	7,385,242

Notes:

(1) Includes all product revenues and other revenues as forecast.
(2) Royalties include Crown, freehold and overriding royalties, mineral tax and Saskatchewan Corporation Capital Tax Surcharge.
(3) For more information, see "*Statement of Reserves Data and Other Oil and natural Gas Information – Significant Factors or Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs*".

PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE (1) ($/Bbl)	UNIT VALUE (1) ($/Mcf)
FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS			
TOTAL PROVED:			
Light and Medium Crude Oil (2)	2,629,618	10.58	
Conventional Natural Gas (3)	19,711		0.89
	2,649,329		
TOTAL PROVED PLUS PROBABLE			
Light and Medium Crude Oil (2)	3,981,267	11.85	
Conventional Natural Gas (3)	26,882		0.88
	4,008,149		

Notes:

(1) Unit values are calculated using the 10% discount rate divided by the major product type net reserves for each group.
(2) Includes solution gas and other associated by-products.
(3) Includes by-products.

Pricing Assumptions

The forecast cost and price assumptions in this statement for our reserves assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

The forecast of prices, inflation and exchange rates provided in the table below were computed using the average of the forecasts ("**IQRE Average Forecast**") by McDaniel, GLJ Petroleum Consultants and Sproule. The IQRE Average Forecast is dated January 1, 2021. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs.

Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the McDaniel Report were as follows:

Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Hardisty Bow River 25° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	AECO Gas Price ($Cdn/MMbtu)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	INFLATION RATES (2) %/Year	EXCHANGE RATE (3) ($US/$Cdn)
	SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS (1)								
	OIL				**NATURAL GAS**	**NATURAL GAS LIQUIDS**			
Forecast									
2021	47.17	55.76	45.36	39.87	2.78	18.18	26.36	-	0.768
2022	50.17	59.89	48.96	43.20	2.70	21.91	32.85	1.3	0.765
2023	53.17	63.48	52.91	46.86	2.61	24.57	39.20	2.0	0.763
2024	54.97	65.76	54.95	48.67	2.65	25.47	40.65	2.0	0.763
2025	56.07	67.13	56.05	49.65	2.70	26.00	41.50	2.0	0.763
2026	57.19	68.53	57.16	50.65	2.76	26.54	42.36	2.0	0.763
2027	58.34	69.95	58.30	51.67	2.81	27.09	43.24	2.0	0.763
2028	59.50	71.40	59.47	52.71	2.87	27.65	44.14	2.0	0.763
2029	60.69	72.88	60.66	53.76	2.92	28.23	45.06	2.0	0.763
2030	61.91	74.34	61.87	54.84	2.98	28.79	45.96	2.0	0.763
2031	63.15	75.83	63.10	55.94	3.04	29.37	46.88	2.0	0.763
2032	64.41	77.34	64.37	57.05	3.10	29.95	47.82	2.0	0.763
2033	65.70	78.89	65.65	58.20	3.16	30.55	48.77	2.0	0.763
2034	67.01	80.47	66.97	59.36	3.23	31.16	49.75	2.0	0.763
2035	68.35	82.08	68.31	60.55	3.29	31.79	50.74	2.0	0.763
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.763

Notes:

(1) As at January 1, 2021.
(2) Inflation rate for costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2020, excluding price risk management activities, were $42.19/Bbl for light and medium crude oil, $2.39/Mcf for conventional natural gas, and $16.75/Bbl for natural gas liquids.

Reserves Reconciliation

	LIGHT AND MEDIUM CRUDE OIL PROVED (Mbbls)	LIGHT AND MEDIUM CRUDE OIL PROBABLE (Mbbls)	LIGHT AND MEDIUM CRUDE OIL PROVED PLUS PROBABLE (Mbbls)	CONVENTIONAL NATURAL GAS (5) PROVED (MMcf)	CONVENTIONAL NATURAL GAS (5) PROBABLE (MMcf)	CONVENTIONAL NATURAL GAS (5) PROVED PLUS PROBABLE (MMcf)
	RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE FORECAST PRICES AND COSTS					
December 31, 2019	283,789	101,197	384,986	334,154	180,091	514,244
Extensions & Improved Recovery (1)	13,317	6,037	19,353	9,452	5,873	15,325
Technical Revisions (2)	3,524	(13,384)	(9,860)	1,062	(39,199)	(38,137)
Discoveries	-	-	-	-	-	-
Acquisitions (3)	11,909	7,256	19,165	36,998	25,633	62,631
Dispositions	(1)	-	(2)	(1)	1	-
Economic Factors (4)	(9,670)	1,103	(8,567)	(24,998)	581	(24,417)
Production	(19,272)	-	(19,272)	(24,209)	-	(24,209)
December 31, 2020	283,596	102,208	385,804	332,458	172,979	505,437

Notes:

(1) The extensions and improved recovery amount includes all new wells drilled and booked during the year and any reserves changes directly attributable to enhanced oil recovery activities.
(2) The technical revisions amount includes all changes in reserves due to well performance and all previously booked wells which were drilled during the year.

(3) The acquisitions amount is the estimate of reserves at December 31, 2020 plus any production from the acquisition dates to December 31, 2020.
(4) The economic factors amount is the change in reserves due exclusively to a change in pricing.
(5) Includes solution gas volumes.

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE FORECAST PRICES AND COSTS NATURAL GAS LIQUIDS	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)
December 31, 2019	23,023	12,937	35,960
Extensions & Improved Recovery (1)	623	344	967
Technical Revisions (2)	1,529	(1,841)	(312)
Discoveries	-	-	-
Acquisitions (3)	1,796	1,245	3,041
Dispositions	-	-	-
Economic Factors (4)	(1,565)	102	(1,464)
Production	(1,823)	-	(1,823)
December 31, 2020	23,582	12,787	36,369

Notes:

(1) The extensions and improved recovery amount includes all new wells drilled and booked during the year and any reserves changes directly attributable to enhanced oil recovery activities.
(2) The technical revisions amount includes all changes in reserves due to well performance and all previously booked wells which were drilled during the year.
(3) The acquisitions amount is the estimate of reserves at December 31, 2020 plus any production from the acquisition dates to December 31, 2020.
(4) The economic factors amount is the change in reserves due exclusively to a change in pricing.

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years.

TIMING OF INITIAL PROVED UNDEVELOPED RESERVES ASSIGNMENT GROSS RESERVES FIRST ATTRIBUTED BY YEAR						
	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2018	13,072	97,615	19,435	114,552	1,806	8,879
2019	13,083	101,575	35,387	142,938	1,703	9,776
2020	12,229	113,402	8,176	164,635	583	11,201

Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. The McDaniel Report has assigned 152.0 MMboe of proved undeveloped reserves with $2,825.6 million of associated undiscounted capital.

All of our proved undeveloped reserves are in our core areas where we are actively spending capital to develop those properties. As such, we expect that the large majority of our booked undeveloped projects will be completed within a three year time frame and that substantially all of our currently booked undeveloped projects will be completed within a five year time frame, other than undeveloped projects related to our Weyburn property which will be completed within an eight to ten year time frame, consistent with the long term development nature of miscible CO_2 floods. For more information, see "*Significant Factors or Uncertainties Affecting Reserves Data – Future Development Costs*". There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years.

TIMING OF INITIAL PROBABLE UNDEVELOPED RESERVES ASSIGNMENT GROSS RESERVES FIRST ATTRIBUTED BY YEAR						
	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2018	4,929	46,057	10,302	64,027	1,071	5,290
2019	11,318	54,273	53,154	262,720	3,057	18,142
2020	5,938	58,047	5,956	120,880	374	8,514

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. The McDaniel Report has assigned 86.7 MMboe of probable undeveloped reserves with $503.8 million of associated undiscounted capital.

All of our probable undeveloped reserves are in our core areas where we are actively spending capital to develop those properties. As such, we expect that the large majority of our booked undeveloped projects will be completed within a three year time frame and that substantially all of our currently booked undeveloped projects will be completed within a five year time frame consistent with our proved undeveloped reserves, other than undeveloped projects related to our Weyburn property which will be completed within an eight to ten year time frame, consistent with the long term development nature of miscible CO_2 floods.

Significant Factors or Uncertainties Affecting Reserves Data

Changes in future commodity prices relative to the forecasts provided under "*Statement of Reserves Data and Other Oil and Natural Gas Information – Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above we do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes, abandonment and reclamation costs and well performance that are beyond our control. See "*Risk Factors*".

Abandonment and Reclamation Costs

In connection with our operations, we will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. We budget for and recognize as a liability the estimated present value of the future decommissioning liabilities associated with our property, plant and equipment. Our overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing wells for reactivation, recompletion or sale and conduct systematic abandonment programs for those wells that do not meet our criteria. A portion of our liabilities are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves.

As at December 31, 2020 we had 7,834.2 net wells for which we expect to incur abandonment and reclamation costs. The McDaniel Report deducted $1,681.2 million (undiscounted) and $208.6 million (10% discount) for abandonment and reclamation costs for all of our facilities, pipelines and wells including those without reserves.

Future Development Costs

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

	FORECAST PRICES AND COSTS	
YEAR	TOTAL PROVED RESERVES ($000s)	TOTAL PROVED PLUS PROBABLE RESERVES ($000s)
2021	309,595	322,155
2022	508,464	521,500
2023	626,859	679,849
2024	567,548	617,478
2025	531,465	633,810
Remaining	1,020,576	1,295,107
Total (Undiscounted)	3,564,507	4,069,900

We expect to fund the development costs of our reserves through a combination of funds flow and debt. There can be no guarantee that funds flow will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the McDaniel Report. Failure to develop those reserves could have a negative impact on our future funds flow.

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic.

Other Oil and Natural Gas Information

Principal Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2020. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Northwest Alberta and British Columbia

Our Deep Basin properties, which include Karr, Simonette, Kakwa, Elmworth and Wapiti, are located southwest of Grande Prairie, Alberta. The primary reservoirs being developed are the Cardium, Montney and Dunvegan which are all light sweet oil. All reservoirs are characterized by thick oil columns with significant oil in place per unit area. This area is being developed with horizontal multi-fracture wells, including extended reach horizontals.

Our Boundary Lake property is located primarily in northeast British Columbia on the Alberta/British Columbia border, just east of Fort St. John, and is characterized by a steady and predictable production base within an active waterflood. The key characteristics of this legacy oil pool are high working interest, operated, light oil and a consistent low decline over the past 30 years. Our Valhalla North property is located in the Peace River Arch area of Alberta and has a solid base production in the Montney Sexsmith oil pool and associated waterflood and the Charlie Lake light oil reservoirs. Additional expansion opportunities in the Montney Resource oil play are also in our development plans.

Southeast Saskatchewan

Our Weyburn property is located in southeast Saskatchewan and includes a 62.1% operated working interest in the Weyburn Unit. The key characteristics of this asset are light gravity sour oil primarily from the Midale reservoir. The Weyburn Unit has been in existence since the 1950's when it was discovered. Waterflood operations commenced in the 1960's with a world class CO_2 enhanced oil recovery development commencing in 2000. There remain significant expansion opportunities to expand the Weyburn CO_2 flood, and further mitigate an already very low base decline rate and greenhouse gas ("**GHG**") emission intensity.

Southwest Saskatchewan

Our Southwest Saskatchewan suite of assets are concentrated just west of Swift Current and are characterized by medium gravity crude production from a predictable low decline base production complemented by several growth opportunities. Multiple active waterfloods are sustaining the area as well as three established polymer floods with over 90% of production coming from enhanced recovery. Additional waterflood and ASP potential exists, and will be part of our ongoing development programs. The primary formations being targeted in the area are Atlas, Success, Roseray, and Shaunavon. These properties had not seen significant development prior to our activities, and we combine horizontal wells, multistage frac technology, and conventional production and enhanced oil recovery optimization efforts to maximize production and oil recovery from these pools.

West Central Saskatchewan

Our Lucky Hills, Whiteside, Kerrobert, and Eagle Lake areas are located in west central Saskatchewan. The primary reservoir that we are currently focused on developing is the Viking resource light oil play. The key characteristics of this play is light 38° – 40° API oil, predictable geology and production profiles as well as consistent and repeatable economics. Lucky Hills and Whiteside are characterized by prolific horizontal primary oil development wells with quick payouts and a predictable high netback production profile. The Eagle Lake property is characterized by predictable low decline waterflood supported production from legacy vertical and horizontal infill wells. Additional development is ongoing through the drilling of infill horizontal wells and reactivation of the waterflood to increase reserve recoveries.

West Central Alberta

Our Cardium producing areas are primarily located in the Pembina, Garrington, Ferrier and Willesden Green areas of West Central Alberta. The key characteristics of the Cardium in these areas are light 40° API oil with geology and oil resource mapping that is well defined with legacy vertical wells. There is no significant mobile formation water in the Cardium which results in predictable declines and production profiles. Several of these legacy pools are under active waterflood which has the impact of lowering pool declines and increasing the percentage of the oil in place which is recoverable. Performance of these waterfloods has been improving with re-development with horizontal wells as well as optimization efforts.

Oil and Natural Gas Wells

The following table summarizes, as at December 31, 2020, our interests in producing wells and in non-producing wells.

	PRODUCING WELLS [1]				NON-PRODUCING WELLS [1]			
	OIL		NATURAL GAS		OIL		NATURAL GAS	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	1,072	888.6	29	10.1	534	429.6	212	138.9
British Columbia	206	193.8	15	7.0	132	126.3	17	11.5
Saskatchewan	3,261	2,385.1	3	2.6	2,807	2,179.1	102	77.5
Total	4,539	3,467.5	47	19.8	3,473	2,735.0	331	227.9

Note:

(1) Does not include injection wells or service wells.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2020:

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES (1)(2)(3)	
	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	199,502	133,374	366,322	256,064	565,824	389,438
British Columbia	25,921	18,043	63,103	55,781	89,024	73,824
Saskatchewan	112,501	88,882	334,429	236,073	446,929	324,955
Total	337,924	240,299	763,854	547,918	1,101,777	788,217

Notes:

(1) Includes our interest in approximately 97,074 gross (69,075 net) acres of unproved property land holdings. See "*Properties with no Attributed Reserves*" below.

(2) Rights to explore, develop and exploit 25,918 gross (20,622 net) acres of our land holdings could expire by December 31, 2021 if not continued. We have no material work commitments on such properties and where we determine prudent to do so, we can extend expiring leases by either making the necessary applications to extend or performing the necessary work.

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

Properties with no Attributed Reserves

The following table sets out our unproved properties as at December 31, 2020:

	GROSS ACRES	NET ACRES
Alberta	10,865	7,731
British Columbia	53,146	37,817
Saskatchewan	33,063	23,527
Total	97,074	69,075

Note:

(1) Approximately 7,445 gross (5,924 net) acres of these land holdings could expire by December 31, 2021.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

Our business model focuses on predictable and lower decline production with little to no capital allocated to the acquisition, exploration or development of our properties with no attributed reserves. We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. However, our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes, all of which are beyond our control. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See "*Significant Factors or Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs*" and "*Risk Factors*".

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties.

We may use certain financial instruments to hedge exposure to commodity price fluctuations on a portion of our crude oil and natural gas production. For further information, see note 5 to our consolidated financial statements for the year ended December 31, 2020. See "*Risk Factors – Hedging*".

Tax Horizon

Based on estimated 2021 funds flow and capital expenditures, we do not expect to be cash taxable in 2021. We currently estimate that we will not become taxable until at least 2025, using forward benchmark prices in effect on the date of this Annual Information Form.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2020:

EXPENDITURE	YEAR ENDED DECEMBER 31, 2020 ($000s)
Property acquisition costs:	
Proved properties	278
Unproved properties [(1)]	5,381
Corporate acquisition costs	18,417
Exploration costs [(2)]	1,793
Development costs [(3)]	185,597
Other	8,218
Total	219,684

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(3) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.

Exploration and Development Activities

The following table sets forth the gross and net development wells in which we participated during the year ended December 31, 2020.

	DEVELOPMENT	
	GROSS	NET
Natural Gas	-	-
Light and Medium Crude Oil	72	50.8
Service Wells	8	6.9
Dry	-	-
Total	80	57.6

In 2021, we expect to drill approximately 20 oil wells in Alberta, 2 natural gas wells in Alberta, 77 oil wells in Saskatchewan and 1 oil wells in British Columbia.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2021, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Statement of Reserves Data and Other Oil and Natural Gas Information – Pricing Assumptions*".

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	CONVENTIONAL NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	BOE (Boe/d)
Total Proved				
Northwest Alberta and British Columbia	10,006	29,065	2,780	16,732
Southeast Saskatchewan	13,954	17	690	14,386
Southwest Saskatchewan	12,397	1,385	6	12,632
West Central Alberta	6,439	24,756	2,557	12,355
West Central Saskatchewan	7,593	8,245	325	9,261
Other minor areas	28	9	1	30
Total	50,417	63,477	6,359	65,396
Total Proved plus Probable				
Northwest Alberta and British Columbia	10,644	30,717	2,964	17,770
Southeast Saskatchewan	14,092	19	738	14,553
Southwest Saskatchewan	12,954	1,470	7	13,203
West Central Alberta	6,910	26,316	2,747	13,200
West Central Saskatchewan	8,411	9,054	358	10,244
Other minor areas	29	9	1	31
Total	53,041	67,585	6,815	69,002

Production History

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2020:

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	CONVENTIONAL NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	BOE [(1)] (Boe/d)
Northwest Alberta and British Columbia	10,277	28,154	2,123	17,093
Southwest Saskatchewan	14,093	2,434	5	14,503
Southeast Saskatchewan	13,777	12	518	14,297
West Central Alberta	6,833	27,616	2,070	13,506
West Central Saskatchewan	7,655	7,925	266	9,242
Other minor areas	21	4	-	21
Total	52,656	66,146	4,982	68,662

Note:

(1) We did not produce any heavy oil during the year ended December 31, 2020.

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

	FOR THE THREE MONTHS ENDED 2020				YEAR ENDED 2020
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	DECEMBER 31
Average Daily Production (1)(2)					
Light and Medium Crude Oil (Bbls/d)	56,631	54,067	51,456	48,527	52,656
Natural Gas Liquids (Bbls/d)	5,077	5,288	4,693	4,874	4,982
Conventional Natural Gas (Mcf/d)	70,466	68,712	63,191	62,289	66,146
Combined (Boe/d)	73,452	70,807	66,681	63,783	68,662
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	47.48	26.55	47.67	47.52	42.19
Natural Gas Liquids ($/Bbl)	12.30	13.17	19.57	22.48	16.75
Conventional Natural Gas ($/Mcf)	2.18	2.16	2.44	2.84	2.39
Combined ($/Boe)	39.54	23.35	40.47	40.64	35.88
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	7.47	2.26	7.19	7.30	6.03
Natural Gas Liquids ($/Bbl)	2.43	2.56	2.98	3.67	2.90
Conventional Natural Gas ($/Mcf)	(0.10)	0.10	(0.16)	0.06	(0.02)
Combined ($/Boe)	5.84	2.02	5.61	5.89	4.82
Production Costs (3)(4)(5)					
Light and Medium Crude Oil ($Bbl)	17.02	15.88	16.87	16.66	16.61
Natural Gas Liquids ($/Bbl)	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	0.25	0.26	0.26	0.29	0.26
Combined ($/Boe)	14.53	13.57	14.46	14.23	14.20
Resulting Netback Received					
Light and Medium Crude Oil ($/Bbl)	22.99	8.40	23.61	23.57	19.55
Natural Gas Liquids ($/Bbl)	9.87	10.61	16.59	18.81	13.85
Conventional Natural Gas ($/Mcf)	2.03	1.79	2.34	2.49	2.15
Combined ($/Boe)	19.17	7.76	20.40	20.53	16.87

Notes:

(1) Before the deduction of royalties.
(2) We did not produce any heavy oil during the year ended December 31, 2020.
(3) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between product types.
(4) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(5) Production costs attributable to natural gas liquids have been included in the light and medium crude oil and conventional natural gas production cost amounts.

Updates to Reserves Data – NAL Transaction

On January 4, 2021, we completed the NAL Transaction. The assets acquired by us pursuant to the NAL Transaction consisted of primarily light oil assets overlapping more than 80% of our asset base in west central Alberta, west central Saskatchewan and southeast Saskatchewan.

Reserves Data (Forecast Prices and Costs)

The information set forth below is based on the McDaniel NAL Report dated February 11, 2021 and is effective as of December 31, 2020.

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2020 as contained in the McDaniel NAL Report. The reserves data summarizes NAL's crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. McDaniel has confirmed that its evaluation has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. McDaniel was engaged by us to provide an evaluation of all of NAL's proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The McDaniel NAL Report was prepared by McDaniel for Whitecap. As a result, Whitecap participated in the preparation of the McDaniel NAL Report and reviewed the reserves data with McDaniel in conjunction with the preparation thereof.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the reserves acquired from NAL. There is no assurance that the forecast price and cost assumptions contained in the McDaniel NAL Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" above in conjunction with the following tables and notes. The recovery and reserve estimates on the properties described below are estimates only. The actual reserves on these properties may be greater or less than those calculated. See "*Risk Factors*".

All of the reserves specified in the McDaniel NAL Report are in Canada and, specifically, in the Provinces of Alberta and Saskatchewan. NAL did not have any heavy crude oil reserves or synthetic oil or other products from non-conventional oil and gas during the year ended December 31, 2020.

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL GROSS (Mbbls)	LIGHT AND MEDIUM CRUDE OIL NET (Mbbls)	CONVENTIONAL NATURAL GAS [(1)] GROSS (MMcf)	CONVENTIONAL NATURAL GAS [(1)] NET (MMcf)	NATURAL GAS LIQUIDS GROSS (Mbbls)	NATURAL GAS LIQUIDS NET (Mbbls)
	SUMMARY OF OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS					
PROVED:						
Developed Producing	15,444	14,643	148,551	134,394	9,751	7,995
Developed Non-Producing	-	-	3,655	3,159	80	68
Undeveloped	1,340	1,220	2,600	2,287	319	274
TOTAL PROVED	16,784	15,863	154,806	139,840	10,150	8,338
TOTAL PROBABLE	4,689	4,364	39,335	35,702	2,484	2,119
TOTAL PROVED PLUS PROBABLE	21,473	20,227	194,141	175,542	12,634	10,457

Note:

(1) Includes solution gas.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10%/YEAR [(1)] ($/BOE)
PROVED:						
Developed Producing	16,043	269,000	281,812	262,623	241,398	6.26
Developed Non-Producing	3,493	1,812	823	197	(219)	1.38
Undeveloped	19,120	12,635	8,350	5,364	3,194	4.45
TOTAL PROVED	38,656	283,447	290,985	268,185	244,373	6.13
TOTAL PROBABLE	234,557	150,531	107,278	81,939	65,671	8.63
TOTAL PROVED PLUS PROBABLE	273,213	433,978	398,263	350,124	310,044	6.64

Note:

(1) Unit values are based on net reserve values.

Pricing Assumptions

The reserves data set forth above used the same pricing and inflation rate assumptions as the McDaniel Report as set forth above under "*Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions*".

Updates to Reserves Data – TORC Transaction

On February 24, 2021, we completed the TORC Transaction. The assets acquired by us pursuant to the TORC Transaction consisted of primarily light-oil assets located in central Alberta, southeast Saskatchewan and southwest Manitoba including overlapping major assets in southeast Saskatchewan and central Alberta.

Reserves Data (Forecast Prices and Costs)

The information set forth below is based on the Sproule Report dated February 22, 2021 and is effective as of December 31, 2020.

The reserves data set forth below is based upon an evaluation by Sproule with an effective date of December 31, 2020 as contained in the Sproule Report. The reserves data summarizes TORC's crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. Sproule has confirmed that its evaluation has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. Sproule was engaged by TORC to provide an evaluation of all of TORC's proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The Sproule Report was prepared by Sproule for TORC. Whitecap did not participate in the preparation of the Sproule Report but has reviewed the reserves data with Sproule in conjunction with the preparation thereof.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the reserves acquired from TORC. There is no assurance that the forecast price and cost assumptions contained in the Sproule Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" above in conjunction with the following tables and notes. The recovery and reserve estimates on the properties described below are estimates only. The actual reserves on these properties may be greater or less than those calculated. See "*Risk Factors*".

	SUMMARY OF OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2020 FORECAST PRICES AND COSTS					
	LIGHT AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS (1)		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	GROSS (Mbbls)	NET (Mbbls)	GROSS (MMcf)	NET (MMcf)	GROSS (Mbbls)	NET (Mbbls)
PROVED:						
Developed Producing	38,137	34,220	36,959	33,722	2,939	2,598
Developed Non-Producing	2,704	2,449	3,890	3,499	217	179
Undeveloped	22,527	20,762	30,584	27,900	1,922	1,743
TOTAL PROVED	63,369	57,431	71,433	65,121	5,078	4,521
TOTAL PROBABLE	36,958	33,152	50,335	45,256	3,181	2,807
TOTAL PROVED PLUS PROBABLE	100,327	90,582	121,768	110,377	8,259	7,328

Note:

(1) Includes solution gas.

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10%/YEAR (1) ($/BOE)
	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					
PROVED:						
Developed Producing	426,129	550,065	507,668	453,280	406,700	11.96
Developed Non-Producing	68,712	52,192	41,323	33,717	28,134	12.87
Undeveloped	388,274	237,469	142,913	83,419	44,822	5.26
TOTAL PROVED	883,115	839,725	691,904	570,416	479,657	9.50
TOTAL PROBABLE	1,122,534	684,750	459,810	330,650	249,941	10.57
TOTAL PROVED PLUS PROBABLE	2,005,649	1,524,475	1,151,714	901,066	729,598	9.90

Note:

(1) Unit values are based on net reserve values.

Pricing Assumptions

The reserves data set forth above used the same pricing and inflation rate assumptions as the McDaniel Report as set forth above under "*Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions*".

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

As at the date hereof, we have a $1.405 billion credit facility with a syndicate of lenders. The Credit Facility consists of a $1.33 billion revolving syndicated facility and a $75 million revolving operating facility, with a maturity date of May 31, 2023. Prior to any anniversary date, being May 31 of each year, we may request an extension of the then current maturity date, subject to approval by the banks. Following the granting of such extension, the term to maturity of the Credit Facility shall not exceed four years. The Credit Facility provides that advances may be made by way of direct advances, banker's acceptances or letters of credit/guarantees. The Credit Facility bears interest at the bank's prime lending or bankers' acceptance rates plus applicable margins. The applicable margin charged by the bank is dependent upon our debt to earnings before interest, taxes, depreciation and amortization "EBITDA" ratio for the most recent quarter. The bankers' acceptances bear interest at the applicable banker's acceptance rate plus an explicit stamping fee based upon our debt to EBITDA ratio. The Credit Facility is secured by a floating charge debenture on our assets.

In the second quarter of 2018, as part of our annual credit facility review, the Credit Facility transitioned from a borrowing-based structure with lending capacity re-determined on a semi-annual basis, to a financial covenant-based structure with an extendible four-year term governed by our existing financial covenants.

The following table lists our financial covenants as at December 31, 2020:

Covenant Description		December 31 2020
	Maximum Ratio	
Debt to EBITDA (1) (2)	4.00	2.21
	Minimum Ratio	
EBITDA to interest expense (1)	3.50	11.15

Notes:

(1) The EBITDA used in the covenant calculation is adjusted for non-cash items, transaction costs and extraordinary and non-recurring items such as material acquisitions or dispositions.
(2) The debt used in the covenant calculation includes bank indebtedness, letters of credit, and dividends declared.

As of December 31, 2020, we were compliant with all covenants provided for in the lending agreement. Copies of our credit agreements may be accessed through our SEDAR profile at *www.sedar.com*.

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that, if at both the date of declaration and payment of any such dividend, no default has occurred which has not been cured or waived and no default or event of default could reasonably be expected to be caused by or result from such declaration or payment.

Senior Secured Notes

We issued by way of private placement pursuant to a note purchase agreement: (a) $200 million in senior secured notes on January 5, 2017 which are repayable on January 5, 2022 and have an annual coupon rate of 3.46% ("**3.46% Notes**"); (b) $200 million in senior secured notes on May 31, 2017 which are repayable on May 31, 2024 and have an annual coupon rate of 3.54% ("**3.54% Notes**"); and (c) $195 million in senior secured notes on December 20, 2017 which are repayable on December 20, 2026 and have an annual coupon rate of 3.90% ("**3.90% Notes**"). The significant covenants under the Senior Secured Notes are the same as those under the Credit Facility, see "*Description of our Capital Structure – Credit Facility*".

Share Capital

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

Common Shares

We are authorized to issue an unlimited number of Common Shares without nominal or par value. Subject to the provisions of the *Business Corporations Act* (Alberta), holders of our Common Shares are entitled to one vote per share at meetings of our Shareholders. Subject to the rights of the holders of preferred shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by our Board of Directors and upon liquidation, dissolution or winding-up to receive, our remaining property.

Preferred Shares

We are authorized to issue an unlimited number of preferred shares without nominal or par value. Our Board of Directors may issue preferred shares at any time and from time to time in one or more series and shall fix the number of preferred shares in such series and determine the designation, rights, privileges, restrictions and conditions attaching to the preferred shares. The preferred shares shall be entitled to priority over our Common Shares and over any other of our shares ranking junior to the preferred shares with respect to priority in the payment of dividends if, as and when declared by our Board of Directors and the receipt of our remaining property upon liquidation, dissolution or winding-up. There are currently no preferred shares issued or outstanding.

At our upcoming annual and special meeting of shareholders to be held on April 21, 2021, shareholders will be asked to approve a special resolution authorizing an amendment to our articles to amend our preferred shares. Our Board believes that, given its discretion in determining the number of, and the designation, rights, privileges, restrictions and conditions attaching to the preferred shares including the voting rights (if any), it would also be in the interests of good corporate governance and best practices to amend our Articles to: (i) limit the maximum number of preferred shares that may be issued and outstanding and; (ii) limit the voting rights so that notwithstanding the current voting rights contained in the Articles, other than in the case of a failure to declare or pay dividends specified in any series of the preferred shares, the voting rights attached to the preferred shares shall be limited to one vote per preferred share at any meeting where the preferred shares and common shares vote together as a single class.

MARKET FOR SECURITIES

Trading Price and Volume

Our Common Shares trade on the Toronto Stock Exchange under the trading symbol "WCP". The following sets out the high and low trading prices and aggregate volume of trading on the Toronto Stock Exchange for the periods noted below for the Common Shares:

PERIOD	HIGH ($)	LOW ($)	VOLUME
2020			
January	5.69	4.66	51,639,997
February	4.95	3.61	40,049,579
March	4.13	0.73	159,628,061
April	2.00	1.07	129,813,367
May	2.35	1.45	105,696,008
June	2.90	2.01	87,535,165
July	2.435	2.10	40,855,669
August	2.90	2.19	49,891,392
September	2.79	2.335	66,498,198
October	2.75	2.18	49,307,046
November	4.14	2.375	69,160,792
December	5.33	3.86	82,314,087
2021			
January	5.40	4.46	64,325,599
February (1 – 23)	5.61	4.57	49,760,470

Prior Sales

During the year ended December 31, 2020 we issued a total of 3,029,510 share awards pursuant to our share award plan. On the payment date of such awards we have the sole discretion as to whether the awards shall be paid in cash, Common Shares from treasury or Common Shares purchased on the Toronto Stock Exchange. See note 14(d) to our annual consolidated financial statements for additional information.

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below.

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH WHITECAP	DIRECTOR OR OFFICER SINCE	PRINCIPAL OCCUPATION
Mary-Jo Case (1)(3) Calgary, Alberta	Director	February 2021	Independent businesswoman with over thirty-four years of experience in the oil and gas industry. Prior to her retirement in 2015, Ms. Case was a member of the Senior Management Committee as the Senior Vice President Land and Human Resources, and was the Vice President, Land at Canadian Natural Resources Limited during the period May 2002 to January 2015. Prior thereto, from May 1985 to April 2002 Ms. Case was the Manager Commercial Ventures and Land, the Coordinator Land, and a Negotiating Landman at PanCanadian Energy /

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH WHITECAP	DIRECTOR OR OFFICER SINCE	PRINCIPAL OCCUPATION
			PanCanadian Petroleum Limited. From October 1980 to May 1985 Ms. Case was a Land Administrator at Shell Canada Resources.
Heather J. Culbert (3)(5) Calgary, Alberta	Director	May 2017	Independent businesswoman, active philanthropist and a c-suite executive with executive expertise in IT, HR and M&A in the energy sector. Ms. Culbert currently serves as the Vice Chair of Export Development Canada (EDC), Board Chair of the Alberta Research and Innovation Advisory Committee (ARIAC), Founder of Board Ready Women (Calgary), Board Chair of the United Way World Leadership Council and as a director on the board of the Fraser Institute. From 1996 to 2006 Ms. Culbert was the Senior Vice President of Corporate Services with Enerplus Corporation. Prior thereto, she held senior management positions at Cody Energy, Suncor Energy and her own IT management consulting firm.
Grant B. Fagerheim (4)(5) Calgary, Alberta	President, Chief Executive Officer and Director	June 2008	Our President and Chief Executive Officer.
Gregory S. Fletcher (1)(2) Calgary, Alberta	Director	September 2010	Mr. Fletcher has over 40 years of experience in the oil and gas industry and is currently President of Sierra Energy Inc., a private oil and gas production company that he founded in 1997.
Daryl H. Gilbert (2)(4) Calgary, Alberta	Director	July 2015	Director and Investment Committee Member of JOG Capital Inc. since May 2008, a private equity energy investment firm. Mr. Gilbert is a professional engineer and is the former President and CEO of Gilbert Laustsen Jung Associates Ltd., now GLJ Petroleum Consultants Ltd., an independent engineering consulting firm based in Calgary.
Glenn A. McNamara (2)(3) Calgary, Alberta	Director	September 2010	President and Chief Executive Officer and a director of Heritage Resources LP, a wholly owned oil and gas business of Ontario Teachers' Pension Plan. From September 2010 to May 2016 he was the Chief Executive Officer and a director of PMI Resources Ltd. (formerly, Petromanas Energy Inc.), a public oil and gas company. From August 2005 to August 2010, Mr. McNamara was the President of BG Canada (part of the BG Group PLC, a public gas company with its head office in the United Kingdom, trading on the London Stock Exchange). Prior thereto he was the President of ExxonMobil Canada Energy (a wholly-owned subsidiary of ExxonMobil).
Stephen C. Nikiforuk (1) Calgary, Alberta	Director	August 2009	President of Loram 99 Corporation ("**Loram**") (a private company) since October 1, 2020 and prior thereto was the Controller then the General Manager of Loram since November, 2019. Prior thereto, President of MyOwnCFO Professional Corporation and MyOwnCFO Inc. from July 2009 to November 2019 (both private companies). Before then Mr. Nikiforuk was the Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011 and the Vice

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH WHITECAP	DIRECTOR OR OFFICER SINCE	PRINCIPAL OCCUPATION
			President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly, Kereco Energy Ltd.), a public oil and gas company, from January 2005 to March 2008.
Kenneth S. Stickland (1)(3) Calgary, Alberta	Chair	June 2013	Independent businessman. Prior to February 1, 2014, he was employed for 13 years by TransAlta Corporation, one of Canada's largest non-regulated power generation and wholesale marketing companies. At TransAlta he held the position of Chief Business Development Officer and prior to that was the Chief Legal Officer.
Bradley J. Wall (4)(5) Swift Current, SK	Director	July 2019	Mr. Wall has 18 years political experience and served as the Premier of Saskatchewan from November 2007 until February 2018. Mr. Wall is currently a special advisor at Osler, Hoskin & Harcourt LLP. Mr. Wall is an Advisory Board member of the Canadian Global Affairs Institute and the Canadian American Business Council. Mr. Wall is currently a partner at CW Cattle Company Ltd. Mr. Wall is also the Chair of the STARS Air Ambulance Fleet Replacement Board.
Grant A. Zawalsky (4)(5) Calgary Alberta	Director	June 2008	Managing Partner of Burnet, Duckworth & Palmer LLP, (Barristers and Solicitors) where he has been a partner since 1994.
Joel M. Armstrong Calgary, Alberta	Vice President, Production and Operations	May 2010	Our Vice President, Production and Operations.
Andrew Bullock Calgary, Alberta	Vice President, Exploration and Geosciences	June 2019	Our Vice President, Exploration and Geosciences; Our Vice President Geosciences since August 2016; Our Manager Development Geology since January 2015.
Darin R. Dunlop Strathmore, Alberta	Vice President, Engineering	November 2009	Our Vice President, Engineering.
Thanh C. Kang Calgary, Alberta	Chief Financial Officer	September 2009	Our Chief Financial Officer.
P. Gary Lebsack Calgary, Alberta	Vice President, Land	September 2009	Our Vice President, Land.
David M. Mombourquette Calgary, Alberta	Vice President, Business Development & IT	September 2009	Our Vice President, Business Development and IT.
Jeffery B. Zdunich Calgary, Alberta	Vice President, Finance and Controller	January 2015	Our Vice President, Finance and Controller since January 2015; Our Controller since March 2011.

Notes:

(1) Member of our Audit Committee.
(2) Member of our Reserves Committee.
(3) Member of our Corporate Governance & Compensation Committee.
(4) Member of our Health, Safety & Environment Committee.
(5) Member of our Sustainability & Advocacy Committee.

The term of office of each of our directors expires at the next annual meeting of our Shareholders.

As at February 24, 2021 our directors and executive officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 8.2 million Common Shares or approximately 1.4% of our issued and outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

Other than as set out below and to our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than thirty consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets other than described below.

Mr. Nikiforuk was a director of CYGAM Energy Inc., a junior public oil and gas company, which filed a voluntary assignment in bankruptcy under the *Bankruptcy and Insolvency Act* (Canada) in April 2015.

Mr. Gilbert was a director of LGX Oil and Gas Inc. ("**LGX**"), a public oil and gas company, from August, 2013 until June 2016. On June 7, 2016 a consent receivership order was granted by the Alberta Court of Queen's Bench (the "**Court**") upon an application by LGX's senior lender. LGX's stock was cease traded shortly thereafter. A receiver manager was appointed. Mr. Gilbert was a director of Connacher Oil & Gas Limited ("**Connacher**") from October 2014 until February 2019. On May 17, 2016, Connacher applied for and was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**"). On February 16, 2019 Connacher announced that it was proceeding to close on a credit bid transaction with its supporting lenders. Mr. Gilbert was a director of Trident Exploration Corp. ("**Trident**") from 2010 through year end 2018. On April 30, 2019 Trident announced it had ceased operations and had transferred all assets to the Alberta Energy Regulator. On May 3rd, 2019, PricewaterhouseCoopers LLP was appointed receiver. A liquidation process is currently underway.

Mr. Stickland was a director of Millennium Stimulation Services Ltd. ("**Millennium**") a private energy services company from May 3, 2012 to March 23, 2016. On March 24, 2016, the Court issued an order appointing KPMG Inc. as receiver and manager over Millennium's assets, undertakings and other properties.

Mr. Zawalsky was a director of Endurance Energy Ltd. ("**Endurance**"), a private natural gas company. Endurance filed for creditor protection under the CCAA on May 30, 2016. Mr. Zawalsky resigned as a director of Endurance on November 3, 2016 upon the sale of substantially all of the assets of Endurance. Mr. Zawalsky was a director of Zargon Oil & Gas Ltd. ("**Zargon**"), a public company engaged in the exploitation of oil, which filed a Notice of Intention to Make a Proposal to its creditors under the provisions of Part III, Division I of the Bankruptcy and Insolvency Act (Canada) on September 8, 2020. Mr. Zawalsky resigned as a director of Zargon on September 8, 2020.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

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

Our Board complies with all legal requirements relating to conflicts of interest and related party transactions. Directors must disclose their business and personal relationships with us and other companies or entities they have relationships with. If they have a conflict of interest with a matter to be discussed by our Board, they must not participate in any Board or committee discussions or vote on the matter. In addition, in certain cases, an independent committee of our Board may be formed to deliberate on such matters in the absence of the interested party.

Our audit committee is responsible for reviewing all related party transactions. In 2020, we amended the audit committee mandate to clarify that related party transactions are defined by applicable regulations and to state that the audit committee is responsible for ensuring the nature and extent of such transactions are properly disclosed.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of our Audit Committee charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The members of our Audit Committee are Mr. Nikiforuk (Chair), Mr. Stickland, Mr. Fletcher and Ms. Case, each of whom is independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*. The relevant education and experience of each Audit Committee member is outlined below:

Stephen C. Nikiforuk: *Loram 99 Corporation*

Mr. Nikiforuk became the President of Loram on October 1, 2020 and prior thereto, the Controller then the General Manager of Loram since November, 2019. Prior thereto he was the President of MyOwnCFO Professional Corporation and MyOwnCFO Inc. from July 2009 to November 2019, both private companies. Before then, Mr. Nikiforuk was the Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011 and the Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly, Kereco Energy Ltd.) a public oil and gas company, from January 2005 to March 2008.

Mr. Nikiforuk holds a B.B.A. with an accounting major from Saint Francis Xavier University. Mr. Nikiforuk is an active Chartered Professional Accountant, CA and in 2013 completed the Directors Education Program developed by the Institute of Corporate Directors and holds their ICD.D designation. In June 2016, Mr. Nikiforuk also obtained the Family Enterprise Advisor designation.

Mr. Nikiforuk is also a director of CanAir Nitrogen Inc., a private company that supplies the oil and gas industry in Alberta and British Columbia with cryogenic liquid nitrogen, and InPlay Oil Corp., a public light oil production and development company, and serves as both Lead Director and Audit Committee Chair for InPlay Oil Corp.

Kenneth S. Stickland: *Independent Businessman*

Mr. Stickland is an independent businessman. Prior to February 1, 2014, he was employed for 13 years by TransAlta Corporation, one of Canada's largest non-regulated power generation and wholesale marketing companies. At TransAlta he held the position of Chief Business Development Officer and prior to that was the Chief Legal and Business Development Officer and prior to that Chief Legal Officer. Prior thereto, Mr. Stickland was a partner with the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has over 30 years of experience in the area of commercial law with a specific focus on energy-related matters. Mr. Stickland has been the director of various associations and not-for-profit organizations. He has also been the director of several publicly listed companies. In these roles, Mr. Stickland has acquired significant experience and exposure to accounting and financial reporting issues.

Gregory S. Fletcher: *Sierra Energy Inc.*

Mr. Fletcher is an independent businessman involved in the oil and natural gas industry in western Canada. He is currently President of Sierra Energy Inc., a private oil and natural gas production company that he founded in 1997. Mr. Fletcher is also a director of Peyto Exploration & Development Corp., a public oil and natural gas company and a director of Calfrac Well Services Ltd., a public oilfield service company. In these roles, Mr. Fletcher has acquired significant experience and exposure to accounting and financial reporting issues. During 2009, Mr. Fletcher completed the Director Education Program developed by the Institute of Corporate Directors and the Rotman School of Management in conjunction with the Haskayne School of Business. Mr. Fletcher holds a BSc. in geology from the University of Calgary.

Mary-Jo Case: *Independent Businesswoman*

Ms. Case is an independent businesswoman with over thirty-four years of experience in the oil and gas industry. During her tenure, from 2002 to 2015, as a Senior Executive at Canadian Natural Resources Limited Ms. Case was a member of the Senior Management Committee gaining experience in finance, audit procedures and practices. Prior thereto Ms. Case obtained exposure in finance and audit through ever increasing management roles at PanCanadian Energy/PanCanadian Petroleum. From May 2018 to February 2021 Ms. Case was a Director of TORC Oil & Gas Ltd. and a member of the TORC Audit Committee. Ms. Case holds a Diploma in Legal Office Administration from Fanshawe College and in April of 2019 Ms. Case completed the Directors Education Program by the Institute of Corporate Directors and holds the ICD.D designation.

Pre-Approval of Policies and Procedures

Our Audit Committee has adopted a policy to review and pre-approve any non-audit services to be provided to us by our external auditors and will consider the impact on the independence of such auditors. The Audit Committee delegated to the Audit Chair the authority to pre-approve non-audit services, provided that the Chair reports to the Audit Committee at the next scheduled meeting such pre-approval and the Chair complies with such other procedures as may be established by our Audit Committee from time to time.

External Auditor Service Fees

PricewaterhouseCoopers LLP are our auditors. PricewaterhouseCoopers LLP have been our auditors since October 2009. Fees we incurred with PricewaterhouseCoopers LLP for audit and non-audit services in the last two fiscal years are outlined in the following table.

YEAR	AUDIT FEES [1] ($)	AUDIT-RELATED FEES [2] ($)	TAX FEES [3] ($)	ALL OTHER FEES [4] ($)
2019	335,000	16,700	52,500	61,000
2020	306,000	40,000	30,000	-

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of our consolidated financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the consolidated 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" for assurance and related services that are reasonably related to the performance of the audit or review of our consolidated financial statements and are not reported as audit fees. Services provided in this category include due diligence assistance, and accounting consultations on proposed transactions.

(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, tax planning and tax advice.

(4) "All Other Fees" includes all other non-audit services, including review and consultations relating to debt agreements, filing statements, business acquisition reports, and prospectuses as well as French translation of filing documents.

Reliance on Exemptions

At no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of our Audit Committee.

Audit Committee Oversight

At no time since commencement to the most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by our Board of Directors.

DIVIDEND POLICY

Dividends and Dividend Policy

Cash dividends are made on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Shareholders of record on the last business day of each such calendar month or such other date as determined from time to time by us. Unless otherwise specified, all dividends paid or to be paid by us are designated as "eligible dividends" under the *Income Tax Act* (Canada) (the "**Tax Act**").

The following monthly cash dividends on our Common Shares were declared by us for the periods indicated below:

DATE RANGE	CASH DIVIDEND PER COMMON SHARE
May 2020 to February 2021	$0.01425
May 2019 to April 2020	$0.0285
June 2018 to April 2019	$0.0270
January 2018 to May 2018	$0.0257

We carefully monitor the impact of all issues affecting our business and, the necessity to adjust our monthly dividends and our capital programs as conditions evolve. Dividends will normally be pre-approved on a quarterly basis in the context of prevailing and anticipated commodity prices and reconfirmed when declared. During periods of volatile commodity prices, we may vary the dividend rate monthly. See "*General Development of our Business – Developments in 2018*", "*General Development of our Business – Developments in 2019*" and "*General Development of our Business – Developments in 2020*".

Our long term objective is to set our dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to grow our current production base. This in turn, is expected to provide a stronger base of funds flow leading to consistent dividends into the future. Our dividend policy is reviewed monthly and is based on a number of factors including current and future commodity prices, foreign exchange rates, our commodity hedging program, current operations and available investment opportunities.

Our Credit Facility and Senior Secured Notes contain restrictions on our ability to pay dividends in certain circumstances. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta). Pursuant to the *Business Corporations Act* (Alberta), after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities.

In connection with the TORC Transaction, we have announced our intention to increase our monthly dividend from $0.01425 per Common Share to $0.01508 per Common Share ($0.18096 per Common Share annualized). The dividend increase is expected to be effective with the March 2021 dividend payable in April 2021, subject to the approval of our Board and satisfaction of the solvency tests under the *Business Corporations Act* (Alberta).

Cash dividends are not guaranteed. Our historical cash dividends may not be reflective of future cash dividends, which will be subject to review by our Board of Directors taking into account our prevailing financial circumstances at the relevant time. Although we intend to make dividends of our available cash to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends, applicable law and other factors beyond our control. See "*Risk Factors – Dividends*".

INDUSTRY CONDITIONS

Companies operating in the 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; and 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 Western Canadian oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted.

Our assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of our upstream oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations 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.

Outlined below are 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 Western Canada, specifically in the provinces of Alberta, Saskatchewan, British Columbia, and Manitoba, where our assets are primarily located. While these matters do not affect our 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 ("**OPEC**") 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 by achieving approximately 99.5% compliance with the agreed production adjustment commitments. However, economic recovery has slowed due to a resurgence of COVID-19 and newly emerging virus variants in major economies.

Natural Gas

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

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. 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. We do not directly enter into contracts to export our production outside of Canada.

Transportation Constraints and Market Access

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.

Pipelines

Producers negotiate with pipeline operators to transport their products to market on a firm, spot 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.

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.

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 Corporation ("**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 United 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 November 2020 ministerial order will remain in place until permanent rule changes are approved.

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 change stabilized supply and pricing, particularly during periods of maintenance on the system. TC Energy received Government of Canada approval for an expansion to the NGTL System in October 2020, with pipeline construction activities expected to begin in January 2021 and a target in-service date of April 2022. The CER has started a process to determine whether it will extend the temporary service protocol. Final argument took place in late January 2021.

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 BC 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 (the "**BC EAO**") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier 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.

Curtailment

In December 2018, the Government of Alberta announced that it would mandate a short-term and temporary curtailment of provincial 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 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 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 United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**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 Western Canada's oil and gas industry at large, including our 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. 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, British Columbia and Saskatchewan 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 Indian 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. We do not have operations on Indian 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 Western 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.

British Columbia

Crown royalties

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

The Crown royalty rate for oil can be as high 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells, including low-productivity wells, to reflect higher per-unit costs of exploration and extraction. The Crown royalty rate for natural gas and NGLs in British Columbia varies depending on the characteristics of the specific substance and can be as high as 27%, depending on factors such as whether the gas is classified as conservation gas or non-conservation gas, the applicable reference price and select price.

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. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

For oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

Saskatchewan

Crown royalties

Crown royalties payable on the production of oil and natural gas in Saskatchewan are paid on a well-by-well basis. Producers of oil and natural gas receive royalty invoices from the Government on a monthly basis.

The Crown royalty payable on oil production is paid on a well-by-well basis and depends on a number of variables, including the type and vintage of oil, the quantity of oil produced in a given month, the average wellhead price and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 5% - 20% and the marginal royalty rate ranges from 25% - 45%. The Crown royalty payable on natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type and classification of the natural gas, the finished drilling date of the well and certain price adjustment factors. Based on these factors, the base royalty rate ranges from 0% - 20% and the marginal royalty rate ranges from 30% - 45%.

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. In addition, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor that depends on the classification of the petroleum substance produced. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

Resource Surcharge

In addition to royalties, certain entities operating in Saskatchewan must pay a tax, known as a "**Resource Surcharge**", on the value of resources sales. The Resource Surcharge rate is 3% of the sales value of all oil and natural gas produced from wells drilled in Saskatchewan before October 1, 2002, and 1.7% for any wells drilled thereafter.

Manitoba

Crown royalties

The Crown royalty payable on oil production in Manitoba depends on the classification of the oil, which depends on variables such as the age and characteristics of the well, including whether the well is a vertical or horizontal well. Based on these factors, the royalty rate can be as high as approximately 43% of monthly production from a well or allocated to a spacing unit or unit tract, as applicable. The Crown royalty payable on natural gas production is a flat 12.5% of monthly revenue.

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. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale between 0% and approximately 40% and is based on monthly production volume and varies with the classification of the oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month.

Regulatory Authorities and Environmental Regulation

General

The Western Canadian oil and gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and 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 and the hearing is expected to take place in the first half of 2021.

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. We routinely conduct hydraulic fracturing in our drilling and completion programs. 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 "**Seismic Protocol Regions**") We do have operations in Brazeau. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the OGAA, the BC Commission has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BC Commission to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

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

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**").

An updated *Environmental Assessment Act* came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the BC EAO will consider the environmental, health, cultural, social and economic effects of a proposed project.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the statute governing the regulation of resource development operations in the province, along with *The Oil and Gas Conservation Regulations, 2012* and *The Petroleum Registry and Electronic Documents Regulations*. The Government of Saskatchewan has implemented a number of operational requirements, including an increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex Database.

Manitoba

In Manitoba, the Petroleum Branch of the Department of Growth, Enterprise and Trade develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of oil and natural gas resources. Oil and natural gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (the "**MBOGA**"), *The Oil and Gas Production Tax Act* and related regulations and guidelines.

Liability Management Rating Program

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**"). 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 ("**LMR**").

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. The Orphan Fund was originally conceived to be bankrolled exclusively by licensees in the AB LLR Program and AB OWL Program who contribute to 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 payment 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 broad 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**"), and has issued a call for feedback on the Draft Directive that will be open until mid-February 2021. 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, our 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 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. We are participating in the voluntary ABC program.

British Columbia

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

In the spring of 2019, a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BC Commission to impose more than one levy in a given calendar year.

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

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund takes on the obligation of carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Ministry announced that it considers all licence transfer applications non-routine as it does not strictly rely on the standard LLR calculation in evaluating deposit requirements.

Manitoba

To date, the Government of Manitoba has not implemented a liability management rating program similar to those found in the other Western Canadian provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the *Drilling and Production Regulations*. The MBOGA also establishes the Abandonment Fund Reserve Account (the "**Abandonment Fund**"). The Abandonment Fund is a source of funds that may be used to operate or abandon a well or facility when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred, as well as annual levies for inactive wells and batteries.

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. The Government of British Columbia is disbursing its $120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program and the Legacy Sites Reclamation Program. In Saskatchewan, $400 million in federal funding will be allocated through the Accelerated Site Closure Program ("**ASCP**"). The first phase of the ASCP will make $100 million available to eligible service companies to conduct abandonment and reclamation work. Further tranches of the ASCP, up to $300 million, will be made available in the future.

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 our operations and funds 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. Specific details have not yet been announced.

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 November 2015, the Government of Alberta introduced a Climate Leadership Plan. 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 is currently $30/tonne of CO2e and will increase to $40/tonne 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* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of 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.

British Columbia

In August 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge is currently set at $40/tonne of CO2e. In response to COVID-19, the Government of British Columbia has delayed the scheduled increase to $45/tonne of CO2e until April 1, 2021.

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

In December 2018, the Government of British Columbia announced an updated clean energy plan, "**CleanBC**", which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of oil and natural gas production; (v) reducing 45% of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles.

In January 2019, the BC Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

Saskatchewan

In May 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The government subsequently released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* ("**Prairie Resilience**"), outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program.

On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to reduce 4.5 million tonnes of CO2e emissions by 2025, with a total reduction of 38.2 million tonnes of CO2e by 2030.

In April 2019, Saskatchewan produced its first annual report on climate resilience. The report measures the Province's progress on goals set out under *Prairie Resilience*. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

To facilitate its emissions reduction efforts, the Government of Saskatchewan has implemented *Directive PNG017: Measurement Requirements for Oil and Gas Operations*, which came into force in December 2019 and was amended in April 2020, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020. Together with the Saskatchewan O&G Emissions Regulations, these directives enable the Government of Saskatchewan to regulate emissions reductions within the province. In November 2020, the Government of Canada and the Government of Saskatchewan announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Saskatchewan.

Manitoba

In 2018, the Government of Manitoba unveiled the *Climate and Green Plan Implementation Act*. The Act included a new *Climate and Green Plan Act*, a new *Industrial Greenhouse-Gas Emissions Control and Reporting Act* and various related amendments to existing legislation. In March 2020, the Government of Manitoba introduced the *Climate and Green Plan Implementation Act, 2020*, which, among other things, introduced a $25/tonne of CO2e charge.

The original *Climate and Green Plan Implementation Act* also required the Government of Manitoba to establish five-year emissions reduction targets. In June 2019, the Government of Manitoba announced a GHG emissions reduction target of one megatonne for the 2018-2022 period.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the *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 Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In 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.

Accountability and Transparency

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

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in our 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 our business and the oil and natural gas business generally.

Exploration, Development and Production Risks

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

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 our business, financial condition, results of operations and prospects.

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

Weakness and Volatility in the Oil and Natural Gas Industry

Market events and conditions, including global excess oil and natural gas supply, the ongoing coronavirus disease ("**COVID-19**") pandemic, actions taken by OPEC, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakened global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including a growing anti-hydrocarbon sentiment, have caused significant volatility in commodity prices. See "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Impact of Pandemics*". 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 "*Risk Factors – Royalties and Incentives*", "*Risk Factors – Regulatory Authorities and Environmental Regulation*" and "*Risk Factors – 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 our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict our funds flow resulting in less funds from operations being available to fund our capital expenditure budget. Consequently, we may not be able to replace our production with additional reserves and both our 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 the value of our economically recoverable reserves, lower commodity prices may also result in a decrease in the value of our infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of our oil and natural gas assets on our balance sheet and the recognition of an impairment charge in our income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms. See "*Risk Factors – Additional Funding Requirements*".

Impacts of Pandemics

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 our 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 our results, business, financial condition or liquidity, for a substantial period of time.

Our 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 and/or decline in commodity prices as a result of:

- the shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruption or labour shortages caused by workers becoming infected with COVID-19, or government or health authority mandated restrictions on travel by workers or closure of facilities or worksites;
- suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations;
- reduced cash flows resulting in less funds from operations being available to fund capital expenditure budgets;
- reduced commodity prices resulting in a reduction in the volumes and value of reserves;
- crude oil storage constraints resulting in the curtailment or shutting in of production;
- counterparties being unable to fulfill their contractual obligations on a timely basis or at all;
- the inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate; and
- the ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

The COVID-19 pandemic has also created additional operational risks for us, including the need to provide enhanced safety measures for our 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 our systems, networks, and data as a larger number of our employees work remotely. We are 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 our 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 our 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.

Prices, Markets and Marketing

Our ability to market our oil and natural gas may depend upon our 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 our control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by us, including:

- deliverability uncertainties related to the distance our 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 our ability to access such markets. A material decline in prices could result in a reduction of our 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 our reserves. We 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 carrying value of our reserves, borrowing capacity, revenues, profitability and funds from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

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

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

Market Price

The trading price of our Common Shares is subject to substantial volatility often based on factors related and unrelated to our financial performance or prospects. Factors unrelated to our 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 our Common Shares has been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

Dividends

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

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider 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 our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. 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 we can focus our efforts and resources more efficiently. Depending on the market conditions for such non core assets, certain of our non core assets may realize less on disposition than their carrying value on our consolidated financial statements.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. 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 USMCA which replaced NAFTA was ratified on July 1, 2020 and may impact our 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 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 us.

In addition to the changing political landscape in the United States, the impact of the United Kingdom's exit from the European Union are slowly emerging and some impacts may not become apparent for some time. 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 our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our 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 – British Columbia*".

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

Operational Dependence

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

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

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Our ability to execute projects and to market oil and natural gas depends upon numerous factors beyond our 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 our 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, we could be unable to execute projects on time, on budget, or at all.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the 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 our inability to realize the full economic potential of our products or in a reduction of the price offered for our 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 our production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. 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 XL 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 us.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do 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 our ability to process our 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 petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than ours. 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 us. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our 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 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 we will be able to respond to such competitive pressures and implement such technologies on a timely basis, or at an acceptable cost. If we do implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. If we are unable to utilize the most advanced commercially available technology, or are unsuccessful in implementing certain technologies, our business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and 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. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and funds flow by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Regulatory

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 our costs, either of which may have a material adverse effect on our 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 Regulation*", "*Industry Conditions – Curtailment" and "Risk Factors – Liability Management*".

In order to conduct oil and natural gas operations, we 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 we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect our business, financial condition and the market value of our Common Shares or our 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

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

Hydraulic Fracturing

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 our 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 we are ultimately able to produce from our reserves.

Alberta

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

British Columbia

Due to seismic activity recorded in the Kiskatinaw Area, in May 2018, the BC Commission requirements including, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BC Commission and the suspension of operations if a seismic event above a 3.0 magnitude occurs.

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Corporation's business operations, financial condition, results of operations and prospects. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. These requirements are outlined in provincial legislation, namely the *Water Sustainability Act* and the *Dam Safety Regulation*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. The BC Commission has issued compliance orders with respect to individual dams, but it remains uncertain how, and to what extent the relevant industry regulators will respond to this issue. We may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where we are not strictly complying with the current regulatory framework.

Availability of CO_2

We are reliant upon certain key suppliers for CO_2 used in our enhanced oil recovery processes and no assurances can be given that we will not experience delays or other difficulties in obtaining CO_2. Currently, two suppliers provide all of our CO_2 purchases used in our operations, with the contracts expiring in April of 2024 and December of 2027. Although we have our required CO_2 supplies under contract for a number of years, if thereafter they are not renewed or if there is a default or force majeure and current suppliers are unable to provide the CO_s or otherwise fail to timely deliver the product in the quantities required, any resulting delays in our operations could have a material adverse effect on our results of operations and our financial condition.

Environmental

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

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are 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 our business, financial condition, results of operations and prospects.

Liability Management

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 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 AB LMF. Other changes to the requirements of liability management programs, may result in significant increases to our compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. 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 in the working interest partners of the defunct licensee and may order the AER 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 our 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

Chronic Climate Change Risks

Our exploration and production facilities and other operations and activities emit GHGs which may require us to comply with federal and/or provincial GHG 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 our effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our 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. 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 us to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to our premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, we 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 hydrocarbons which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the hydrocarbon 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 our operating expenses, and, in the long-term, potentially reducing the demand for oil and natural gas production, resulting in a decrease in our profitability and a reduction in the value of our assets or requiring asset impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations*", "*Risk Factors – Reputational Risk Associated with our 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 our ability to access our properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located in locations that are proximate to forests, grasslands or 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 our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

Variations in Foreign Exchange Rates and Interest Rates

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 our production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of our 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 we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results.

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

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

Substantial Capital Requirements

We anticipate 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 funds from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our 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 our securities in particular.

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

Further, if our revenues or reserves decline, we 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 us, 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 us. We may be required to seek additional equity financing on terms that are highly dilutive to existing Shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our funds flow from our reserves may not be sufficient to fund our ongoing activities at all times and, from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, we 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, we 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 us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our 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 our capital expenditure plans may result in a delay in development or production on our properties.

Credit Facility Arrangements

We are required to comply with covenants under our Credit Facility and Senior Secured Notes which include certain financial ratio tests, which, from time to time, either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under our Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our Credit Facility and Senior Secured Notes may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

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

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

Issuance of Debt

From time to time, we 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 our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect us from commodity price declines, we 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, our hedging arrangements may expose us 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, we 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, we will not benefit from the fluctuating exchange rate.

Availability and Cost of Material and Equipment

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 our exploration, development and operating activities.

Title to and Right to Produce from Assets

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

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

Reserves Estimates

There are numerous uncertainties inherent in estimating reserves and the future net revenues attributed to such reserves. The reserves and associated net revenue information set forth in this Annual Information Form 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 revenues 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. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates and such variations could be material.

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

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net revenues as summarized herein. Actual future net revenues 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 net revenues derived from our 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 we intend to undertake in future years. The reserves and estimated net revenues 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 our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blowouts, leaks of sour gas, property damage, personal injury or other hazards. Although we maintain 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, we 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 us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Non-Governmental Organizations

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

Dilution

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

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we, 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 our 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 our business, financial condition, results of operations and prospects.

Litigation

In the normal course of our operations, we 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 us and could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail 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 our financial condition.

Indigenous Claims

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our 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 our business and financial results.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our 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 us at competitive risk and may cause significant damage to our business. The harm to our 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, we 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 our business that such a breach of confidentiality may cause.

Income Taxes

We file all required income tax returns and believe that we are 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 us, 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 us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In addition, we may be exposed to third party credit risk from operators of properties in which we have a working or royalty interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry, generally, and of our joint venture partners may affect a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find 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 us being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Conflicts of Interest

Certain of our directors or officers 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 us to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Reliance on a Skilled Workforce and Key Personnel

Our operations and management 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 our business plans which could have a material adverse effect on our 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 we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. We do not have any key personnel insurance in effect. Contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, certain of our current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Information Technology Systems and Cyber-Security

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

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our 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 our competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If we become a victim to a cyber phishing attack it could result in a loss or theft of our financial resources or critical data and information, or could result in a loss of control of our technological infrastructure or financial resources. Our 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 our 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 our risk of cyber-attacks, as increased malicious activities are creating more threats of cyber attacks 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.

We maintain policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber-security risk assessments. We also employ encryption protection of our confidential information, all computers and other electronic devices. Despite our efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage our information technology infrastructure. We apply technical and process controls in line with industry-accepted standards to protect our 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 our performance and earnings, as well as our reputation, and any damages sustained may not be adequately covered by our 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 our business, financial condition and results of operations.

Social Media

We face 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 our systems and obtain confidential information. Although we have a social media policy, we do not restrict the social media access of our employees. 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 we 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.

Disposal of Fluids Used in Operations

Regulations regarding the disposal of fluids used in our operations may increase our costs of compliance or subject it to regulatory penalties or litigation.

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

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas, our operating expenses and may impair our 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 our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with our counterparts who operate in jurisdictions where there are less costly carbon regulations.

Reputational Risk Associated with Our Operations

Our business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards us or as a result of any negative sentiment toward, or in respect of, our 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 we operate 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. Our 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 we have no control. Similarly, our reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by our operations. In addition, if we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultants to operate our business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and hydrocarbon companies may impact our 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 our reputation. Damage to our reputation could result in negative investor sentiment towards us, which may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares.

Changing Investor Sentiment

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 our Board of Directors, management and employees.

Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in us, or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares even if our 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 our assets which may result in an impairment change.

Expansion into New Activities

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

Forward-Looking Information

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

Additional information on the risks, assumption and uncertainties are found under the heading "*Notice to Reader – Special Note Regarding Forward-Looking Statements*" of this Annual Information Form.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within the most recently completed financial year, or before the most recently completed financial year but which is still material and is in effect, are the:

- Amended and Restated Credit Agreement dated April 27, 2018, as amended on December 11, 2018, May 28, 2019, June 30, 2020 and as increased pursuant to its terms by a Commitment Increase Acknowledgment and Confirmation Agreement dated February 24th, 2021 as increased pursuant to its terms by a Commitment Increase Acknowledgment and Confirmation Agreement dated February 24, 2021;

- Note Purchase and Private Shelf Agreement dated as of January 5, 2017, as amended on May 31, 2017, December 20, 2017, April 27, 2018, December 12, 2018 and May 28, 2019 in respect of the 3.46% Notes;

- Note Purchase Agreement dated as of May 31, 2017, as amended on December 20, 2017, April 27, 2018, December 12, 2018 and May 28, 2019 in respect of the 3.54% Notes;

- Note Purchase Agreement dated as of December 20, 2017, as amended on April 27, 2018, December 12, 2018 and May 28, 2019 in respect of the 3.90% Notes;

- Investor Rights Agreement dated as of January 4, 2021; and

- Registration Rights Agreement dated as of January 4, 2021.

The above listed agreements are available on our SEDAR profile at www.sedar.com. See "*Description of our Capital Structure – Credit Facility*", "*Description of our Capital Structure – Senior Secured Notes*" and "*General Development of Our Business – History and Development – Recent Developments – NAL Transaction*".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were a party to, or that any of our property is or was the subject of, during our most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a security regulatory authority during the most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

TRANSFER AGENT AND REGISTRAR

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of our directors and senior officers, or any holder of our Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of our outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction completed within the last three years or in any proposed transaction during the current financial year which have materially affected or are reasonably expected to materially affect us.

INTERESTS OF EXPERTS

We used PricewaterhouseCoopers LLP for external audit and tax advisory services for the fiscal year ended December 31, 2020. PricewaterhouseCoopers LLP has advised us that they are independent with respect to us within the meaning of the Rules of Professional Conduct of Chartered Professional Accountants of Alberta.

McDaniel prepared the McDaniel Report and the McDaniel NAL Report, a summary of which is contained in this Annual Information Form. None of the designated professionals of McDaniel have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statements, reports or valuations prepared by it, at any time thereafter or to be received by them.

Sproule prepared the Sproule Report, a summary of which is contained in this Annual Information Form. None of the designated professionals of Sproule have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statements, reports or valuations prepared by it, at any time thereafter or to be received by them.

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 us or of any of our associates or affiliates, except for Grant A. Zawalsky, one of our directors, is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at *www.sedar.com* and on our website at www.wcap.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our proxy materials relating to our annual and special shareholders meeting to be held on April 21, 2021. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2020 and the related management's discussion and analysis.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Whitecap Resources Inc.
Suite 3800, 525 – 8 Avenue S.W.
Calgary, Alberta, T2P 1G1
Tel: (403) 266-0767
Fax: (403) 266-6975

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Form 51-101F3

Management of Whitecap Resources Inc. ("**Whitecap**") is responsible for the preparation and disclosure of information with respect to Whitecap's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data.

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

The Reserves Committee of the Board of Directors of Whitecap has:

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

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

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

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

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

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

(c) the content and filing of this report.

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

(signed) "*Grant B. Fagerheim*"
Grant B. Fagerheim
President and Chief Executive Officer

(signed) "*Glenn A. McNamara*"
Glenn A. McNamara
Director, Chair of the Reserves Committee and Member of the Corporate Governance & Compensation Committee

(signed) "*Darin R. Dunlop*"
Darin R. Dunlop
Vice President Engineering

(signed) "*Gregory S. Fletcher*"
Gregory S, Fletcher
Director and Member of the Audit Committee and the Reserves Committee

February 24, 2021

APPENDIX B

MCDANIEL & ASSOCIATES CONSULTANTS LTD.
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Form 51-101F2

To the board of directors of Whitecap Resources 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:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $000s)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves (County or Foreign Geographic Area)**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	December 31, 2020	Canada	-	4,008,149	-	4,008,149

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.
8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, February 11, 2021.

"ORIGINALLY SIGNED BY"

Brian R. Hamm, P. Eng.
President & CEO

APPENDIX C

WHITECAP RESOURCES INC.
MANDATE & TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Whitecap Resources Inc. ("**Whitecap**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

1. to assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Whitecap and related matters;

2. to provide good communication between directors and external auditors;

3. to enhance the external auditor's independence;

4. to review the credibility and objectivity of financial reports; and

5. to strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of the Committee

1. The Committee shall be comprised of at least three (3) directors of Whitecap, none of whom are members of management of Whitecap and all of whom are "independent" (as such term is used in National Instrument 52 110 Audit Committees ("**NI 52 110**").

2. The Board shall appoint the Committee Chair, who shall be an independent director, and other members of the Committee.

3. All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in NI 52 110.

4. Any members of the Committee may be removed or replaced at any time by the Board and shall 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 shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains.

Mandate and Responsibilities of the Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to Whitecap's Internal Control Systems, including:

    - identifying, monitoring and mitigating business risks; and

- ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the annual and interim financial statements of Whitecap and the notes thereto prior to their submission to the Board for approval. The process should include but not be limited to:

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

   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation and reserves with respect to environmental matters;

   - reviewing non-recurring transactions and accounting treatment of unusual or non recurring transactions;

   - ascertaining compliance with covenants under loan agreements;

   - reviewing disclosure requirements for commitments and contingencies;

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

   - reviewing unresolved differences between management and the external auditors; and

   - obtaining explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, management discussion and analysis ("**MD&A**"), annual information forms ("**AIF**"), business acquisition reports, annual reports and all public disclosure containing audited or unaudited financial information before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Whitecap's disclosure of all other financial information and shall periodically assess the accuracy of those procedures. The Committee shall also review Whitecap's policies and procedures for making and updating disclosures on Whitecap's website and shall periodically assess the adequacy and accuracy of such policies and procedures.

5. With respect to the appointment of external auditors by the board, the Committee shall:

   - ensure the auditor's ultimate accountability to the Board and the Committee as representatives of the shareholders and as such representatives, to evaluate the performance of the auditor;

   - recommend to the Board the appointment of the external auditors;

   - 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 shall report directly to the Committee;

   - 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;

   - review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors;

   - ensure that the auditor submits on a periodic basis to the Committee, a formal written statement delineating all relationships between the auditor and Whitecap, consistent with Canadian and other applicable auditor independence standards, and to review such statement and to actively engage in a dialogue with the auditor with respect to any undisclosed relationships or services that may impact on the objectivity and independence of the auditor, and to review the statement and dialogue with the Board and recommend to the Board appropriate action to ensure the independence of the auditor;

- provide a line of communication between the auditors and the Board; and

- meet with the auditors at least once per quarter without management present to allow a candid discussion regarding any concerns the auditors may have and to resolve any disagreements between the auditor and management regarding Whitecap's financial reporting.

6. Review with external auditors (and internal auditor if one is appointed by Whitecap) their assessment of the internal controls of Whitecap, their written reports containing recommendations for improvement, and management's response and follow up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Whitecap and its subsidiaries.

7. The Committee must pre approve all non-audit services to be provided to Whitecap or its subsidiaries by the external auditors. The Committee may delegate to one or more 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.

8. The Committee shall review Whitecap's enterprise risk management system including risk management policies and procedures (i.e. hedging, litigation, climate change and insurance) and report to the Board with respect to risk assessment process and the appropriateness of risk management policies and procedures in managing risk.

9. The Committee shall establish a procedure for:

   - the receipt, retention and treatment of complaints received by Whitecap regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of Whitecap of concerns regarding questionable accounting or auditing matters.

10. The Committee shall review and approve Whitecap's hiring policies regarding employees and former employees of the present and former external auditors of Whitecap.

11. The Committee shall have the authority to investigate any financial activity of Whitecap. All employees of Whitecap are to cooperate as requested by the Committee.

12. The Committee shall review all related party transactions (as defined by applicable regulations) and ensure the nature and extent of such transactions are properly disclosed.

13. The Committee shall review the status of taxation matters of Whitecap and its major subsidiaries.

14. The Committee shall review the short term investment strategies respecting the cash balance of Whitecap.

15. The Committee shall conduct or undertake such other duties as may be required from time to time by any applicable regulatory authorities, including the TSX.

16. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Whitecap without any further approval of the board.

Meetings and Administrative Matters

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

2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present the Chair for purposes of the meeting.

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

4. Meetings of the Committee should be scheduled to take place at least four times per year and at such other times as the Chair of the Committee shall determine. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

5. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair. The Committee may invite such other officers, directors and employees of Whitecap as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee.

6. Minutes of all meetings of the Committee shall be taken and shall be made available to the Board. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.

7. The Committee shall meet with the external auditors at least quarterly (including without management present) and at such other times as the external auditors and the Committee consider appropriate.

8. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of Whitecap without any further approval of the Board.

9. The auditors of Whitecap are entitled to receive notice of every meeting of the Committee and be heard thereat.

10. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chair of the Board by the Chair of the Committee.

Approved by the Board of Directors on October 27, 2020.

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