ANNUAL INFORMATION FORM
DATED FEBRUARY 21, 2023

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 gas assets in Western Canada. The primary areas of focus of our development programs are in Northern Alberta and British Columbia, Central Alberta, and 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 acquisitions and organic growth on existing and acquired assets.

WHAT'S INSIDE

GLOSSARY OF TERMS

Entities and Transactions

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

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

Highrock means Highrock Resources Ltd.

Hyak means Hyak Energy ULC.

Kicking Horse means Kicking Horse Oil & Gas Ltd.

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.

Quantum means Quantum Oil & Gas Investments Inc.

Shareholders means holders of our Common Shares.

Spitfire means Spitfire Energy Inc.

TimberRock means TimberRock Energy Corp.

TimberRock ULC means Azimuth-TimberRock Investment ULC.

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.

XTO Transaction means the Corporation's strategic acquisition of XTO Energy Canada ULC (subsequently renamed Whitecap Energy Canada ULC) and XTO Energy Canada (subsequently renamed Whitecap Energy Canada) completed on August 31, 2022, for total cash consideration of approximately $1.9 billion.

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 9, 2023, evaluating the crude oil, natural gas, NGLs and sulphur reserves attributable to all of our oil and natural gas assets as at December 31, 2022.

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

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*".

Preferred Shares means our preferred shares, as presently constituted.

Senior Secured Notes means, collectively, our 3.54% Notes and 3.90% Notes as more particularly described (and defined) under the heading "*Description of our Capital Structure – Senior Secured Notes*".

Term Loan means the $705 million 4-year term loan we obtained in conjunction with the closing of the XTO Transaction as more particularly described under the heading "*Description of our Capital Structure – Term Loan*".

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
CO_2	carbon dioxide
GHGs	greenhouse gases
MMBoe	million barrels of oil equivalent
Scope 1 emissions	direct emissions from owned or controlled sources
Scope 2 emissions	indirect emissions from the generation of purchased energy
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 of 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 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: "*Who We Are*", "*General Development of Our Business – History and Development*" and "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our focus, business plan and strategy, including regarding the future payment of dividends; "*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 environmental, health, safety and social policies and plans, our competitive position within the oil and gas industry not being affected by changes in applicable legislation, the focus of our environmental management programs and operating guidelines, expectations regarding future abandonment and reclamation costs and expenditures and that the Corporation is in compliance with all existing environmental standards and regulations and includes sufficient amounts in its capital expenditure budget to continue to meet current environmental protection requirements; "*General Development of Our Business – History and Development*" with respect to details of the Corporation's 2023 capital program, normal course issuer bid and emissions reduction targets; "*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 2023; "*General Development of Our Business – Competitive Conditions*" as to our aim to remain competitive by maintaining financial flexibility and utilizing current technologies to enhance optimization, development and operational activities; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Reserves Data (Forecast Prices and Costs)*" as to our reserves, future net revenue from our reserves and future income taxes; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Pricing Assumptions*" as to our expectations regarding future 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 (including timing thereof) of our proved undeveloped reserves and probable undeveloped reserves, our expectation that no significant factors or significant uncertainties will affect any particular components of our reserves data other than the factors disclosed under this heading, abandonment and reclamation costs and obligations, future developments costs, our plans to fund future development costs through a combination of cash from operating activities and debt, and our anticipated funding costs; "*General Description of Our Business – Other Oil and Natural Gas Information – Forward Contracts*" with respect to the Corporation's forward contracts; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to the decline rates, future production, reserves, economics, inventories, growth and other opportunities, working interest consolidation potential, asset enhancement plans, expansion opportunities, drilling, development, completion, waterflood and other optimization plans, capital requirements, CO_2 enhanced oil recovery and sequestration plans and the results therefrom relating to our principal properties, future land expiries and our ability to extend same, 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 and production for 2023; 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:

- projections of market prices and costs, and exchange and inflation rates;
- expectations regarding future supply of and demand for oil and gas;
- 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;
- government programs, incentives, pledges, investments and potential effects thereof;
- our commitment to reporting on sustainability performance; 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;
- operational risks and liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- impacts of pandemics;
- our ability to market our oil and natural gas;
- market prices of oil and natural gas and differentials;
- stock market volatility;
- our ability to pay dividends and our dividend policy;
- the Corporation's ability to access sufficient capital from internal and external sources;
- incorrect assessments of the value of acquisitions;
- political or economic developments;
- changes in general economic, market and business conditions;
- operational dependence on others and third party risks;
- project risks;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- costs of new technologies;
- fluctuation in the supply and demand for oil and natural gas;
- uncertainties and changes in royalty regimes and other regulatory changes;
- risks associated with hydraulic fracturing and waterflooding;
- water and carbon dioxide supplies;
- environmental and climate change risks;
- inflation and cost management;
- fluctuation in foreign exchange and interest rates;
- access to capital and fluctuations in the costs of borrowing;
- the impact of our risk management activities;
- our title to and rights to produce from our assets;
- 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;
- availability and costs of insurance;
- 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;
- information technology and cyber-security issues;
- the impact of negative government, institutional, public and/or investor sentiment in respect of the oil and gas industry and the use of fossil fuels; 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; availability of skilled labour; timing and amount of capital expenditures; future exchange rates, interest rates and inflation 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 (if any), 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.

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 ABCA 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 with its wholly-owned subsidiary, Cashel Resources Inc., pursuant to the ABCA 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 ABCA to form Spitfire.

We were incorporated under the ABCA 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 director 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.

On April 21, 2021, we filed articles of amendment to amend our Preferred Shares to change the rights, privileges, restrictions and conditions in respect of our Preferred Shares. The amendment was approved by our Shareholders at our annual and special meeting held on April 21, 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 on the corresponding dates set forth below:

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
January 4, 2021	NAL
February 24, 2021	TORC
May 14, 2021	Quantum
July 2, 2021	Highrock
January 10, 2022	TimberRock and TimberRock ULC
January 1, 2023	1874946 Alberta Ltd.

Whitecap has no material subsidiaries other than Whitecap Energy Canada ULC (which was incorporated under the ABCA) and Whitecap Energy Canada (a general partnership formed under the *Partnership Act* (Alberta)), both of which are wholly-owned by Whitecap. 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 2020

On January 15, 2020, we completed the acquisition of all of the issued and outstanding shares of Hyak 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 annualized) 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. The normal course issuer bid terminated on May 20, 2021. We purchased and cancelled a total of 2,501,800 Common Shares pursuant to the bid.

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

Developments in 2021

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.

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 joined our Board.

Concurrent with the closing of the TORC Transaction our Credit Facility was increased by $230 million to $1.405 billion from $1.175 billion.

In connection with the TORC Transaction, we increased our monthly dividend from $0.01425 per Common Share to $0.01508 per Common Share ($0.18096 per Common Share annualized). The dividend increase was effective with the March 2021 dividend payable in April 2021.

Effective as of March 26, 2021, we amended our Credit Facility to, among other things, extend our Credit Facility maturity to May 31, 2025.

On May 14, 2021, we completed the indirect acquisition of Kicking Horse, a privately held subsidiary of Quantum, for approximately 34.5 million Common Shares and $56.2 million in cash. As part of the transaction, Kicking Horse was amalgamated into Quantum and Quantum was amalgamated into us.

On May 17, 2021, we announced that our monthly dividend would be increased from $0.01508 to $0.01625 per Common Share ($0.195 per Common Share annualized) effective with the June 2021 dividend payable in July.

On May 21, 2021, we commenced a normal course issuer bid to purchase, from time to time, up to 29,894,096 Common Shares on the open market through the facilities of the Toronto Stock Exchange and/or other Canadian exchanges. In March 2022, we amended the bid to increase the number of Common Shares that we could purchase for cancellation thereunder to 58,947,076 Common Shares. The normal course issuer bid terminated on May 20, 2022. We purchased and cancelled a total of 33,326,223 Common Shares pursuant to the bid.

On July 28, 2021, we published and posted to our website our 2021 environmental, social and governance report (the "**2021 ESG Report**") which contained an increased direct emissions intensity reduction target of 30% by 2023 from 2019 levels (previously a 20% target). New to the 2021 ESG Report was a third-party limited assurance of select emissions metrics conducted by an independent firm.

On July 2, 2021, we completed the acquisition of Highrock, a private company, for approximately 3.6 million Common Shares and $44.4 million in cash. Following completion of the transaction, Highrock was amalgamated into us.

On October 14, 2021, we announced that our monthly dividend would be increased from $0.01625 per Common Share to $0.0225 ($0.195 per Common Share annualized)per Common Share beginning with the October dividend payable in November 2021.

In October 2021, our Board of Directors approved our 2022 capital program of $470 to $490 million, which was increased by $40 million in December 2021 to $510 to $530 million.

Effective as of October 27, 2021, we amended our Credit Facility to, among other things, extend our Credit Facility maturity to May 31, 2026 and to increase the revolving syndicated facility by $200 million to $1.53 billion. The Credit Facility is more particularly described under the heading "*Description of our Capital Structure – Credit Facility*".

On October 31, 2021, we completed the sale of a newly formed 5% gross overriding royalty on our working interest in the Weyburn CO_2 unit for cash proceeds of $188 million to Topaz Energy Corp.

On December 1, 2021, we acquired certain assets in the Weir Hill area for approximately 2.7 million Common Shares and $20.8 million of cash.

Developments in 2022

On January 5, 2022, we repaid $200 million in senior secured notes that had an annual coupon rate of 3.46%. The Senior Secured Notes that remain outstanding are more particularly described under the heading "*Description of our Capital Structure – Senior Secured Notes*".

On January 10, 2022, we completed the acquisition of TimberRock and TimberRock ULC for approximately $205.8 million in cash, 10.4 million Common Shares and 2.1 million contingent equity rights entitling the holders thereof to acquire up to 2.1 million Common Shares, subject to post-closing adjustments, and dividend equivalent payments. As part of the transaction, TimberRock and TimberRock ULC were amalgamated into us. In April 2022, we issued 1.97 million Common Shares to settle the contingent equity rights.

In February 2022, our Board approved an increase to our monthly dividend from $0.0225 per Common Share to $0.03 per Common Share ($0.36 per Common Share annualized) beginning with the March dividend payable in April 2022.

In February 2022, we announced that we are transitioning to a Sustainability Linked Loan ("**SLL**") on our Credit Facility that includes pricing adjustments related to two key emission reduction performance targets. Our key performance indicators for the SLL are a 15% reduction to our combined intensity of Scope 1 emissions and Scope 2 emissions by 2025, and a 30% reduction to our methane emissions intensity by 2025, in each case utilizing 2020 emissions intensity as the baseline. See "*Description of our Capital Structure – Credit Facility*".

On May 18, 2022, Ms. Chandra Henry was elected to our Board of Directors and Ms. Heather Culbert retired from our Board of Directors.

On May 21, 2022, we commenced a normal course issuer bid to purchase, from time to time, up to 58,341,984 Common Shares on the open market through the facilities of the Toronto Stock Exchange and/or other Canadian exchanges. The normal course issuer bid will terminate on May 20, 2023. As at the date of this Annual Information Form, we have purchased and cancelled a total of 14,461,100 Common Shares pursuant to the bid.

In June 2022, concurrent with the announcement of the XTO Transaction, our Board approved (i) an increase to our monthly dividend from $0.03 per Common Share to $0.0367 per Common Share ($0.4404 per Common Share annualized) beginning with the July dividend payable in August 2022, and (ii) an increase to our 2022 capital program to $610 to $630 million.

On August 31, 2022, we completed the acquisition of XTO Energy Canada and XTO Energy Canada ULC for total cash consideration of approximately $1.9 billion. Further particulars with respect to the XTO Transaction are set forth in our material change report dated July 8, 2022, which is filed on our SEDAR profile at *www.sedar.com.* The assets acquired by us pursuant to the XTO Transaction consisted primarily of tight oil/condensates and shale gas assets located in Northwest Alberta. In conjunction with closing of the XTO Transaction (i) we also closed the issuance of a $705 million 4-year Term Loan and increased our Credit Facility by $395 million (see "*Description of our Capital Structure*" for details), (ii) our Board of Directors approved an increase to our 2022 capital program by $60 million to $670 to $690 million, and (iii) XTO Energy Canada ULC was renamed "Whitecap Energy Canada ULC" and XTO Energy Canada was renamed "Whitecap Energy Canada".

In September 2022, our Board of Directors approved our 2023 capital program of $900 to $950 million.

On November 25, 2022, we published and posted to our website our 2022 environmental, social and governance snapshot report (the "**2022 ESG Report**"). The 2022 ESG Report confirmed that in connection with transitioning to a sustainability linked loan under our Credit Facility in early 2022, we are now targeting to reduce our methane emissions intensity by 30% by 2025 from 2020 levels and our combined intensity of Scope 1 emissions and Scope 2 emissions by 15% by 2025 from 2020 levels. The 2022 ESG Report contains a third-party limited assurance of select GHG emissions figures for the year ended December 31, 2021 conducted by an independent firm.

Recent Developments

In January and February 2023, we completed the disposition of certain non-strategic assets, effective October 1, 2022, for aggregate consideration (after closing adjustments) of $390 million, consisting of $364 million in cash and producing assets that consolidate our working interest in our operated Butte, Saskatchewan core area. In connection with the disposition, we increased our monthly dividend from $0.0367 per Common Share to $0.0483 per Common Share ($0.5796 per Common Share annualized). The dividend increase was effective with the January dividend payable in February 2023.

Significant Acquisitions

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

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 Northern Alberta and British Columbia, Central Alberta and 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 sustainable monthly dividends and per share growth through a combination of accretive acquisitions and organic growth on existing and acquired assets.

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

- provide dividends and targeted per share growth in production, reserves and cash flow from operating activities;
- 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*" and "*Risk Factors – Derivative Risk Management Contracts*".

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 and 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 Environment 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 2022, expenditures for normal compliance with environmental regulations as well as expenditures for above normal compliance were not material.

In 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.

As noted above under "*History and Development – Developments in 2022*", in February 2022, we transitioned to a SLL on our Credit Facility that includes pricing adjustments related to two key emission reduction performance targets. The SLL has a cumulative pricing adjustment of 5 basis points to the applicable margin, as well as a pricing adjustment of up to 1 basis point to the standby fee, that can result in price increases or decreases depending on performance. Our key performance indicators for the SLL are a 15% reduction to our combined intensity of Scope 1 emissions and Scope 2 emissions by 2025, and a 30% reduction to our methane emissions intensity by 2025, in each case utilizing 2020 emissions intensity as the baseline. The SLL is a continuation of our commitment towards environment, social and governance best practices and by linking sustainability performance targets to our Credit Facility there is a direct financial benefit to meeting our emission reduction goals.

Annually, we disclose an environmental, social and governance ("**ESG**") report containing tables with performance data on material ESG topics. 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 reports include indices that link elements of these three standards to report contents, where applicable. Each of our 2020 ESG Report, 2021 ESG Report and 2022 ESG Report is available on our website at www.wcap.ca.

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 2023 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, equipment, supplies and staffing. See "*Risk Factors – Competition*", "*Risk Factors – Availability of CO_2*" and "*Risk Factors – Inflation and Cost Management*".

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

Human Resources

As at December 31, 2022, we employed 522 full-time employees, including 261 office and 261 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 9, 2023. The statement is effective as of December 31, 2022. 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, respectively, 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, 2022 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.

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

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, 2022 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)*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**gross**" means:

   (a) in relation to our interest in production and reserves, our 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 our interest in production and reserves, our 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**" 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 bitumen, coal bed methane, gas hydrates, heavy crude oil, synthetic crude oil or synthetic gas reserves as of December 31, 2022.

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, 2022 FORECAST PRICES AND COSTS					
	LIGHT AND MEDIUM CRUDE OIL		TIGHT CRUDE OIL		CONVENTIONAL NATURAL GAS (1)	
	GROSS (Mbbls)	NET (Mbbls)	GROSS (Mbbls)	NET (Mbbls)	GROSS (MMcf)	NET (MMcf)
PROVED:						
Developed Producing	219,929	187,142	321	249	374,933	339,527
Developed Non-Producing	2,937	2,559	727	597	6,046	5,366
Undeveloped	106,369	91,080	9,393	7,819	190,372	170,718
TOTAL PROVED	329,235	280,780	10,441	8,664	571,350	515,612
TOTAL PROBABLE	118,896	98,680	8,850	6,915	241,899	213,968
TOTAL PROVED PLUS PROBABLE	448,131	379,459	19,291	15,579	813,249	729,580

RESERVES CATEGORY	SHALE GAS (1)		NATURAL GAS LIQUIDS	
	GROSS (MMcf)	NET (MMcf)	GROSS (Mbbls)	NET (Mbbls)
PROVED:				
Developed Producing	266,241	239,307	49,063	40,031
Developed Non-Producing	47,926	43,321	4,097	3,355
Undeveloped	944,099	838,384	104,449	83,075
TOTAL PROVED	1,258,266	1,121,012	157,609	126,461
TOTAL PROBABLE	877,640	757,448	100,105	75,654
TOTAL PROVED PLUS PROBABLE	2,135,906	1,878,460	257,714	202,115

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	9,550,559	7,915,965	6,563,019	5,638,130	4,983,561	20.26
Developed Non-Producing	490,797	407,042	352,934	314,491	285,469	24.13
Undeveloped	9,962,369	6,727,724	4,813,157	3,584,229	2,746,694	13.75
TOTAL PROVED	20,003,726	15,050,732	11,729,110	9,536,850	8,015,724	17.03
TOTAL PROBABLE	14,061,108	7,967,298	5,239,451	3,753,689	2,845,266	15.27
TOTAL PROVED PLUS PROBABLE	34,064,833	23,018,029	16,968,561	13,290,538	10,860,990	16.45

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	7,905,346	6,720,314	5,625,098	4,863,564	4,320,883
Developed Non-Producing	371,429	306,342	264,648	235,118	212,864
Undeveloped	7,524,447	4,962,623	3,454,730	2,493,701	1,844,337
TOTAL PROVED	15,801,222	11,989,279	9,344,476	7,592,383	6,378,084
TOTAL PROBABLE	10,687,259	5,987,845	3,905,931	2,778,884	2,093,558
TOTAL PROVED PLUS PROBABLE	26,488,481	17,977,124	13,250,408	10,371,267	8,471,642

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2022 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE [(1)] ($000s)	ROYALTIES [(2)] ($000s)	OPERATING COSTS ($000s)	DEVELOP-MENT COSTS ($000s)	ABANDON-MENT AND RECLAMATI ON COSTS [(3)] ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
TOTAL PROVED	54,837,907	9,324,328	16,566,931	6,312,285	2,630,488	20,003,726	4,202,503	15,801,222
TOTAL PROVED PLUS PROBABLE	83,561,772	14,911,869	23,577,407	8,306,875	2,700,584	34,064,833	7,576,352	26,488,481

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 BY PRODUCT TYPE AS OF DECEMBER 31, 2022 FORECAST PRICES AND COSTS		
	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [(1)] ($/Bbl)	UNIT VALUE [(1)] ($/Mcf)
TOTAL PROVED:			
Light and Medium Crude Oil [(2)(3)]	7,126,221	25.43	-
Tight Crude Oil [(2)(3)]	206,673	23.85	-
Conventional Natural Gas [(3)]	525,969	-	3.08
Shale Gas	3,870,248	-	3.57
	11,729,110		
TOTAL PROVED PLUS PROBABLE			
Light and Medium Crude Oil [(2)(3)]	9,764,395	25.78	-
Tight Crude Oil [(2)(3)]	396,805	25.47	-
Conventional Natural Gas [(3)]	767,055	-	3.27
Shale Gas	6,040,306	-	3.33
	16,968,561		

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 primarily assume 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**") published by McDaniel, GLJ Ltd. and Sproule Associates Limited. The IQRE Average Forecast is dated January 1, 2023. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs.

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

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (1)

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS			
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)
Forecast									
2023	80.33	103.76	77.46	68.44	4.23	39.80	53.88	-	0.745
2024	78.50	97.74	78.65	69.36	4.40	39.14	52.67	2.3	0.765
2025	76.95	95.27	78.42	69.92	4.21	39.74	51.42	2.0	0.768
2026	77.61	95.58	80.94	72.42	4.27	39.86	51.61	2.0	0.772
2027	79.16	97.07	82.78	74.29	4.34	40.47	52.39	2.0	0.775
2028	80.74	99.01	84.92	76.43	4.43	41.28	53.44	2.0	0.775
2029	82.36	100.99	86.65	78.01	4.51	42.11	54.51	2.0	0.775
2030	84.00	103.01	88.38	79.57	4.60	42.95	55.60	2.0	0.775
2031	85.69	105.07	90.15	81.17	4.69	43.81	56.71	2.0	0.775
2032	87.40	106.69	92.08	82.97	4.79	44.47	57.56	2.0	0.775
2033	89.15	108.83	93.92	84.63	4.88	45.35	58.71	2.0	0.775
2034	90.93	111.00	95.80	86.32	4.98	46.26	59.88	2.0	0.775
2035	92.75	113.22	97.71	88.05	5.08	47.19	61.08	2.0	0.775
2036	94.61	115.49	99.67	89.81	5.18	48.13	62.30	2.0	0.775
2037	96.50	117.80	101.66	91.60	5.29	49.09	63.55	2.0	0.775
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.775

Notes:

(1) As at January 1, 2023.
(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, 2022, excluding price risk management activities, were $114.68/Bbl for light and medium crude oil, $114.79/Bbl for tight crude oil, $5.56/Mcf for conventional natural gas, $5.71/Mcf for shale gas and $55.30/Bbl for natural gas liquids.

Reserves Reconciliation

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE FORECAST PRICES AND COSTS						
	LIGHT AND MEDIUM CRUDE OIL			TIGHT CRUDE OIL		
	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)
December 31, 2021	341,788	124,228	466,016	10,490	8,796	19,286
Extensions & Improved Recovery [(1)]	12,696	3,082	15,779	-	-	-
Technical Revisions [(2)]	(2,319)	(9,517)	(11,836)	1,440	(82)	1,358
Discoveries	-	-	-	-	-	-
Acquisitions [(3)]	4,255	1,320	5,575	180	55	235
Dispositions	(560)	(666)	(1,226)	-	-	-
Economic Factors [(4)]	3,114	449	3,563	134	82	216
Production	(29,738)	-	(29,738)	(1,804)	-	(1,804)
December 31, 2022	329,235	118,896	448,131	10,441	8,850	19,291

	CONVENTIONAL NATURAL GAS [(5)]			SHALE GAS [(5)]		
	PROVED (MMcf)	PROBABLE (MMcf)	PROVED PLUS PROBABLE (MMcf)	PROVED (MMcf)	PROBABLE (MMcf)	PROVED PLUS PROBABLE (MMcf)
December 31, 2021	494,692	204,038	698,729	297,033	159,820	456,854
Extensions & Improved Recovery [(1)]	28,124	11,884	40,007	116,243	26,262	142,505
Technical Revisions [(2)]	(4,321)	(25,458)	(29,780)	(8,596)	(5,927)	(14,523)
Discoveries	-	-	-	-	-	-
Acquisitions [(3)]	105,172	49,446	154,618	877,640	696,708	1,574,348
Dispositions	(15)	(6)	(21)	-	-	-
Economic Factors [(4)]	12,345	1,995	14,341	4,269	777	5,046
Production	(64,646)	-	(64,646)	(28,323)	-	(28,323)
December 31, 2022	571,350	241,899	813,249	1,258,266	877,640	2,135,906

	NATURAL GAS LIQUIDS		
	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)
December 31, 2021	60,593	29,171	89,763
Extensions & Improved Recovery [(1)]	10,867	2,608	13,474
Technical Revisions [(2)]	(303)	(1,356)	(1,659)
Discoveries	-	-	-
Acquisitions [(3)]	91,069	69,525	160,594
Dispositions	(4)	(1)	(5)
Economic Factors [(4)]	1,053	159	1,212
Production	(5,665)	-	(5,665)
December 31, 2022	157,609	100,105	257,714

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, 2022 plus any production from the acquisition dates to December 31, 2022.
(4) The economic factors amount is the change in reserves due exclusively to a change in pricing.
(5) Includes solution gas volumes.

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 three most recent financial years.

TIMING OF INITIAL PROVED UNDEVELOPED RESERVES ASSIGNMENT
GROSS RESERVES FIRST ATTRIBUTED BY YEAR

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		TIGHT CRUDE OIL (Mbbls)		CONVENTIONAL NATURAL GAS (MMcf)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2020	12,795	104,049	9,353	9,353	8,952	129,880
2021	25,865	115,566	1,964	10,197	36,292	148,129
2022	8,981	106,369	-	9,393	66,728	190,371

	SHALE GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2020	34,755	34,755	2,315	11,201
2021	187,636	218,424	18,955	29,090
2022	783,046	944,099	81,545	104,449

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 409.5 MMboe of proved undeveloped reserves with $5,573.7 million of associated undiscounted capital as at December 31, 2022.

All of our proved undeveloped reserves are in our core areas where we are actively spending capital to develop those properties. As such, consistent with the guidance in the COGE Handbook, we expect that the large majority of our booked undeveloped projects will be completed within a five year time frame and that all of our currently booked undeveloped projects will be completed within a seven 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 three most recent financial years.

TIMING OF INITIAL PROBABLE UNDEVELOPED RESERVES ASSIGNMENT
GROSS RESERVES FIRST ATTRIBUTED BY YEAR

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		TIGHT CRUDE OIL (Mbbls)		CONVENTIONAL NATURAL GAS (MMcf)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2020	6,482	48,975	6,182	9,072	6,754	85,454
2021	18,605	60,514	(142)	8,711	20,734	100,742
2022	3,443	56,710	-	8,536	46,903	131,825

	SHALE GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2020	24,420	35,426	1,601	8,514
2021	109,137	143,728	11,499	19,768
2022	671,990	800,145	67,647	85,041

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 an 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 305.7 MMboe of probable undeveloped reserves with $1,990.6 million of associated undiscounted capital as at December 31, 2022.

All of our probable undeveloped reserves are in our core areas where we are actively spending capital to develop those properties. As such, consistent with the guidance in the COGE Handbook, we expect that the large majority of our booked undeveloped projects will be completed within a five year time frame and that all of our currently booked undeveloped projects will be completed within a seven 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, 2022, we had 15,301.6 net wells for which we expect to incur abandonment and reclamation costs. The McDaniel Report deducted $2,700.6 million (undiscounted) and $490.8 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)
2023	861,948	906,075
2024	1,163,850	1,213,938
2025	1,284,368	1,433,213
2026	1,132,419	1,274,585
2027	929,620	1,262,728
Remaining	940,081	2,216,336
Total (Undiscounted)	6,312,286	8,306,875

We expect to fund the development costs of our reserves through a combination of cash flow from operating activities and debt. There can be no guarantee that such cash 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 cash flow from operating activities.

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, 2022.

Northern Alberta and British Columbia Business Unit

Our Northern Alberta and British Columbia Business Unit is comprised of two regional assets: Smoky River and Peace River.

The properties in our Smoky River region include Elmworth, Kakwa, Karr, Kaybob, Simonette and Wapiti, which are all located in Northwest Alberta. The primary reservoirs being developed are the Cardium, Dunvegan, Duvernay and Montney resource plays, all of which are light sweet (39° - 42° API) oil or condensate-rich natural gas. This area utilizes pad-based horizontal drilling and multi-stage fracturing, including extended reach horizontals. The region is comprised of large-scale opportunities and significant inventory setting up Smoky River to provide material future organic growth.

The recent acquisition of XTO Energy Canada is a continuation of our long-term strategy of consolidating high quality assets in our core operating areas to enhance free funds flow and return of capital to Shareholders. The XTO Energy Canada assets contain a significant land position in the liquids-rich portion of the Alberta Montney along with the Duvernay at Kaybob. The Montney assets acquired complement our existing Montney assets at Kakwa and Karr and increase our working interest to 100% on certain lands in South Kakwa. Our total Montney position is now 638,000 net acres.

The properties in our Peace River region include Valhalla, our original asset area. It is underpinned by the conventional Montney light oil waterflood pool that continues to outperform our original reserves estimates. In addition, we are actively exploiting Valhalla's ideally situated infrastructure by expanding our presence in the area through the Charlie Lake and Montney oil and gas resource plays. Boundary Lake is located primarily in Northeast British Columbia on the Alberta/British Columbia border, just east of Fort St. John, and is characterized by low base declines, low sustaining capital and a predictable production base within an active waterflood. The key characteristics of this legacy oil pool are high operated working interest, and light 35° API oil. Asset enhancement is on-going with waterflood optimization initiatives and the optimal implementation of horizontal wells. Development and completion design reviews are continually ongoing to further unlock additional resource value.

Central Alberta Business Unit

Our Central Alberta Business Unit is comprised of two regional assets: Southwest Alberta and West Central Alberta.

Our Central Alberta Business Unit represents the bulk of our Cardium and liquids-rich Mannville assets, which are primarily focused in Kaybob, Pembina, Ferrier and Garrington. The key characteristics of these formations are light sweet 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 either formation which results in predictable declines and production profiles. Several of the legacy Cardium pools are under active waterflood which reduces pool declines and increases the percentage of recoverable oil in place. Performance of these waterfloods has been improving with optimization efforts.

Saskatchewan Business Unit

Our Saskatchewan Business Unit is comprised of four regional assets: West Central Saskatchewan, Southwest Saskatchewan, Southeast Saskatchewan and Weyburn.

Our West Central Saskatchewan region represents our Viking resource oil play. Focus areas are Kerrobert, Plenty, Dodsland, Lucky Hills, Whiteside and Elrose. The key characteristics of this play are light 38° - 40° API oil, predictable geology and production profiles, as well as consistent and repeatable economics. Lucky Hills and Whiteside are characterized by horizontal primary oil development wells with quick payouts and a high operating netback. The Eagle Lake property is characterized by 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 waterfloods to increase reserve recoveries. Kerrobert is analogous to Eagle Lake with reservoir properties conducive to successful waterflooding. The Kerrobert waterflood is in its infancy of development, relative to Eagle Lake, and as a result has significant upside related to reserve recovery and decline stabilization.

Our Southwest Saskatchewan region's assets are concentrated west of Swift Current, Saskatchewan and are characterized by predictable low base decline and medium crude oil (18 - 26° API) production. This asset was incorporated into our portfolio opportunistically as an acquisition in 2016 and continues to generate significant cash flow. Multiple active waterfloods, as well as three established alkaline, surfactant, and polymer ("**ASP**") floods, are sustaining the area with 92%

of production coming from enhanced recovery. Additional waterflood and ASP potential exists and will be part of our ongoing enhanced oil recovery ("**EOR**") development programs. The primary formations being targeted in the area are the Atlas, Success, Roseray and Shaunavon. New areas and pools within the existing Southwest Saskatchewan land base are continually being pursued. These properties had not seen significant development prior to us acquiring them, and we combine horizontal wells, multi-stage fracture technology, and conventional production and EOR optimization efforts to maximize production and oil recovery from these pools.

The Southeast Saskatchewan region was added to our portfolio through the acquisition of NAL and TORC. The acquired asset base is comprised of a diverse portfolio consisting of both conventional and unconventional light oil play types. The conventional Mississippian is characterized by 30° - 40° API oil, and low decline which generates significant free cash flow. Our properties target the Alida, Frobisher, Midale and Ratcliffe formations which provide evolving opportunities through multi-legged horizontal drilling and well re-entry techniques in areas with stacked flow units. Conventional wells have high deliverability supported by an active regional aquifer and provide robust economics with significant high-quality inventory. The historic conventional Midale play in Southeast Saskatchewan has evolved in more recent years through horizontal multi-stage fracture stimulation. Delineation drilling has transitioned the unconventional Midale play to a development focus in several key areas with predictable and repeatable results yielding competitive economics. The key characteristics of this play are 26°- 38° API oil, large quantities of original oil in place, and low recovery factor to date. The Midale formation has favorable reservoir characteristic for waterflooding, and several key unconventional pilots are being initiated across our asset base. Additional upside is expected with further play delineation. The Torquay/Three Forks land base is largely undeveloped but has been delineated and ready for full scale development. The play is characterized by 40° API oil, high netbacks, with well-defined resource mapping. Further value generation will come through infrastructure expansion, optimization of completion design, and drilling efficiencies.

The Weyburn property is located south of Weyburn, Saskatchewan. The primary reservoirs being developed are the Midale and Frobisher. We have a 65.3% operated working interest in the Weyburn Unit which primarily produces light oil. 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 EOR development commencing in 2000. Significant expansion opportunities remain to expand the Weyburn CO_2 flood and further mitigate a low 3-5% base decline rate in conjunction with a very low maintenance capital requirement.

Oil and Natural Gas Wells

The following table summarizes, as at December 31, 2022, 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	2,690	2,169.2	239	85.9	1,417	1,057.9	1,152	705.3
British Columbia	205	192.6	15	7.1	135	129.4	14	9.4
Manitoba	114	110.3	-	-	131	127.0	-	-
Saskatchewan	6,059	4,843.4	51	10.5	4,647	3,767.6	180	113.9
Total	9,068	7,315.7	305	103.6	6,330	5,081.8	1,346	828.7

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, 2022:

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES (1)(2)(3)	
	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	1,209,837	968,471	1,246,190	855,428	2,456,027	1,823,899
British Columbia	25,921	18,055	63,108	55,788	89,029	73,842
Saskatchewan	413,715	353,269	732,833	551,704	1,146,547	904,974
Manitoba	2,796	2,796	18,136	17,267	20,932	20,063
Total	1,652,269	1,342,591	2,060,267	1,480,187	3,712,535	2,822,778

Notes:

(1) Includes our interest in approximately 921,242 gross (750,140 net) acres of unproved property land holdings. See "*Properties with no Attributed Reserves*" below.

(2) Rights to explore, develop and exploit 371,460 gross (354,624 net) acres of our land holdings could expire by December 31, 2023 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, 2022:

	GROSS ACRES	NET ACRES
Alberta	206,805	167,767
British Columbia	145,646	118,153
Saskatchewan	565,995	461,423
Manitoba	2,796	2,796
Total	921,242	750,140

Note:

(1) Approximately 207,112 gross (197,725 net) acres of these land holdings could expire by December 31, 2023.

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 affecting 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, 2022. See also "*Risk Factors – Derivative Risk Management Contracts*".

Tax Horizon

Based on estimated 2023 cash flow from operating activities and capital expenditures, we currently expect to be cash taxable in 2023.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2022:

EXPENDITURE	YEAR ENDED DECEMBER 31, 2022 ($000s)
Property acquisition costs:	
Proved properties	3,226
Unproved properties (1)	8,597
Corporate acquisition costs	2,364,898
Exploration costs (2)	4,702
Development costs (3)	661,986
Other	16,628
Total	3,060,037

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, 2022.

	DEVELOPMENT	
	GROSS	NET
Oil Wells	199	160.9
Gas Wells	15	12.5
Total	214	173.4

In 2023, we expect to drill approximately:

- 40 oil wells in Alberta;
- 29 natural gas wells in Alberta;
- 1 service well in Alberta;
- 176 oil wells in Saskatchewan; and
- 1 service well in Saskatchewan.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2023, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained above under the subheading "*Statement of Reserves Data and Other Oil and Natural Gas Information – Reserves Data (Forecast Prices and Costs)*".

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	TIGHT CRUDE OIL (Bbls/d))	CONVENTIONAL NATURAL GAS (Mcf/d)	SHALE GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	BOE (Boe/d)
Total Proved						
Central Alberta	11,466	-	96,194	-	10,881	38,380
Northern Alberta and British Columbia	11,912	1,153	100,909	140,303	19,462	72,729
Saskatchewan	51,526	-	16,689	-	1,906	56,213
Other minor areas	39	-	160	-	2	68
Total	74,943	1,153	213,952	140,303	32,251	167,389
Total Proved plus Probable						
Central Alberta	12,677	-	105,269	-	12,259	42,481
Northern Alberta and British Columbia	13,017	1,278	108,720	152,567	21,242	79,085
Saskatchewan	54,532	-	17,833	-	2,041	59,546
Other minor areas	42	-	163	-	2	71
Total	80,268	1,278	231,984	152,567	35,545	181,183

Production History

The following table discloses our average daily production (including production from our major areas) for the year ended December 31, 2022:

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	TIGHT CRUDE OIL (Bbls/d))	CONVENTIONAL NATURAL GAS (Mcf/d)	SHALE GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	BOE (Boe/d)
Central Alberta	11,807	-	97,039	-	9,411	37,392
Northern Alberta and British Columbia	12,786	5,976	40,554	97,299	3,900	45,637
Saskatchewan	55,684	-	19,657	-	2,207	61,166
Other minor areas	164	-	160	-	3	194
Total	80,441	5,976	157,410	97,299	15,521	144,389

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:

	THREE MONTHS ENDED 2022 MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR ENDED DECEMBER 31, 2022
Average Daily Production [1]					
Light and Medium Crude Oil (Bbls/d)	79,406	82,401	79,180	80,776	80,441
Tight Crude Oil (Bbls/d)	3,574	3,256	5,957	11,036	5,976
Natural Gas Liquids (Bbls/d)	14,591	13,465	16,513	17,473	15,521
Conventional Natural Gas (Mcf/d)	159,115	148,777	160,528	161,162	157,410
Shale Gas (Mcf/d)	51,605	50,250	104,358	181,478	97,299
Combined (Boe/d)	132,691	132,293	145,798	166,392	144,389
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	111.65	133.46	111.70	101.55	114.68
Tight Crude Oil ($/Bbl)	118.17	136.33	110.78	109.59	114.79
Natural Gas Liquids ($/Bbl)	54.64	66.38	55.87	46.84	55.30
Conventional Natural Gas ($/Mcf)	4.95	7.59	4.50	5.35	5.56
Shale Gas ($/Mcf)	5.46	8.05	4.66	5.75	5.71
Combined ($/Boe)	84.06	104.83	79.81	72.94	84.49
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	22.86	27.34	25.42	21.86	24.39
Tight Crude Oil ($/Bbl)	4.04	7.63	6.42	13.89	9.71
Natural Gas Liquids ($/Bbl)	17.41	18.42	14.33	12.91	15.52
Conventional Natural Gas ($/Mcf)	0.53	0.64	0.32	0.39	0.47
Shale Gas ($/Mcf)	0.46	0.70	0.35	0.07	0.28
Combined ($/Boe)	16.53	20.08	16.29	13.34	16.35
Production Costs [(2)(3)(4)]					
Light and Medium Crude Oil ($/Bbl)	22.11	23.53	25.26	25.28	24.06
Tight Crude Oil ($/Bbl)	14.47	13.55	14.29	10.75	12.57
Natural Gas Liquids ($/Bbl)	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	1.50	2.11	1.64	2.11	1.84
Shale Gas ($/Mcf)	2.41	2.11	1.96	1.57	1.86
Combined ($/Boe)	16.36	18.18	17.51	16.74	17.18
Resulting Netback Received					
Light and Medium Crude Oil ($/Bbl)	66.68	82.59	61.02	54.41	66.23
Tight Crude Oil ($/Bbl)	99.66	115.15	90.07	84.96	92.51
Natural Gas Liquids ($/Bbl)	37.23	47.96	41.54	33.93	39.77
Conventional Natural Gas ($/Mcf)	2.91	4.83	2.55	2.86	3.26
Shale Gas ($/Mcf)	2.58	5.24	2.35	4.11	3.58
Combined ($/Boe)	51.18	66.57	46.01	42.86	50.96

Notes:

(1) Before the deduction of royalties.

(2) 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.

(3) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(4) Production costs attributable to natural gas liquids have been included in the light and medium crude oil and conventional natural gas production cost amounts.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

As at the date hereof, we have a $2.0 billion Credit Facility with a syndicate of lenders. The Credit Facility consists of a $1.925 billion revolving syndicated facility and a $75.0 million revolving operating facility, with a maturity date of May 31, 2026. The Credit Facility was increased by $395 million from $1.605 billion at June 30, 2022 to $2.0 billion at August 31, 2022 concurrent with the closing of the XTO Transaction. 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.

As noted above under "*History and Development – Developments in 2022*", in February 2022, we transitioned to a SLL on our Credit Facility that includes pricing adjustments related to two key emission reduction performance targets. The SLL has a cumulative pricing adjustment of 5 basis points to the applicable margin, as well as a pricing adjustment of up to 1 basis point to the standby fee, that can result in price increases or decreases depending on performance. Our key performance indicators for the SLL are a 15% reduction to our combined intensity of Scope 1 emissions and Scope 2 emissions by 2025, and a 30% reduction to our methane emissions intensity by 2025, in each case utilizing 2020 emissions intensity as the baseline.

The following table lists our financial covenants as at December 31, 2022:

Covenant Description		December 31, 2022
	Maximum Ratio	
Debt to EBITDA ratio(1)(2)	4.00	0.69
	Minimum Ratio	
EBITDA to interest expense ratio(1)	3.50	45.40

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, 2022, we were compliant with all covenants provided for in the lending agreement in respect of the Credit Facility. 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 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.

Term Loan

On August 31, 2022, we obtained a $705 million Term Loan in conjunction with the closing of the XTO Transaction. The Term Loan has a maturity date of May 31, 2026 and is repayable at any time with no penalty. The Term Loan provides that advances may be made by way of direct advances or banker's acceptances. The Term Loan 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 EBITDA ratio for the most recent quarter.

The significant covenants under the Term Loan are the same as those under the Credit Facility (including the financial covenants described above). As of December 31, 2022, the Corporation was compliant with all covenants provided for in the term loan credit agreement. A copy of the term loan credit agreement in respect of the Term Loan may be accessed through our SEDAR profile at *www.sedar.com*.

Senior Secured Notes

We issued by way of private placement pursuant to a note purchase agreement: (a) $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 (b) $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*".

We repaid $200 million in senior secured notes on January 5, 2022 that had an annual coupon rate of 3.46%.

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 ABCA, 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 provided that, if the authorized Preferred Shares are to be assigned voting or conversion rights, the number of Preferred Shares to be issued may not exceed twenty percent (20%) of the number of issued and outstanding Common Shares at the time of issuance of any such Preferred Shares.

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. Notwithstanding the foregoing, 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.

There are no Preferred Shares outstanding as at the date of this Annual Information Form.

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
2022			
January	9.19	7.61	71,946,340
February	9.68	8.52	70,956,544
March	10.90	8.54	98,466,827
April	11.46	9.61	93,105,933
May	11.50	9.38	100,361,617
June	12.71	8.38	116,345,223
July	9.89	7.70	79,081,738
August	10.155	8.38	67,680,860
September	9.865	8.00	66,475,053
October	10.94	9.10	63,061,793
November	11.52	10.20	52,800,160
December	11.11	9.43	44,934,649
2023			
January	11.44	9.63	52,810,926
February (1 – 21)	11.09	10.07	33,051,288

Prior Sales

During the year ended December 31, 2022, we issued a total of 3,071,989 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 15(d) to our consolidated financial statements for the year ended December 31, 2022 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 during the five preceding years of our directors and executive officers are set out below.

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH WHITECAP	DIRECTOR OR EXECUTIVE OFFICER SINCE	PRINCIPAL OCCUPATION
Mary-Jo E. Case (1)(3) Calgary, Alberta	Director	February 2021	Independent businesswoman with over thirty-five 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.
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	Managing Director and Investment Committee Member of Carbon Infrastructure Partners (formerly, 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 Ltd., an independent engineering consulting firm based in Calgary.
Chandra A. Henry (1)(5) Calgary, Alberta	Director	May 2022	Chief Financial Officer and Chief Compliance Officer of Longbow Capital Inc. ("**Longbow**"), a private equity investment management company based in Calgary, Alberta that invests predominantly in the North American energy markets, since June 2019. Prior thereto, held various senior finance positions, including Chief Financial Officer of WestBlock Inc. from 2018 to 2019, Director of Finance for GMP Securities L.P. from 2016 to 2017 and Chief Financial Officer of FirstEnergy Capital Corp. from 2001 to 2016.

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH WHITECAP	DIRECTOR OR EXECUTIVE OFFICER SINCE	PRINCIPAL OCCUPATION
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 and Chief Experience Officer of Viridian Family Office Inc. (formerly Loram 99 Corporation ("**Loram 99**")), a private company since October 1, 2020 and prior thereto was the Controller and General Manager of Loram 99 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 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 of the Board and Director	June 2013	Independent businessman. Prior to February 1, 2014, he was employed for 13 years by TransAlta Corporation ("**TransAlta**"), 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) Maple Creek, Saskatchewan	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 the principal of Flying W Consulting Inc., a special advisor at Osler, Hoskin & Harcourt LLP, and a partner at CW Cattle Company Ltd. Mr. Wall is an Advisory Board member of the Canadian Global Affairs Institute and the Canadian American Business Council. Mr. Wall is also the Co-Chair of the Canada Asean Business Council.
Grant A. Zawalsky (4)(5) Calgary Alberta	Director	June 2008	Vice Chair and Partner of Burnet, Duckworth & Palmer LLP (Barristers and Solicitors), where he has been a Partner since 1994.
Joel M. Armstrong Calgary, Alberta	Senior Vice President, Production and Operations	May 2010	Our Senior Vice President, Production and Operations.

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH WHITECAP	DIRECTOR OR EXECUTIVE OFFICER SINCE	PRINCIPAL OCCUPATION
Darin R. Dunlop Strathmore, Alberta	Senior Vice President, Engineering	November 2009	Our Senior Vice President, Engineering.
Thanh C. Kang Calgary, Alberta	Senior Vice President & Chief Financial Officer	September 2009	Our Senior Vice President & Chief Financial Officer.
P. Gary Lebsack Calgary, Alberta	Vice President, Commercial Negotiations	September 2009	Our Vice President, Commercial Negotiations since 2022. Prior thereto, our Vice President, Land since 2009.
David M. Mombourquette Calgary, Alberta	Senior Vice President, Business Development & IT	September 2009	Our Senior Vice President, Business Development and IT.
Jeffery B. Zdunich Foothills, Alberta	Vice President, Finance and Controller	January 2015	Our Vice President, Finance and Controller.

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 21, 2023 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 30 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.

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), 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.

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 under the *Bankruptcy and Insolvency Act* (Canada). Mr. Gilbert resigned as a director of LGX immediately following the appointment of the receiver. 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 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. This became effective on September 30, 2019. 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 3, 2019, PricewaterhouseCoopers LLP was appointed receiver.

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, or 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" (as defined by applicable regulations) and ensuring the nature and extent of such transactions are properly disclosed.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

The full text of our Audit Committee mandate 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, Ms. Case and Ms. Henry, 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: *Viridian Family Office Inc.*

Mr. Nikiforuk became the President and Chief Experience Officer of Viridian Family Office Inc. (formerly Loram 99), a private company on October 1, 2020 and prior thereto was the Controller and the General Manager of Loram 99 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.

Kenneth S. Stickland: *Independent Businessman*

Mr. Stickland is an independent businessman. Prior to February 1, 2014, he was employed for 13 years by TransAlta, 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. 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 currently a director of Peyto Exploration & Development Corp., a public oil and natural gas company and was previously a director of Calfrac Well Services Ltd. (2002-22), 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 35 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 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.

Chandra Henry: *Longbow Capital Inc.*

Ms. Henry has more than 25 years of progressive experience in finance, treasury, risk, taxation and operations within the financial services industry crossing multiple geographic and business segments. She is currently the Chief Financial Officer and Chief Compliance Officer of Longbow, a private equity investment management company based in Calgary, Alberta that invests predominantly in the North American energy markets (since June 2019). Prior to Longbow, Ms. Henry held various senior finance positions, including Chief Financial Officer of WestBlock Inc. (2018-19), Director of Finance for GMP Securities L.P. (2016-17) and Chief Financial Officer for FirstEnergy Capital Corp. (2001-16). Ms. Henry has a Bachelor of Commerce degree from the University of Calgary and has earned the Chartered Professional Accountant (CPA, CA), Chartered Financial Analyst (CFA) and Institute of Corporate Directors (ICD.D) designations. In addition, Ms. Henry is a Fundamentals of Sustainability Accounting (FSA) Credential Holder. Ms. Henry currently sits on the board of directors of Headwater Exploration Inc., a public oil and natural gas company (for whom she serves as Chair of the Audit Committee). Ms. Henry has also served on the board of directors (2018-20) and Chair of the Audit and Risk Committee (2019-20) of Pengrowth Energy Corporation, on the board of directors of Bonavista Energy Corporation (2020-22), and as Director, Treasurer and Chair of the Audit Committee of the Alberta Ballet Company (2012-18).

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) ($)	ALL OTHER FEES (4) ($)
2021	370,000	75,000	85,000	-
2022	459,000	70,000	107,000	-

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 of 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 paid 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 our Board. 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
January 2023 to February 2023	$0.0483
July 2022 to December 2022	$0.0367
March 2022 to June 2022	$0.03
October 2021 to February 2022	$0.0225
June 2021 to September 2021	$0.01625
March 2021 to May 2021	$0.01508
May 2020 to February 2021	$0.01425
January 2020 to April 2020	$0.0285

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*".

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 cash flow from operating activities 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, Term Loan 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 ABCA. Pursuant to the ABCA, 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.

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, covenants in our lending agreements, the satisfaction of solvency tests imposed by the ABCA 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 Canadian oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government as well as with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the 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 governments may enact in the future.

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 and construction of related infrastructure; (ii) technical drilling and well requirements; (iii) permitted locations and access to operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions.

The discussion below outlines some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in 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.

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("**OPEC**") forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's zero-COVID policy. OPEC predicts global oil demand to rise by 2.25 million barrels per day in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

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

Natural Gas

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

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. 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

Capacity to transport production from Western Canada to Eastern Canada, the United States and other international markets has been, and continues to be, a major constraint on the exportation of crude oil, natural gas and NGLs. Although certain pipeline and other transportation projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and 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 in the last several years.

Oil Pipelines

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

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

Specific Pipeline Updates

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. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2022. The pipeline is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's initial December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In 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, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge Inc. stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan's efforts to move the dispute to Michigan state court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General intends to appeal the decision.

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

Natural Gas and Liquefied Natural Gas ("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 is generally lower than the prices received in other North American regions.

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. In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "**NGTL System**") and the expanded NGTL System was completed in April 2022.

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**"). With more Alberta and Northeastern British Columbia gas egressing through the CGL Pipeline, the NGTL System is expected to have more capacity, which may result in a closer link between AECO and NYMEX gas prices. Phase 1 of the LNG Canada project reached 70% completion in October 2022, with a completion target of 2025.

In May 2020, TC Energy Corporation sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its regulatory 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. As of November 2022, construction of the CGL Pipeline was approximately 80% complete.

Woodfibre LNG Limited issued a notice to proceed with construction of the Woodfibre LNG project to its prime contractor in April 2022. The Woodfibre LNG project is located near Squamish, British Columbia, and upon completion will produce approximately 2.1 million tonnes of LNG per year. Major construction is set to commence in 2023, with substantial completion of the project expected in late 2027. In November 2022, Enbridge Inc. completed a transaction with Pacific Energy Corporation Limited, the owner of Woodfibre LNG Limited, to retain a 30% ownership stake in the project.

In addition to LNG Canada, the CGL Pipeline and the Woodfibre LNG project, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

Marine Tankers

The *Oil Tanker Moratorium Act* (Canada), 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 from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium.

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 ("**CETA**"), the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most importantly, 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 impact Western Canada's oil and gas industry as a whole, 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.

Canada is also party to the CETA, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"), which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

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

Land Tenure

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 Government of Alberta, among others, announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures.

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 through *An Act to Amend the Indian Oil and Gas Act* and the accompanying regulations. We do not have operations on Indigenous reserve lands.

Surface Rights

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

Royalties and Incentives

General

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

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, both the federal government and 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.

In addition, from time-to-time, including during the COVID-19 pandemic, the federal government creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry as well as other industries in Canada.

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.

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

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

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

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

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

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. Producers and working interest participants may also pay additional royalties to parties other than the freehold mineral owner where such royalties are negotiated through private transactions.

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.

Incentives

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

British Columbia

Crown Royalties

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

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

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

The Crown royalty rate for oil can be as high as 40% and depends on factors such as the volume of oil produced from a particular well or unitized tract and its vintage. Royalty rates are reduced on certain wells under the Old Royalty Programs, 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 of Saskatchewan 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%. Base royalty rates represent the minimum royalty rate payable on production of petroleum substances, regardless of the level of production. Marginal royalty rates charge increasing royalty rates as the level of production increases. Marginal royalty rates, such as those used in Saskatchewan's royalty regime, are designed to allow producers of petroleum products to more quickly recover initial investments at the beginning of a project's life cycle. 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 $3.70 per hectare 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. Manitoba's crown royalty regime is currently under review, with any resulting changes to the regime anticipated to come into effect in 2023.

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

The CERA and the Impact Assessment Act (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. 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 Impact Assessment Agency (the "**IA Agency**") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. 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 75 kilometres of new rights of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

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

In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

Alberta

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

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

The Government of Alberta's land-use policy 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 certain areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place are Fox Creek, Red Deer and Brazeau (the "**Seismic Protocol Regions**"). We do not have operations in the Seismic Protocol Regions. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") 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 British Columbia Oil and Gas Commission ("**BC OGC**") 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 OGC 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.

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

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 OGC before resuming production. The permitting process requires 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 OGC issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). The BC OGC introduced enhancements to the Special Project Order in April 2021, expanding the boundaries of the order. Under the enhanced Special Project Order, a magnitude 3.0 or above seismic event will result in the immediate suspension of fracturing activities from the suspected well(s) for a minimum of five calendar days. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

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 British Columbia Environmental Assessment Office 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 a partner in the Petrinex Database. The Petrinix Database delivers business processes and information required for the assessment, levy, and collection of crown royalties for Alberta, Saskatchewan, Manitoba and British Columbia. It provides information in support of the regulatory mandates and legislation of the provinces, and services that facilitate important industry commercial activities, including partner to partner reporting, oil marketing, financial analytics, compliance assurance and production accounting.

Manitoba

In Manitoba, the Petroleum Branch of the Department of Natural Resources and Northern Development 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

Alberta

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

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

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), provides the backdrop for Alberta's approach to liability management. As a result of 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 came into force in June 2020.

One important step in the shift to the AB LM Framework has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and the granting of new well, facility and pipeline licences in Alberta are subject to AER approval. Previously under the AB LMR Program, as a condition of transferring existing AER licences, approvals and permits, all transfers required transferees to demonstrate that they had a liability management rating of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

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

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

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

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. In 2018, for example, the AER announced a voluntary area-based closure ("**ABC**") program. The ABC program is designed to reduce the cost of abandonment and reclamation operations through 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 performed on inactive assets. We are currently participating in the voluntary ABC program.

British Columbia

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

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 OGC 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 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 OGC, 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.

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

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"), which was updated in January 2023. 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. The SK LLR Program also outlines requirements for security deposits and licence transfers. If a licence holder wishes to transfer a licence, a licence transfer application must be completed through the Integrated Resource Information System ("**IRIS**"). An assessment is conducted on both the transferee and the transferor listed in the IRIS application. To complete the assessment, both a licensee liability rating ("**LLR**") assessment and a proportional risk transfer is conducted. If a licence transfer will result in either the transferor or transferee having an LLR of less than 1.0, the transferor or transferee, as applicable, must submit the amount of security deposit required by the minister.

In February 2021, the Energy Regulation Division of the Ministry of Energy and Resources announced that it was consulting with stakeholders on proposed regulatory enhancements intended to strengthen Saskatchewan's oil and gas liability management framework and reduce the prospect of new orphan oil and gas wells and facilities in Saskatchewan. This process led to the development of the new *Financial Security and Site Closure Regulations* (the "**Closure Regulations**"), which came into force on January 1, 2023.

The Closure Regulations include: (i) changes to the formula for determining if a licensee poses a risk; (ii) annual spend targets for closure activities by licensees; and (iii) new guidance on when a security deposit may be required by a licensee or in connection with a transfer. *The Oil and Gas Conservation Regulations, 2012* (the "**Conservation Regulations**") remain in effect. Among other things, the Conservation Regulations provide a formula for determining a licensee's LLR, outline eligibility requirements for holding licences, and provide guidance on when a security deposit may be required by a licensee or in connection with a transfer.

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.

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 cash flow from operating activities.

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. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

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

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

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $65/tonne of CO2e. While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

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

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

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

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

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

On June 20, 2022, the Clean Fuel Regulations came into force, establishing Canada's Clean Fuel Standard. The Clean Fuel Standard will replace the former Renewable Fuels Regulation, and aims to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives. Coming into force in 2023, the Clean Fuel Standard will impose obligations on primary suppliers of transportation fuels in Canada and require fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

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

Alberta

In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emit roughly 70 megatonnes of GHG emissions per year, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On January 1, 2023, the carbon tax payable in Alberta increased from $50 to $65 per tonne of CO2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. 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 (as amended on January 1, 2023) and replaced the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the 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 2% 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. Facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020, and 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 $65/tonne of CO2e, and will continue to increase in line with the GGPPA minimum charge. Federal carbon pricing mechanisms are not currently in force in British Columbia, as the province's programs currently meet or exceed the federal benchmark stringency requirements.

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

The Government of British Columbia established the CleanBC Industry Fund in 2019 to support clean industry development in the province. The fund uses a portion of carbon tax revenue paid by large emitters to invest in projects aimed at reducing greenhouse gas emissions. In March 2021, the Government of British Columbia temporarily increased the provincial share of funding to up to 90% of project costs with a cap of $25 million per project. In 2021, the CleanBC Industry Fund invested $83.5 million in 32 emissions performance projects across British Columbia.

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "**CleanBC Roadmap**"), aimed at helping British Columbia achieve its 2030 emission reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90% of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries, and for increased support for clean hydrogen and negative emissions technology. Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

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

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 10,000 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 40-45% 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.

The MRGGA and the Saskatchewan O&G Emissions Regulations meet the federal benchmark stringency requirements for certain industrial sectors, but the federal backstop continues to apply to emissions sources not covered in Saskatchewan's emissions legislation. The federal fuel charge continues to apply in Saskatchewan.

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. According to its 2020 and 2021 reports, the province generates nearly 26% of its electricity from renewable energy sources, an increase of 1.6% since 2019.

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 revised in August 2022, and *Directive PNG036: Venting and Flaring Requirements*, which came into force in April 2020 and was last revised in June 2022. 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. In furtherance of these goals and agreements, in March 2021, the Government of Saskatchewan announced it would provide $500,000 to support innovative research and technology for measuring and monitoring gas volumes and emissions, which will be overseen by the Saskatchewan Research Council.

In January 2021, the Government of Saskatchewan announced support for three projects expected to reduce methane emissions, including a new flare-gas-to-power project, an expansion of gas processing facilities, and a new gas fractionation plant. The Saskatchewan Petroleum Innovation Incentive ("**SPII**") and Oil and Gas Processing Investment Incentive ("**OGPII**") give this support. The SPII and OGPII provide a percentage of transferable royalty credits after private funding has been obtained and the facilities have been built.

In September 2021, Saskatchewan's Energy and Resource Minister announced that one of the government's key priorities would be increasing investment in CCUS through enhanced oil recovery projects. In November 2021, Saskatchewan announced that pipelines transporting CO_2 for CCUS are eligible for the provincial Oil Infrastructure Investment Program ("**OIIP**"). The Government of Saskatchewan expects that CCUS projects will attract provincial investment of more than $2 billion and sequester over two million tonnes of CO_2 annually. OIIP will assist in generating a total investment impact of at least $500 million in new and expanded pipeline capacity in Saskatchewan, while encouraging industry adoption of CCUS and further reductions in GHG emissions.

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 federal government has rejected Manitoba's provincial carbon pricing regime. As such, the GGPPA carbon pricing backstop continues to apply in Manitoba.

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.

In July 2020, Manitoba unveiled the Conservation and Climate Fund ("**CCF**"), which provides grants for green projects and initiatives. In October 2021, Manitoba announced $1 million in grants through the CCF to various organizations and projects, including clean technology development and electrification of vehicles and infrastructure. In its 2022 budget, Manitoba announced an investment of over $6 million for twelve initiatives to advance the *Climate and Green Plan Act*, including $1.5 million for expanding the CCF.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of the rights 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 June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

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

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

On June 29, 2021, the British Columbia Supreme Court issued a judgement in *Yahey v British Columbia* (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("**BRFN**") in Northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. The Blueberry Decision may have significant impacts on the regulation of industrial activities in Northeast British Columbia, and may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties, as has been seen in Alberta.

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

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

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

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 Cdn$100,000 made to any level of a Canadian or foreign government (including Indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in 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. Adverse 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.

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

We utilize multi-well pad drilling where practicable. Wells drilled on a pad are not placed on production until all wells on the pad are drilled and completed. In addition, problems affecting a single well could adversely affect production from all of the wells on the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production, or interruption in ongoing production. These delays or interruptions may cause volatility in our operating results.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, 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.

Adverse Economic Conditions

The demand for energy, including crude oil, NGLs and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political development in the U.S., Europe, Asia or elsewhere, there could be a significant adverse effect on global financial markets and commodity prices. In addition, hostilities in the Middle East, Ukraine, and Taiwan and the occurrence or threat of terrorist attacks in the U.S. or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19, may adversely affect us by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas, (ii) impairing our supply chain, for example, by limiting the manufacturing of materials or the supply of goods and services used in our operations, and (iii) affecting the health of our workforce, rendering employees unable to work or travel. These and other factors disclosed elsewhere herein that affect the supply and demand for crude oil, NGLs and natural gas, and our business and industry, could ultimately have an adverse impact on our financial condition, financial performance, and funds flow.

Impacts of Pandemics

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, NGLs and natural gas. Since 2020, oil prices have recovered from their historic lows, but price support from future demand cannot be assured as countries continue to experience varying degrees of virus outbreak and newly emerging virus variants. Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on our operational results and financial condition. Low prices for oil, NGLs and natural gas would reduce our funds flow, and impact our level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, any resurgence of COVID-19 may cause disruptions to production operations, reduced access to materials and services, increased employee absenteeism from illness, and temporary closures of our facilities.

The extent to which our operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond our control, including but not limited to: the duration and scope of the pandemic; additional actions taken by business and government in response to any resurgence of the pandemic; and the speed and effectiveness of responses to combat any resurgence of the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified herein, the extent of which is not yet known.

Prices, Markets and Marketing

Our results of operations and financial condition are dependent upon the prices that we receive for the oil, NGLs and natural gas that we sell. Historically, the oil, NGL and natural gas markets have been volatile and are likely to continue to be volatile in the future. Oil, NGL and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to changes in supply, demand, market uncertainty and other factors that are beyond our control. These factors include, but are not limited to:

- the impact of regional and/or global health related events, such as the ongoing COVID-19 pandemic, on economic activity levels and energy demand;
- global energy policy, including the ability of OPEC (and in particular the Kingdom of Saudi Arabia) and other oil and natural gas exporting nations (and in particular Russia) to set and maintain production levels and influence prices for oil;
- the limitations on the ability of Western Canadian energy producers to export oil, NGLs and natural gas to U.S. markets and other world markets and the resulting discount that Western Canadian energy producers may receive for their products as compared to U.S. and international benchmark commodity prices;
- the availability of transportation infrastructure, and in particular:
  - our ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or alternatively contract for the delivery of our products by rail;
  - deliverability uncertainties related to the distance of our production from existing pipelines, railway lines, and processing and storage facilities; and
  - operational problems affecting the pipelines, railway lines and processing and storage facilities on which we rely;
- increased growth of shale oil and natural gas production in the U.S.;
- production and storage levels of oil, NGLs and natural gas;
- existing and threatened political instability and hostilities in commodity producing regions such as the Middle East, Northern Africa, Russia and elsewhere;
- sanctions imposed on certain oil producing nations (such as Russia) by other countries;
- foreign supply of, and demand for, oil, NGLs and natural gas, including liquefied natural gas;
- weather conditions;
- the overall economic and political environment in Canada, the U.S., Europe, China, Russia, emerging markets and globally;
- the overall level of energy demand;
- government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business;
- currency exchange rates, interest rates and inflation rates;
- the effect of worldwide environmental and/or energy conservation measures;
- the price and availability of alternative energy supplies; and
- the advent of new technologies.

We make price assumptions that are used for planning purposes, and a significant portion of our cash outflows, including capital and transportation commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, our financial results are likely to be adversely and disproportionately affected because these cash outflows are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices. Our risk management arrangements will not fully mitigate the effects of price volatility.

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. 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.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas production, acquisition, development and exploration activities. 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 flow and may have a material adverse effect on our business, financial condition, results of operations and prospects, and as a result, the market price of our Common Shares.

Market Price

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to 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 COVID-19 pandemic, the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and market price of the securities of oil and natural gas companies have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity, debt levels 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 flow, which result from lower commodity prices and any decision by us to finance capital expenditures using funds flow.

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 flow 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, and may also result in the loss of key employees, the disruption of ongoing business, supplier, customer and employee relationships and deficiencies in internal controls or information technology controls. We continually assess the value and mix of our assets in light of our business plans and strategic objectives. 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.

Incorrect Assessment of the Value of Acquisitions

Acquisitions of oil and natural gas properties or companies will be based in part on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated. If actual reserves or production are less than we expect, our revenues and consequently the value of our Common Shares could be negatively affected.

Political Uncertainty

Our results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact our existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits for our activities or restrict the operation of third-party infrastructure that we rely on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact our results.

Other government and political factors that could adversely affect our financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards and mandating the sale of electric vehicles, and the use of alternative fuels or uncompetitive fuel components, could affect the demand for our products. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels, technologies or electric vehicles. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for our products.

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 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, demonstrations and vandalism have the potential to delay and disrupt our activities. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Transportation Constraints and Market Access*".

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 volatile commodity prices, from time to time some 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, the Corporation 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 effect on our financial and operational results. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*" 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 transportation infrastructure, including 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;
- the effects of inclement and severe weather events, including fire, drought, flooding and extreme cold temperatures;
- 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.

If our funds flow and funds from external financing sources are not sufficient to cover our capital expenditure requirements, we may be required to reallocate available capital among our projects or modify our capital expenditure plans, which may result in delays to, or cancellation of, certain projects or deferral of certain capital expenditures. Any change to our capital expenditure plans could, in turn, have a material adverse effect on our growth objectives and our business, financial position, and results of operations. Because of these factors, we could be unable to execute projects on time, on budget, or at all.

Gathering and Processing Facilities, Pipeline Systems, Trucking and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by truck and 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, trucks and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities, pipeline systems and railway lines continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems from time to time affects 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 production or in a reduction of the price we receive for our products. Unexpected shutdowns 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.

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

A portion of 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 we do. 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. To a lesser extent, we also face competition from companies that supply alternative sources of energy, such as wind and solar power. Other factors that could affect competition in the marketplace include additional discoveries of hydrocarbon reserves by our competitors, the cost of production, and political and economic factors and other factors outside of our control.

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, electric vehicle mandates, 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 other hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of hydrocarbons and encourage the use of renewable fuel alternatives (including electric vehicles), which may lessen the demand for petroleum products and put downward pressure on commodity prices. 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

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation, infrastructure and mergers and acquisitions). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas, infrastructure projects and the transfer of assets pursuant to acquisition and divestiture activities. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions.

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for 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. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Indigenous consultation, environmental impact assessments, and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. Further, the ongoing third party challenges to regulatory decisions or orders have reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to the business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

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*".

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 high pressure into tight rock formations that were previously unproductive to stimulate the production of oil, liquids and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing has resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. 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, liquids and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions or bans on hydraulic fracturing in the areas where we operate could reduce the amount of oil and gas that we are ultimately able to produce from our reserves and/or could result in us being unable to economically recover certain of our oil and gas reserves, which in either case could result in a significant decrease in the value of our assets.

Water is an essential component of our drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact our operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on our financial condition, results of operations, and funds flow.

In addition, we must dispose of the fluids produced from oil, liquids and natural gas production operations, including produced water, which we do directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. Government authorities may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or by commercial disposal well vendors that we may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in us or our vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require us or our vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on our business, financial condition, and results of operations.

Alberta

Minor earthquakes are common in certain parts of Alberta. 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. The AER may extend seismic protocols to other areas of the province if necessary, which may adversely affect our operations. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – General – Alberta*".

British Columbia

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 oil and natural gas reservoirs. Future earthquakes in other areas may trigger the introduction of similar requirements elsewhere in the Province, which may adversely affect our operations. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – General – British Columbia*".

Waterflood

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

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 the CO_2 that we use in our operations pursuant to contracts that expire in April 2024 and February 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_2 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 – Regulatory Authorities and Environmental Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and 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.

Climate Change

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

Transition risks

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

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

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

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. We are committed to reporting on our sustainability performance, and consider existing standards such as the Global Reporting Initiative Sustainability Reporting Standards, the Sustainability Accounting Standards Board Oil & Gas – Exploration & Production standard, and recommendations issued by the Task Force on Climate-Related Financial Disclosures. In addition, the Canadian Securities Administrators have published for comment the proposed National Instrument 51-107 – *Disclosure of Climate Related Matters*, which is intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If we are not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, our business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Physical risks

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

Inflation and Cost Management

Our operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and funds flow.

The cost or availability of oil and gas field equipment may adversely affect our ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to our operations for the expected price, on the expected timeline, or at all, may have an adverse effect on our financial performance and funds flow.

Asset Concentration

Our producing properties are geographically concentrated in Western Canada. As a result, to the extent demand for and costs of personnel, equipment, power, services, and resources in Western Canada increase, it could result in a delay or inability to secure such personnel, equipment, power, services and resources. Any delay or inability to secure personnel, equipment, power, services or resources could result in oil, liquids and natural gas production volumes being below our forecasted production volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our financial performance.

As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of operations or production in Western Canada caused by external factors such as governmental regulation, Canadian federal and/or provincial politics, transportation limitations, supply shortages or extreme weather-related conditions.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which may prevent, delay or make operations more difficult. Consequently, municipalities and provincial transportation departments may enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production, if not otherwise tied-in.

Certain of our oil and natural gas producing areas may from time to time be located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of impassable muskeg (swampy terrain). In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties and cause operational difficulties, including damage to machinery, or contribute to personnel injury because of dangerous working conditions.

Our operations are susceptible to the impacts of wildfires and flooding. In addition to the loss of revenue that would result from the loss of production if our operations are affected by wildfires and/or flooding, we would incur delays and expenses responding to such events, repairing damaged equipment, and resuming operations. Although our insurance policies may compensate us for part of our losses, they will not compensate us for all of our losses. In addition, wildfires and/or flooding consume both financial resources and management and employee time that would otherwise be directed towards the development of our business and the pursuit of our business strategy. We can offer no assurance that the severe wildfires and flooding that have at times affected the oil and gas industry in Western Canada will not occur again in the future with equal or greater severity.

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 and/or Common Share repurchases. 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 flow, 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.

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 future net revenue 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, reduce our operations, or terminate our operations on one or more properties. 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/or credit and/or increased capital raising and/or borrowing costs. Recent conditions in the oil and natural gas industry have at times negatively affected the ability of oil and natural gas companies to access additional equity and/or debt financing and/or increased the cost of such financing.

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 and/or credit 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 equity 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, or may force us to divest of certain assets that we would otherwise not sell.

Credit Facility Arrangements

We are required to comply with covenants under our Credit Facility, Term Loan 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, Term Loan and Senior Secured Notes 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, Term Loan 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, the entering into of amalgamations, mergers, take-over bids or acquisitions, and the disposition of assets, among others.

If our lenders or noteholders require repayment of all or a portion of the amounts outstanding under our Credit Facility, Term Loan or Senior Secured Notes 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, Term Loan and Senior Secured Notes, 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, Term Loan or Senior Secured Notes, the lenders or noteholders under our Credit Facility, Term Loan or Senior Secured Notes 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, and may adversely affect the market price of our Common Shares if investors consider our debt levels to be higher than that of our peers.

Derivative Risk Management Contracts

From time to time, we may enter into physical or financial agreements to receive fixed prices on our oil and natural gas production, which is intended to mitigate the effect of commodity price volatility and support our capital budgeting and expenditure plans. However, to the extent that we engage in price risk management activities to protect ourselves 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 risk management arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the contracted 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 contractual arrangement;
- counterparties to the contractual 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.

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

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.

Title to and Right to Produce from Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. 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:

- commodity prices;
- historical production from properties;
- production rates and estimated production decline rates;
- estimated ultimate reserve recovery;
- changes in technology;
- timing, amount and effectiveness of future capital expenditures;
- marketability of oil, NGLs 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, NGL 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 and probable 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, NGL 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, NGL 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 are not undertaken or, if undertaken, 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, our inability to obtain insurance coverage against one or more risks at acceptable premium rates or at all, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Our insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead us to decide to reduce or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, our overall risk exposure could be increased and we could incur significant costs.

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 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. 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. Shareholder dilution may also result from the issuance of Common Shares pursuant to our award incentive plan. For more information regarding our award incentive plan, see our most recent Information Circular and Proxy Statement, financial statements and related management's discussion and analysis filed on our SEDAR profile at *www.sedar.com*.

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), securities law matters, contract disputes and employment matters. 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 effect on our financial condition.

Indigenous Lands and Rights Claims

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

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

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, regulatory authorities in British Columbia ceased granting approvals, and, in some cases, revoked existing approvals, for, among other things crude oil and natural gas activities relating to drilling, completions, testing, production, and transportation infrastructure following a June 2021 British Columbia Supreme Court decision that the cumulative impacts of government-sanctioned industrial development on the traditional territories of a First Nations group in Northeast British Columbia breached that group's treaty rights. While a settlement between the British Columbia government and the First Nations group has recently been announced and the regulatory authorities have resumed granting certain approvals for crude oil and natural gas activities, the long-term impacts of, and associated risks with, the decision on the Canadian crude oil and natural gas industry and Whitecap remain uncertain.

In addition, Canada is a signatory to the UNDRIP and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. In November 2019, the DRIPA became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the UNDRIP Act came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. 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 the DRIPA and the UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. See "*Industry Conditions – Indigenous Rights*".

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 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, or other laws or government incentive programs relating to the oil and natural gas industry, such as the treatment of resource taxation, dividends, share repurchases or capital gains, may in the future be changed or interpreted in a manner that adversely affects us and/or our Shareholders. 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 and/or the detriment of our Shareholders.

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, counterparties to our derivative risk management contracts, 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 and from purchasers of assets from us for various liabilities, including well abandonment and reclamation obligations assumed by the purchasers. 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, from time to time there may be poor credit conditions in the industry generally and/or of one or more of our joint venture partners in particular, which 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. The use of derivative risk management contracts involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We are unable to predict changes in a counterparty's creditworthiness or ability to perform. Even if we accurately predict such changes, our ability to negate this risk may be limited depending upon market conditions and the contractual terms of the agreements. During periods of declining commodity prices, our derivative receivable positions may increase, which would increase our counterparty credit exposure. 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 and officers are engaged in, and will continue to engage in, other activities in the oil and natural gas industry and, as a result of these and other activities, our directors and officers may become subject to conflicts of interest. The ABCA provides that in the event that a director or officer of Whitecap is a party to a material contract or material transaction or proposed material contract or proposed material transaction with us, or is a director or officer of or has a material interest in any person who is a party to a material contract or material transaction or proposed material contract or proposed material transaction with us, the director or officer must disclose the nature and extent of his or her interest and, if a director, must refrain from voting on any resolution to approve the contract or transaction unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA and our Code of Conduct. 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. In addition, the decline in market conditions in recent years has resulted in a significant number of skilled personnel exiting the oil and gas industry and fewer young people entering the industry. 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 Whitecap. 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, consultants, securityholders and other stakeholders, regulators and other third-parties.

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, credit card and banking details (and money), or approval of wire transfer requests, by disguising themselves 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.

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. As a result, 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 conducted through the use of social media platforms.

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.

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, increased costs and/or cost overruns, and reduced access to (or an increase in the cost of) capital, credit and/or insurance coverage. 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 fossil fuel 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, credit and/or insurance coverage, increasing the cost of capital, credit and/or insurance coverage, and decreasing the price and liquidity of our Common Shares.

Changing Investor Sentiment

A number of factors, including the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors', lenders' and insurers' sentiments towards investing in, lending to, and insuring participants in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors, lenders and insurers have announced that they no longer are willing to fund or invest in, lend to, or insure oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors, lenders and insurers are requesting that issuers develop and implement more robust social, environmental and governance policies and practices and make related disclosures. Developing and implementing such policies and practices, and making such related disclosures, 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, and make the related disclosures, as requested by institutional investors, lenders and insurers, may result in such investors reducing their investment in or loan to us, or not investing in or lending to us at all, or such insurers refusing to insure us. Any reduction in the investor, lender or insurance base interested or willing to invest in, lend to or insure participants in the oil and natural gas industry and more specifically, us, may result in limiting our access to capital or insurance, increasing the cost of capital or insurance, and decreasing the price and liquidity of our Common Shares even if our operating results, underlying asset values or prospects have not changed or have improved.

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, assumptions 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:

- Term Loan Credit Agreement dated as of August 31, 2022 in respect of the Term Loan;
- Amended and Restated Credit Agreement dated April 27, 2018 in respect of the Credit Facility, as amended on December 11, 2018, May 28, 2019, June 30, 2020, March 26, 2021 and October 27, 2021, as increased pursuant to its terms by a Commitment Increase Acknowledgment and Confirmation Agreement dated February 24, 2021, and as further increased pursuant to its terms by a Commitment Increase Acknowledgment and Confirmation Agreement dated August 31, 2022;
- Note Purchase Agreement dated as of May 31, 2017, as amended on December 20, 2017, April 27, 2018, December 12, 2018, May 28, 2019, May 14, 2021 and July 7, 2022 in respect of the 3.54% Notes; and
- Note Purchase Agreement dated as of December 20, 2017, as amended on April 27, 2018, December 12, 2018, May 28, 2019, May 14, 2021 and July 7, 2022 in respect of the 3.90% Notes.

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 – Term Loan*" and "*Description of our Capital Structure – Senior Secured Notes*".

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, 2022. 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, 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.

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.

Grant A. Zawalsky, one of our directors, is the Vice Chair and 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 is contained in our proxy materials relating to our most recent annual shareholders meeting. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2022 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 Chair of the Corporate Governance & Compensation Committee

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

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

February 21, 2023

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

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

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, 2022, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $000s)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	December 31, 2022	Canada	-	16,968,561	-	16,968,561

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

7. We have no responsibility to update our 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 9, 2023.

"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. While the Committee reviews such policies and procedures, the oversight of the actual enterprise risks is retained by the Board.

9. The Committee shall oversee Whitecap's cybersecurity policies and procedures and regularly receive reports from management on its activities to protect Whitecap from cybersecurity risks.

10. The Committee shall establish procedures for and, if desired, also engage an independent service provider to assist with:

    - 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, including the resolution of any such complaints or concerns by Management or, if warranted, by the Board.

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

12. 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.

13. 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.

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

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

16. 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.

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 25, 2022.

3800, 525 8TH Avenue SW
Calgary, AB T2P 1G1
Canada

Tel: 403.260.0767
Fax: 403.266.6975

TSX: WCP

www.wcap.ca

13085068.10