ANNUAL INFORMATION FORM
DATED FEBRUARY 20, 2024

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.

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 vendor (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 8, 2024, evaluating the crude oil, natural gas, NGLs and sulphur reserves attributable to all of our oil and natural gas assets as at December 31, 2023.

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

To Convert From	To	Multiply By
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, that we include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements, and matters relating to our ESG reports including the timing thereof; "*General Development of Our Business – History and Development*" with respect to details of the Corporation's 2024 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 2024; "*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; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Significant Factors or Uncertainties Affecting Reserves Data*" as to our expectation that no significant economic factors or significant uncertainties will affect any particular components of our reserves data other than the factors disclosed under this heading, expectations regarding abandonment and reclamation costs and obligations and 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; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information"* with respect to the Corporation's forward contracts and market risk management strategy, expectations with respect to decline rates, future production, reserves, economics, inventories, environmental sustainability, growth and other opportunities, 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, and anticipated drilling activity and production for 2024; "*Dividend Policy*" as to our dividend policy and the future payment of dividends; and "*Legal Proceedings and Regulatory Actions – Reassessment*" with respect to our ongoing tax reassessments, intention to vigorously defend the same, and expectations related to the implications of such reassessments whether successful or unsuccessful.

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 (including tax reassessments by taxation authorities) that may be, or, with respect to our ongoing tax reassessments, have been, brought against us;
- the interpretation of tax legislation and regulations applicable to 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; access to capital and the continued availability of adequate debt and equity financing and funds flow to fund our planned expenditures, dividends, and share repurchases; future exchange rates, interest rates and inflation rates; availability of transportation; the timing and costs of pipeline, storage and facility construction and expansion; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; our ability to efficiently integrate assets and employees acquired through acquisitions; the accuracy of our reserve volumes; effects of regulation by governmental agencies; royalty rates; future operating costs; and expectations and assumptions concerning applicable tax laws and the precedential value of historical Canadian tax case law. 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 Energy ULC
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.
January 1, 2024	Whitecap Energy Canada ULC (formerly XTO Energy Canada ULC)

Following our amalgamation with Whitecap Energy Canada ULC (and the related dissolution of Whitecap Energy Canada (formerly XTO Energy Canada), an Alberta partnership), Whitecap has no material subsidiaries. Our head office is located at Suite 3800, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and our registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

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

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

Developments in 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.sedarplus.ca.* 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.sedarplus.ca*. 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. New to the 2021 ESG Report was a third-party limited assurance of select emissions metrics conducted by an independent firm. A copy of the 2021 ESG Report is available for review on our website at www.wcap.ca.

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 per Common Share ($0.27 per Common Share annualized) beginning with the October dividend payable in November 2021.

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.

In 2021, our expenditures on property, plant and equipment totaled $428.4 million, with 96 percent spent on drilling, completions, and facilities.

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 March 2022, we transitioned to a Sustainability Linked Loan ("SLL") on our Credit Facility that includes pricing adjustments related to two key emission reduction performance targets. For further details, 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 terminated on May 20, 2023. We purchased and cancelled a total of 16,686,000 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 a range of $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.sedarplus.ca*. 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 of $60 million to a range of $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". Whitecap Energy Canada was subsequently dissolved and Whitecap Energy Canada ULC was amalgamated into us.

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 contains a third-party limited assurance of select GHG emissions figures for the year ended December 31, 2021 conducted by an independent firm. A copy of the 2022 ESG Report is available for review on our website at www.wcap.ca.

In 2022, our expenditures on property, plant and equipment totaled $686.5 million, with 96 percent spent on drilling, completions, and facilities.

Developments in 2023

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.

On May 17, 2023, Ms. Vineeta Maguire was elected to our Board of Directors and Mr. Gregory S. Fletcher retired from our Board of Directors.

On May 23, 2023, we commenced a normal course issuer bid to purchase, from time to time, up to 59,724,590 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 22, 2024. As of the date of this Annual Information Form, we have purchased and cancelled a total of 8,624,800 Common Shares pursuant to the bid.

On August 31, 2023, we announced an increase to our monthly dividend from $0.0483 per Common Share to $0.0608 per Common Share ($0.73 per Common Share annualized). The dividend increase was effective with the October dividend payable in November 2023.

On August 31, 2023, we published and posted to our website our 2023 environmental, social and governance report (the "2023 ESG Report"). The 2023 ESG Report confirmed that in connection with transitioning to a sustainability linked loan under our Credit Facility in early 2022, we are 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 2023 ESG Report contains a third-party limited assurance of select GHG emissions figures for the year ended December 31, 2022 conducted by an independent firm. A copy of the 2023 ESG Report is available for review on our website at www.wcap.ca.

On December 11, 2023, we completed the acquisition of certain producing assets, effective October 1, 2023, for total cash consideration (after closing adjustments) of approximately $159.7 million. The assets acquired by us consisted primarily of light and medium crude oil assets located in southwest Saskatchewan.

In 2023, our expenditures on property, plant and equipment totaled $953.8 million, with 98 percent spent on drilling, completions, and facilities.

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 2023, 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 that of the Canadian energy industry.

In March 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 2021 ESG Report, 2022 ESG Report and 2023 ESG Report are 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 2024 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 – Industry Competition*", "*Risk Factors – Availability of CO_2*" and "*Risk Factors – Inflation and Rising Interest Rates*".

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, 2023, we employed 542 full-time employees, including 281 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 8, 2024. The statement is effective as of December 31, 2023. 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, 2023 as contained in the McDaniel Report. The reserves data summarizes the light and medium crude oil, tight oil, shale gas, conventional natural gas and natural gas liquids 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, 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, 2023 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 – Reserves Estimates*".

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, gas hydrates, heavy crude oil, synthetic crude oil or synthetic gas reserves as of December 31, 2023. We had a very immaterial amount of coal bed methane reserves as of December 31, 2023 that we have included with our conventional natural gas reserves throughout this AIF.

Reserves Data (Forecast Prices and Costs)

	SUMMARY OF OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2023 FORECAST PRICES AND COSTS					
	LIGHT AND MEDIUM CRUDE OIL		TIGHT CRUDE OIL		CONVENTIONAL NATURAL GAS (1)	
RESERVES CATEGORY	GROSS (Mbbls)	NET (Mbbls)	GROSS (Mbbls)	NET (Mbbls)	GROSS (MMcf)	NET (MMcf)
PROVED:						
Developed Producing	201,211	166,910	737	572	316,612	288,340
Developed Non-Producing	2,313	2,002	-	-	7,299	6,596
Undeveloped	102,111	86,591	8,664	7,288	162,488	145,806
TOTAL PROVED	305,634	255,503	9,401	7,859	486,399	440,742
TOTAL PROBABLE	107,876	87,683	8,000	6,305	195,066	173,628
TOTAL PROVED PLUS PROBABLE	413,511	343,187	17,400	14,164	681,466	614,370

	SHALE GAS (1)		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	GROSS (MMcf)	NET (MMcf)	GROSS (Mbbls)	NET (Mbbls)
PROVED:				
Developed Producing	319,255	289,719	51,609	42,272
Developed Non-Producing	30,873	27,912	7,553	6,078
Undeveloped	997,109	894,107	111,410	90,050
TOTAL PROVED	1,347,238	1,211,738	170,572	138,399
TOTAL PROBABLE	869,289	754,289	84,118	63,519
TOTAL PROVED PLUS PROBABLE	2,216,527	1,966,027	254,690	201,919

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	8,051,881	6,765,151	5,592,908	4,778,839	4,201,363	18.27
Developed Non-Producing	487,222	385,558	324,110	282,556	252,183	23.43
Undeveloped	9,144,230	6,000,005	4,168,219	3,006,542	2,222,628	11.67
TOTAL PROVED	17,683,333	13,150,714	10,085,237	8,067,937	6,676,174	14.89
TOTAL PROBABLE	11,772,997	6,611,248	4,334,205	3,112,478	2,372,805	13.88
TOTAL PROVED PLUS PROBABLE	29,456,330	19,761,962	14,419,442	11,180,414	9,048,979	14.57

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	6,632,658	5,726,963	4,774,596	4,100,270	3,618,599
Developed Non-Producing	368,179	288,821	240,918	208,504	184,790
Undeveloped	6,898,243	4,396,201	2,944,578	2,030,491	1,419,375
TOTAL PROVED	13,899,081	10,411,985	7,960,092	6,339,264	5,222,764
TOTAL PROBABLE	8,981,798	4,968,909	3,228,122	2,302,646	1,746,148
TOTAL PROVED PLUS PROBABLE	22,880,879	15,380,894	11,188,214	8,641,910	6,968,912

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2023 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (1) ($000s)	ROYALTIES (2) ($000s)	OPERATING COSTS ($000s)	DEVELOP-MENT COSTS ($000s)	ABANDON-MENT AND RECLAMATION COSTS (3) ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
TOTAL PROVED	53,199,050	9,660,133	16,547,020	6,641,458	2,667,016	17,683,333	3,784,252	13,899,081
TOTAL PROVED PLUS PROBABLE	79,167,757	14,987,022	23,622,429	8,369,808	2,732,037	29,456,330	6,575,451	22,880,879

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, 2023 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]	5,926,946	23.27	-
Tight Crude Oil [2][3]	142,528	18.13	-
Conventional Natural Gas [3]	439,038	-	2.66
Shale Gas	3,576,725	-	3.04
	10,085,237		
TOTAL PROVED PLUS PROBABLE			
Light and Medium Crude Oil [2][3]	8,236,098	24.08	-
Tight Crude Oil [2][3]	298,313	21.06	-
Conventional Natural Gas [3]	618,467	-	2.74
Shale Gas	5,266,564	-	2.77
	14,419,442		

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, 2024. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs.

Assumptions for crude oil, natural gas and natural gas liquids benchmark reference pricing, inflation rates 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 Ethane $Cdn/ Bbl	Edmonton Propane $Cdn/Bbl	Edmonton Butane $Cdn/Bbl	Edmonton Cond. & Natural Gas $Cdn/Bbl	INFLATION RATES (2) %/Year	EXCHANGE RATE (3) ($US/$Cdn)
Forecast											
2024	73.67	92.91	77.44	69.01	2.20	6.88	29.65	47.69	96.79	-	0.752
2025	74.98	95.04	80.48	71.90	3.37	10.76	35.13	48.83	98.75	2.0	0.752
2026	76.14	96.07	81.84	72.78	4.05	13.17	35.43	49.36	100.71	2.0	0.755
2027	77.66	97.99	83.61	74.41	4.13	13.44	36.14	50.35	102.72	2.0	0.755
2028	79.22	99.95	85.78	76.56	4.21	13.71	36.86	51.35	104.78	2.0	0.755
2029	80.80	101.94	87.49	78.10	4.30	14.00	37.60	52.38	106.87	2.0	0.755
2030	82.42	103.98	89.24	79.67	4.38	14.28	38.35	53.43	109.01	2.0	0.755
2031	84.06	106.06	91.01	81.27	4.47	14.58	39.12	54.50	111.19	2.0	0.755
2032	85.74	108.18	92.83	82.90	4.56	14.87	39.90	55.58	113.41	2.0	0.755
2033	87.46	110.35	94.69	84.57	4.65	15.17	40.70	56.70	115.67	2.0	0.755
2034	89.21	112.56	96.58	86.26	4.74	15.48	41.51	57.83	117.98	2.0	0.755
2035	90.99	114.81	98.52	87.99	4.84	15.79	42.34	58.99	120.34	2.0	0.755
2036	92.81	117.10	100.49	89.75	4.94	16.10	43.19	60.17	122.75	2.0	0.755
2037	94.67	119.45	102.50	91.54	5.03	16.42	44.06	61.37	125.20	2.0	0.755
2038	96.56	121.83	104.55	93.37	5.14	16.75	44.94	62.60	127.71	2.0	0.755
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.755

Notes:

(1) As at January 1, 2024.
(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, 2023, excluding price risk management activities, were $94.35/Bbl for light and medium crude oil, $100.16/Bbl for tight crude oil, $2.81/Mcf for conventional natural gas, $2.86/Mcf for shale gas and $38.90/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, 2022	329,235	118,896	448,131	10,441	8,850	19,291
Extensions & Improved Recovery (1)	14,407	4,331	18,738	-	-	-
Technical Revisions (2)	4,257	(7,366)	(3,109)	2,696	(864)	1,831
Discoveries	-	-	-	-	-	-
Acquisitions (3)	11,154	5,010	16,164	-	-	-
Dispositions (3)	(26,486)	(12,878)	(39,364)	-	-	-
Economic Factors (4)	606	(116)	489	12	14	26
Production	(27,539)	-	(27,539)	(3,748)	-	(3,748)
December 31, 2023	305,634	107,876	413,511	9,401	8,000	17,400

	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, 2022	571,350	241,899	813,249	1,258,266	877,640	2,135,906
Extensions & Improved Recovery (1)	49,404	14,370	63,774	217,406	8,996	226,402
Technical Revisions (2)	4,804	(20,731)	(15,926)	(60,070)	(19,271)	(79,342)
Discoveries	-	-	-	-	-	-
Acquisitions (3)	1,084	1,031	2,115	-	-	-
Dispositions (3)	(86,004)	(41,793)	(127,797)	-	-	-
Economic Factors (4)	(2,386)	284	(2,102)	(3,104)	1,925	(1,179)
Production	(51,877)	-	(51,877)	(65,260)	-	(65,260)
December 31, 2023	486,377	195,060	681,437	1,347,238	869,289	2,216,527

NATURAL GAS LIQUIDS			
	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)
December 31, 2022	157,609	100,105	257,714
Extensions & Improved Recovery (1)	31,921	(8,461)	23,460
Technical Revisions (2)	(7,448)	(4,811)	(12,259)
Discoveries	-	-	-
Acquisitions (3)	201	210	411
Dispositions (3)	(5,121)	(3,072)	(8,193)
Economic Factors (4)	(277)	147	(131)
Production	(6,313)	-	(6,313)
December 31, 2023	170,572	84,118	254,690

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, 2023 plus any production from the acquisition dates to December 31, 2023. The dispositions amount is the estimate of reserves at December 31, 2022 less any production from December 31, 2022 to the disposition dates.
(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
2021	25,865	115,566	1,964	10,197	36,292	148,129
2022	8,981	106,369	-	9,393	66,728	190,371
2023	16,554	102,111	-	8,664	36,514	162,488

	SHALE GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2021	187,636	218,424	18,955	29,090
2022	783,046	944,099	81,545	104,449
2023	214,168	997,110	29,542	111,410

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 415.7 MMboe of proved undeveloped reserves with $5,892.1 million of associated undiscounted capital as at December 31, 2023.

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
2021	18,605	60,514	(142)	8,711	20,734	100,742
2022	3,443	56,710	-	8,536	46,903	131,825
2023	6,693	51,404	-	7,751	11,174	99,204

	SHALE GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2021	109,137	143,728	11,499	19,768
2022	671,990	800,145	67,647	85,041
2023	12,234	773,581	(8,889)	67,557

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 272.4 MMboe of probable undeveloped reserves with $1,724.8 million of associated undiscounted capital as at December 31, 2023.

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, 2023, we had 14,804.8 net wells for which we expect to incur abandonment and reclamation costs. The McDaniel Report deducted $2,732.0 million (undiscounted) and $508.3 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)
2024	998,553	1,024,084
2025	1,205,875	1,244,807
2026	1,217,565	1,341,342
2027	1,154,167	1,268,568
2028	1,111,590	1,331,187
Remaining	953,708	2,159,820
Total (Undiscounted)	6,641,458	8,369,808

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, 2023.

East Division

Our East Division is comprised of four regions: Central Alberta, West Saskatchewan, East Saskatchewan and Weyburn.

Our Central Alberta region represents the bulk of our Cardium and liquids-rich Mannville assets, which are primarily focused in 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. These assets provide sizeable cashflow generation with the optionality to transition to a growth model.

In addition to these core horizons, further value creation is being generated through tertiary recovery (CO_2 flood) in the Viking horizon in Joffre. Whitecap is using its world-class expertise in CO_2 enhanced oil recovery ("EOR") and sequestration to maximize value in this pool and continue to drive down our GHG emissions intensity.

Our West Saskatchewan region is comprised of our Viking resource light oil play and Southwest Saskatchewan medium oil play.

Focus areas targeting the Viking are Kerrobert, Plenty, Dodsland, Lucky Hills, Whiteside, and Elrose. The key characteristics of this play are high netback 38° – 40° API light oil, large inventory, predictable geology and production profiles, as well as consistent and repeatable economics. Lucky Hills, Whiteside, Plenty, Elrose and Kerrobert West are characterized by horizontal primary oil development wells with quick payouts and a high operating netback. The Dodsland and Kerrobert East properties are characterized by low decline waterflood supported production from legacy vertical and horizontal infill wells. The Viking oil play provides some of the fastest project payouts in the industry. With high confidence production results and no facility or marketing constraints, this area provides flexible opportunities for growth.

Our Southwest Saskatchewan 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 the Whitecap portfolio opportunistically as an acquisition in 2016 and continues to generate significant free funds 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 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 land base are continually being pursued. These properties had not seen significant development prior to Whitecap 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.

Our East Saskatchewan region is underpinned by the premier Frobisher Conventional Mississippian light oil play characterized by stacked flow units, 30° – 40° API oil and wells with high deliverability and oil recovery supported by an active regional aquifer. Whitecap’s Frobisher focus area consists of a consolidated land base, established oil and gas conservation infrastructure, and significant high quality inventory that generates high netbacks and significant free cash flow. Evolving opportunities include multi-legged horizontal drilling, well re-entry techniques, multi-well pads and organic inventory expansion initiatives. Whitecap's Southeast Saskatchewan region is further complimented by opportunities in the Alida (conventional) and Midale (unconventional) formations which benefit from established infrastructure and efficiencies associated with on-going development in the region.

The Weyburn property is located south of Weyburn, Saskatchewan. The Weyburn property is one of the largest carbon capture and utilization storage ("CCUS") projects in the world and highlights our commitment to environmental sustainability as a core value. This internationally recognized, world class project has safely stored over 40 million tonnes of CO2. Since 2019, we have stored ~1.8 million tonnes of CO2 per year. Whitecap has a 65.3% operated working interest in the Weyburn Unit which produces primarily light oil from the Midale reservoir. The Weyburn Unit has been in existence since 1963. Waterflood operations commenced in the 1960’s with world class CO2 EOR development commencing in 2000. Significant development opportunities remain to expand the Weyburn CO2 flood and further support the low 3-5% base decline rate in conjunction with a very low maintenance capital requirement.

West Division

Our West Division is comprised of three regions: Smoky, Kaybob and PRA.

The properties in our Smoky region include Kakwa and Resthaven, all located in Northwest Alberta. The primary reservoir being developed is the Montney resource play, mainly comprised of condensate-rich natural gas. This area utilizes pad-based horizontal drilling and multi-stage fracturing, including extended reach horizontal wells. The region is comprised of large-scale opportunities and significant inventory setting it up to provide material future organic growth.

Kaybob is located in the Fox Creek region of Northwest Alberta. The primary reservoir being developed is the Duvernay resource play, mainly comprised of condensate-rich natural gas. This area utilizes pad-based horizontal drilling and multi-stage fracturing, including extended reach horizontal wells. The region is comprised of large-scale opportunities, significant inventory and a 100% owned natural gas processing facility setting it up to provide material future organic growth.

The Peace River Arch is Whitecap's original asset area. It is underpinned by the conventional Montney light oil waterflood pool in Valhalla. We are actively exploiting Valhalla's ideally situated infrastructure by expanding our presence in the area through the Charlie Lake and Montney oil resource plays. In 2023, Whitecap expanded the capacity of the Valhalla infrastructure as well as drilled our first unconventional Montney locations in the Peace River Arch area resulting in numerous opportunities for growth in the future.

Also being developed in the area is our Cardium oil play, focused in the Wapiti area, which provides repeatable, high quality light oil horizontal drilling inventory.

Oil and Natural Gas Wells

The following table summarizes, as at December 31, 2023, 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	2,205	1,760.8	175	63.5	1,283	962.7	1,007	626.6
British Columbia	205	192.8	15	7.1	132	125.9	15	9.9
Saskatchewan	6,390	5,318.4	42	6.8	4,498	3,716.0	182	118.8
Total	8,800	7,272.0	232	77.4	5,913	4,804.6	1,204	755.3

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, 2023:

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES (1)(2)(3)	
	GROSS	NET	GROSS	NET	GROSS	NET
Alberta	999,630	817,072	1,061,188	731,858	2,060,818	1,548,930
British Columbia	25,921	18,055	63,108	55,788	89,029	73,843
Saskatchewan	364,185	311,498	718,814	548,144	1,082,999	859,642
Manitoba	-	-	160	-	160	-
Total	1,389,736	1,146,625	1,843,270	1,335,790	3,233,006	2,482,415

Notes:

(1) Includes our interest in approximately 702,509 gross (559,862 net) acres of unproved property land holdings. See "*Properties with no Attributed Reserves*" below.
(2) Rights to explore, develop and exploit 83,905 gross (81,465 net) acres of our land holdings could expire by December 31, 2024 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, 2023:

	GROSS ACRES	NET ACRES
Alberta	145,728	116,137
British Columbia	42,896	34,186
Saskatchewan	513,885	409,539
Total	702,509	559,862

Note:

(1) Approximately 42,414 gross (41,180 net) acres of these land holdings could expire by December 31, 2024.

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 audited annual consolidated financial statements for the year ended December 31, 2023. See also "*Risk Factors – Derivative Risk Management Contracts*".

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2023:

EXPENDITURE	YEAR ENDED DECEMBER 31, 2023 ($000s)
Property acquisition costs:	
Proved properties	217,969
Unproved properties (1)	2,063
Corporate acquisition costs	19,540
Exploration costs (2)	6,016
Development costs (3)	931,508
Other	14,247
Total	1,191,343

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, 2023.

	DEVELOPMENT	
	GROSS	NET
Oil Wells	181	156.7
Gas Wells	28	27.6
Service Wells	6	4.8
Total	215	189.1

In 2024, we expect to drill approximately:

- 28 oil wells in Alberta;
- 34 natural gas wells in Alberta;
- 1 service well in Alberta; and
- 143 oil wells in Saskatchewan.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2024, 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						
East Division	63,929	-	102,801	-	11,894	92,957
West Division	9,743	16,279	42,311	207,166	8,779	76,381
Total	73,672	16,279	145,112	207,166	20,673	169,337
Total Proved plus Probable						
East Division	68,842	-	114,420	-	13,178	101,090
West Division	10,327	17,930	45,309	225,479	9,417	82,805
Total	79,169	17,930	159,729	225,479	22,595	183,895

Production History

The following table discloses our average daily production (including production from our major areas) for the year ended December 31, 2023:

	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)
East Division	64,198	-	103,992	-	11,904	93,433
West Division	11,235	10,286	45,752	171,178	5,392	63,068
Total	75,433	10,286	149,744	171,178	17,296	156,501

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 2023 MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31	YEAR ENDED DECEMBER 31, 2023
Average Daily Production [1]					
Light and Medium Crude Oil (Bbls/d)	76,917	72,896	74,981	76,943	75,432
Tight Crude Oil (Bbls/d)	9,359	9,753	10,257	11,745	10,286
Natural Gas Liquids (Bbls/d)	16,655	15,448	17,804	19,241	17,296
Conventional Natural Gas (Mcf/d)	155,135	137,083	151,519	155,217	149,744
Shale Gas (Mcf/d)	158,024	157,329	172,384	196,539	171,178
Combined (Boe/d)	155,124	147,166	157,026	166,554	156,501
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	90.54	89.96	103.79	92.99	94.35
Tight Crude Oil ($/Bbl)	101.56	95.28	103.27	100.40	100.16
Natural Gas Liquids ($/Bbl)	47.50	33.58	36.75	37.85	38.90
Conventional Natural Gas ($/Mcf)	3.49	2.57	2.76	2.40	2.81
Shale Gas ($/Mcf)	3.62	2.61	2.77	2.54	2.86
Combined ($/Boe)	63.30	59.58	66.17	59.66	62.17
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	16.89	17.93	21.21	18.68	18.68
Tight Crude Oil ($/Bbl)	15.99	4.46	8.81	10.31	9.83
Natural Gas Liquids ($/Bbl)	9.78	3.39	5.45	8.38	6.84
Conventional Natural Gas ($/Mcf)	0.59	0.10	0.20	0.26	0.29
Shale Gas ($/Mcf)	0.53	(0.05)	0.02	0.09	0.14
Combined ($/Boe)	11.51	9.57	11.53	10.66	10.83
Production Costs [2][3][4]					
Light and Medium Crude Oil ($/Bbl)	25.77	29.08	28.01	26.95	27.43
Tight Crude Oil ($/Bbl)	10.63	13.19	12.59	12.84	12.36
Natural Gas Liquids ($/Bbl)	-	-	-	-	-
Conventional Natural Gas ($/Mcf)	1.42	0.28	0.19	0.04	0.49
Shale Gas ($/Mcf)	1.77	2.20	2.10	2.14	2.06
Combined ($/Boe)	16.64	17.89	16.69	15.92	16.76
Resulting Netback Received					
Light and Medium Crude Oil ($/Bbl)	47.88	42.95	54.57	47.36	48.24
Tight Crude Oil ($/Bbl)	74.94	77.63	81.87	77.25	77.98
Natural Gas Liquids ($/Bbl)	37.73	30.18	31.30	29.47	32.06
Conventional Natural Gas ($/Mcf)	1.48	2.19	2.37	2.10	2.03
Shale Gas ($/Mcf)	1.32	0.46	0.65	0.32	0.66
Combined ($/Boe)	35.15	32.11	37.95	33.08	34.58

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

In March 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, 2023:

Covenant Description		December 31, 2023
	Maximum Ratio	
Debt to EBITDA ratio(1)(2)	4.00	0.70
	Minimum Ratio	
EBITDA to interest expense ratio(1)	3.50	27.07

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, senior secured notes, letters of credit, and dividends declared.

As of December 31, 2023, we were compliant with all covenants provided for in the lending agreement in respect of the Credit Facility. Copies of our credit agreements and amendments may be accessed through our SEDAR+ profile at *www.sedarplus.ca*.

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, 2023, 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.sedarplus.ca*.

Senior Secured Notes

We issued by way of private placement pursuant to note purchase agreements: (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*". As of December 31, 2023, the Corporation was compliant with all covenants provided for in the note agreement. Copies of the note agreement and amendments may be accessed through our SEDAR+ profile at www.sedarplus.ca.

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
2023			
January	11.44	9.63	52,810,926
February	11.09	9.87	46,207,745
March	11.04	9.14	58,514,526
April	11.16	10.41	32,017,855
May	10.77	9.26	33,538,693
June	9.95	8.90	34,121,017
July	10.67	9.095	31,172,715
August	11.25	10.42	39,801,076
September	11.91	11.24	40,672,894
October	11.48	10.43	50,370,932
November	10.91	9.27	65,085,286
December	9.53	8.65	41,988,515
2024			
January	9.09	8.41	52,930,773
February (1 – 20)	9.07	8.15	25,203,999

Prior Sales

During the year ended December 31, 2023, we issued a total of 3,231,220 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 audited annual consolidated financial statements for the year ended December 31, 2023 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 as of the date of this Annual Information Form 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. 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.
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., 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.
Vineeta Maguire(2)(4) Calgary, Alberta	Director	May 2023	Independent businesswoman. Ms. Maguire was Vice President, Supply Management Services, North America at Ovintiv Inc. during the period of 2014 to 2023, and Vice President, Canadian Operations at Ovintiv Inc. during the period of 2012 to 2014. Prior thereto, Ms. Maguire was Team Lead, New Plays & Subsurface Technical at Encana Corporation (now Ovintiv Inc.) during the period of 2008 to 2012. She previously held positions in asset management and operations at BP Canada Petroleum Company Ltd., Amoco/BP Canada Petroleum Company Ltd. and Petro-Canada Resources Ltd.

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	Independent businessman. Prior to his retirement in September 2023, he was the President and Chief Executive Officer and a director of Heritage Resources LP, a wholly owned oil and gas business of the 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 American Business Council and the Fraser Institute. 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
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 20, 2024 our directors and executive officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 7.9 million Common Shares or approximately 1.3% 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 – Conflicts of Interest*".

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, 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.

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) ($)	ALL OTHER FEES (4) ($)
2022	459,000	70,000	107,000	-
2023	517,000	35,000	69,000	-

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
October 2023 to February 2024	$0.0608
January 2023 to September 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

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, the amount of our indebtedness, foreign exchange rates, interest 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, interest 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 Corporation. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells and construction of related infrastructure; (ii) technical drilling and well requirements; (iii) permitted locations and access 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. 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, where the Corporation's assets are primarily located. While these matters do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly sized industry participants with similar assets and operations, investors should consider such matters carefully.

Pricing in Canada

The price of crude oil, natural gas, and NGLs is negotiated by buyers and sellers. A number of local, regional, North American and global factors may influence prices, including supply and demand, quality of product, distance to market, availability of transportation, value of refined products, prices of competing products, contract term, weather conditions, and contractual terms of sale.

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

Producers negotiate with pipeline operators to transport their products to market on a firm, 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-owned Trans Mountain Corp. acquired the Trans Mountain Pipeline in August 2018. Following the resolution of various legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Budget increases and in service date delays have been attributed to, among other things, high global inflation, global supply chain challenges, the widespread flooding in British Columbia in late 2021, and unexpected major archeological discoveries. On June 1, 2023, Trans Mountain Corp. submitted an application to the Canada Energy Regulator proposing a base toll of $11-12 per barrel, which was met with great opposition; a multiple stage hearing process is underway, and a decision has not yet been released. The federal government has been in discussions with Indigenous groups and businesses regarding selling significant equity stakes in the pipeline, however no agreements have yet been reached.

In December 2023, the Canada Energy Regulator denied Trans Mountain's pipeline variance application for the Mountain 3 Horizontal Directional Drill (located in the Fraser Valley), however in January 2024, it approved the request with conditions, meaning the Trans Mountain Pipeline expansion can now proceed toward completion in compliance with the order. The pipeline is expected to be in service in 2024, an extension from the initial December 2022 estimate.

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"). The NGTL System is in the midst of implementing a $6.5 billion infrastructure program, which added 1.3 billion cubic feet per day of capacity in 2022, and an additional 2.2 billion cubic feet per day of capacity is planned between 2023 and 2026.

There are currently eight LNG export projects at different stages of development across the country with most being located in British Columbia. LNG Canada's LNG liquefaction facility and export terminal in Kitimat, British Columbia will be Canada's first operational large-scale LNG export facility. Once complete, producers in northeastern British Columbia will be able to transport natural gas to the facility via the Coastal GasLink pipeline (the "CGL Pipeline"). The LNG Canada facility is more than 85% complete, and the CGL Pipeline is now mechanically complete. The facility will launch its startup program in 2024 to test and fine tune equipment, which will take over a year to complete, before becoming fully operational. The Woodfibre LNG project is located near Squamish, British Columbia, and upon completion will produce approximately 2.1 million tonnes of LNG per year. Construction began in the fall of 2023 and substantial completion of the project is expected in late 2027. Most of the other projects target becoming operational between 2027 and 2030, although there is no guarantee that all or any of these projects will proceed.

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.

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 is Canadian federal government ownership of mineral lands on Indian reserves (as designated under the *Indian Act*), which is managed and regulated by a separate government body according to distinct legislation. We do not have operations on Indian reserve lands.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, facility or pipeline.

Royalties and Incentives

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 and other industries in Canada.

Regulatory Authorities and Environmental Regulation

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

Liability Management

The Alberta Energy Regulator (the "AER") administers several liability management programs to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The province is gradually moving from a prescriptive framework toward a more holistic approach to liability management.

Alberta has an orphan fund to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in certain of the AER's programs if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The orphan fund is funded through a levy and a loan from the provincial government.

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. The burden of a defunct licensee's abandonment and reclamation obligations first falls 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.

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.

Similar to Alberta, the BC regulator has moved away from the formulaic approach to liability management toward a more holistic assessment of a permit holder's ability to meet its abandonment and reclamation obligations. Additionally, similar to Alberta's orphan fund, BC and Saskatchewan have programs to address the abandonment and reclamation costs for orphan sites. The Government of Manitoba has not implemented a liability management rating program like those found in the other Western Canadian provinces, however, the province has an abandonment fund that may be used to operate or abandon a well or facility when the licensee or permittee fails to comply with the legislation, to rehabilitate the site of an abandoned well or facility, or to address any adverse effect on property caused by a well or facility.

The British Columbia Dormancy and Shutdown Regulation establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036, with additional regulated timelines for sites that have become dormant between 2019 and 2023 and will become dormant during or after 2024.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain, and it is not possible to predict what future policies, laws and regulations will entail. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Corporation's operations and cash flow 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, Canada pledged to (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) cease to export thermal coal by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) halt direct public funding to the global fossil fuel sector by the end of 2022; and (v) commit that all new vehicles sold in the country will be zero-emission on or before 2040. During the 2023 United Nations Climate Change Conference, Canada signed an agreement with nearly 200 other parties, which includes renewed commitments to transitioning away from fossil fuels and further cutting GHG emissions.

In 2022, the federal government published a discussion paper that outlined two potential regulatory options for capping emissions from the oil and gas sector: (i) to implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) to modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. The federal government has completed its formal engagement on potential regulatory options to cap emissions and released the proposed regulatory framework on December 7, 2023, which is discussed in more detail below.

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. The GGPPA 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, commonly referred to as the federal backstop program, 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 increases by $15 per year until it reaches $170/tonne of CO2e in 2030 (currently $80/tonne). 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 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 regulations aim to reduce the oil and gas sector's methane emissions by 40–45% by 2025, relative to 2012 emissions.

In December 2023, the federal government released proposed amendments to the Federal Methane Regulations in order to further reduce upstream methane emissions and to contribute to Canada meeting its international climate-related commitments. The proposed amendments would build on the existing requirements and increase stringency by introducing new prohibitions and limits on certain intentional emissions, a new risk-based approach around unintentional emissions, and a new performance-based approach for compliance that relies on continuous emissions monitoring systems, among other things. The proposed amendments are targeted to come into force in January 2027.

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.

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 to reduce its 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. Currently, there are no approved federal offset protocols applicable to the oil and gas sector.

On June 20, 2022, the federal Clean Fuel Regulations came into force and took effect July 2023. The Clean Fuel Regulations aim to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives, imposing obligations on primary suppliers of transportation fuels in Canada, and requiring 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).

Additionally, on December 7, 2023, the Minister of Environment and Climate Change and the Minister of Energy and Natural Resources, introduced Canada's draft cap-and-trade framework to limit emissions from the oil and gas sector. The proposed Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap proposes capping 2030 emissions at 35 to 38 percent below 2019 levels, while providing certain flexibilities to emit up to a level around 20 to 23 percent below 2019 levels. The purpose of the proposed cap is to ensure that Canada is on track to meet its target of achieving net-zero by 2050. It is expected that the regulations will be finalized and released sometime in 2025 with annual reporting required as early as 2026 and a phasing in period taking place between 2026 and 2030. As proposed, this cap-and-trade framework would impose a carbon price on oil and gas sector GHG emissions in addition to the existing OBPS programs.

The Government of Canada is also in the midst of developing a 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. As part of the 2021 budget, the federal government committed to investing $319 million over seven years to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050. The House of Commons is currently considering legislation pursuant to which it will start paying subsidies for carbon capture and net-zero energy projects; an update is expected in 2024.

In June 2023, the International Financial Reporting Standards Foundation ("IFRS") issued two international reporting standards on sustainability: IFRS S1, which addresses sustainability-related disclosure, and IFRS S2, which addresses climate-related disclosure. The new standards require issuers, among other things, to include quantitative data regarding their climate change considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 GHG emissions. While Canadian companies are not required to follow IFRS S1 and IFRS S2 at this time, the Canadian Securities Administrators is considering amending Canadian reporting requirements to include the new international standards, however to what extent they will be adopted remains unclear.

Provincial

In December 2016, the Oil Sands Emissions Limit Act (Alberta) came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, 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 81 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 and Saskatchewan. The carbon tax payable in both provinces will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030 (currently $80/tonne). In December 2019, the federal government approved Saskatchewan's Management and Reduction of Greenhouse Gases Regulation ("MRGHGR") and Alberta's Technology Innovation and Emissions Reduction ("TIER") regulation, which applies to large emitters. The MRGHGR came into effect on January 1, 2019 (as amended on January 1, 2023). 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 MRGHGR and TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, and the federal backstop continues to apply to emissions sources not covered by the regulation.

In Manitoba, the federal system applies in full, whereas it does not apply in British Columbia, which has its own economy-wide carbon pricing system.

The governments of British Columbia, Alberta and Saskatchewan enacted provincial regulations designed to lower annual methane emissions from the oil and gas sector 45% by 2025, in line with the federal methane regulations and effective January 1, 2020. The Government of Canada announced equivalency agreements with each province regarding the regulation of methane emissions from the oil and gas sector such that the federal methane regulations would not apply in these jurisdictions. The Government of Manitoba did not enact similar legislation; as such, the federal methane regulations are in effect in that province as of January 1, 2020.

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 on 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 (the "Implementation Secretariat"), 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. On June 21, 2023, the Implementation Secretariat released The United Nations Declaration on the Rights of Indigenous Peoples Act Action Plan with respect to aligning federal laws with UNDRIP, which has a 2023-2028 implementation timeframe.

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 stated that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward.

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. Beaver Lake Cree Nation brought a similar lawsuit against the Government of Alberta in 2008, which had stalled, but is scheduled to be heard in early 2024. The long-term impacts of the Blueberry Decision and the Duncan's First Nation's and Beaver Lake Cree Nation's lawsuits on the Canadian oil and gas industry remain uncertain.

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. The risks discussed below are based on certain assumptions we have made which later may prove to be incorrect or incomplete. Investors are encouraged to perform their own investigation with respect to our business, financial condition and prospects.

Our business could also be affected by additional risks and uncertainties not currently known to us or that we currently deem to be immaterial. If any of these risks occur, it could materially harm our business, financial condition, results of operations and funds flow, or impair our ability to implement business plans, complete development activities as scheduled, or pay dividends at the current dividend level or at all. In that case, the market price of the Common Shares could decline and you could lose all or part of your investment. Before deciding whether to invest in any of our securities, investors should carefully consider the risks set out below. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us or that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations. The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled "*Notice to Reader – Special Note Regarding Forward-Looking Statements*".

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, or 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 or 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 EOR 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 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 developments 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 elsewhere 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 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.

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 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;
- occurrence or threat of terrorist attacks in the United States or other countries that could adversely affect the global economy;
- 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, current perceptions of the oil and natural gas market and worldwide pandemics. In recent years, the volatility of commodity prices 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 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 decided to decrease or eliminate their ownership in oil and natural gas entities which may impact the liquidity of certain securities and put downward pressure on the trading price of those securities. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity, debt levels, dividend 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 and debt levels, operating costs, royalty burdens, foreign exchange rates, restrictions under contracts on the payment of dividends 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 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 capital 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 state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, 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 licences 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. 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 resulting in a rise in civil disobedience surrounding oil and natural gas development —particularly with respect to infrastructure projects such as pipelines. 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*".

Israel-Palestine War

On October 7, 2023, Hamas terrorists infiltrated Israel's southern border from the Gaza Strip and conducted a series of attacks on civilian and military targets. Hamas also launched extensive rocket attacks on the Israeli population and industrial centres located along Israel's border with the Gaza Strip and in other areas within the State of Israel. Following the attack, Israel's security cabinet declared war against Hamas and the military campaign against these terrorist organizations has launched a series of responding attacks in Palestine.

The outcome of the conflict has the potential to have wide-ranging consequences on the world economy and the global price of oil. While neither Israel nor the Gaza Strip are significant oil producers, there is a risk that the conflict could lead to wider regional instability in the Middle East, home to some of the world's biggest oil producers. To date, these events have not impacted our ability to carry on business, and there have been no significant delays or direct security issues affecting our operations, offices or personnel. The long-term impacts of the conflict remain uncertain and we continue to monitor the evolving situation.

Russian Ukrainian War

In February 2022, Russian military forces invaded Ukraine. Ukrainian military personnel and civilians continue to actively resist the invasion. Many countries throughout the world have provided aid to Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in its resistance to the Russian invasion. The North Atlantic Treaty Organization ("NATO") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. Additionally, certain countries including Canada have imposed strict financial and trade sanctions against Russia. The outcome of the ongoing conflict and related sanctions remains uncertain and may have wide-ranging consequences on the peace and stability of the region and the world economy.

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 such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on our financial and operational results. See "*Risk Factors – Third Party Credit Risk*".

Abandonment and Reclamation Costs

We will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of our projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of our approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial and, while the Corporation accrues a reserve in its financial statements for such costs in accordance with International Financial Reporting Standards, such accruals may be insufficient.

It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, we may determine it to be prudent or required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If we establish a reclamation fund, our liquidity and funds flow may be adversely affected.

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines if a licensee or permit holder is unable to satisfy its regulatory obligations. The implementation of or changes to the requirements of liability management programs may result in significant increases to the security that must be posted by licensees, increased and more frequent financial disclosure obligations or the denial of licence or permit transfers, which could impact the availability of capital to be spent by us, which could in turn materially adversely affect our business and financial condition. In addition, these liability management programs may prevent or interfere with our ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets.

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;
- 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;
- political uncertainty;
- environmental and Indigenous activism that may result in delays or cancellations of projects; 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. Due to these factors, we may 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.

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.

Industry Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration for, and the 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 materially and adversely affected.

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 and natural gas. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels 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, third party challenges to regulatory decisions or orders can reduce the efficiency of the regulatory regime, as the implementation of the decisions and orders may be delayed resulting in uncertainty and interruption to the business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

To conduct oil and natural gas operations, we require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licences, 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*".

Royalty Regimes

Governments in the jurisdictions in which we have assets may adopt new royalty regimes, or modify the existing royalty regimes, which may impact the economics of our projects. An increase in royalties will 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 to stimulate the production of oil and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing have resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity and 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, and/or third-party or governmental claims, and could increase our costs of compliance and doing business, as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions 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 result in us being unable to economically recover certain 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. For instance, significantly reduced mountain snowpack and below-average precipitation over the past number of months has led to extremely low reservoir levels and record-low river levels in certain areas of Alberta. As such, for the first time since 2001, Alberta's Drought Command Team has been authorized to negotiate water-sharing agreements with water licence holders, including in the Red Deer River, Bow River and Old Man River basins, to manage water use and mitigate the risks of drought. If we are unable to obtain water to use in our operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which ultimately would have a detrimental effect on our financial condition, results of operations, and funds flow.

In addition, we must dispose of the fluids produced from oil 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.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighbouring 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, 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 Fox Creek, Red Deer and Brazeau areas (collectively, the "Seismic Protocol Regions") initially in response to significant induced seismic activity in the Duvernay formation in Fox Creek. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude, which vary among the three regions. The reporting requirements include an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events and the suspension of operations, depending on the magnitude of an earthquake. Orders imposed by the AER in response to seismic events remain in effect as long as the AER deems them necessary. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, leading to continued monitoring by the AER. The AER may extend seismic protocols to other areas of the province if necessary, which may adversely affect our operations.

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

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 EOR 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 December 2027 and December 2034. Although we purchase CO_2 supplies under multi-year contracts, if thereafter such contacts 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 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 liabilities 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 fossil fuel combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and GHG emissions, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries, including Canada and the United States, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. At the 2021 United Nations Climate Change Conference, Canada made several pledges aimed at reducing Canada's GHG emissions and at the 2023 United Nations Climate Change Conference, Canada renewed its commitments to transitioning away from fossil fuels and further cutting GHG emissions. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations. See "*Industry Conditions – Climate Change Regulation*".

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting 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 and 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. Individuals, governmental 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, which may adversely affect our operations, the demand for and price of our securities and our cost of capital and access to the capital markets.

We are committed to report 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. Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, in June 2023 the International Sustainability Standards Board issued two new international sustainability disclosure standards with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. The Canadian Securities Administrators had previously published for comment Proposed National Instrument 51-107 – *Disclosure of Climate-Related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada. It is expected that the introduction of the new international standards will instruct how new Canadian sustainability disclosure standards are finalized. 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 – 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 we 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 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 Rising Interest Rates

Canada, the United States and other countries have recently experienced high levels of inflation, supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs and commodity prices, and additional government intervention through stimulus spending and additional regulations. These factors have increased our operating costs. 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 natural 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 at reasonable prices when required. 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.

In addition, many central banks, including the Bank of Canada and U.S. Federal Reserve, have taken steps to raise interest rates in an attempt to combat inflation. The rise in interest rates has impacted our borrowing costs. The increase in borrowing costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and funds flow. Rising interest rates could also result in a recession in Canada, the United States or other countries. A recession may have a negative impact on demand for oil and natural gas, causing a decrease in commodity prices. A decrease in commodity prices would immediately impact our revenues and funds flow and could also reduce drilling activity on our properties. It is unknown how long inflation will continue to impact the economies of Canada and the United States and how inflation and rising interest rates will impact oil and gas demand and commodity prices.

Asset Concentration

Our producing and undeveloped properties are geographically concentrated in Western Canada. Demand for and costs of personnel, equipment, power, services, and resources in Western Canada are high, which 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 and natural gas production volumes being below our forecasted production volumes. In addition, any such decrease in production volumes, or any significant increases in costs, could have a material adverse effect on our financial conditions, results of operations, funds flow and profitability.

As a result of this geographical 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, Indigenous rights claims, 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. Consequently, municipal and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production. 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 in 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 and interest 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 of funds available to fund our exploration and development activities, and 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, proceeds from asset sales 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 those affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including us, to access 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.

As a result of global economic and political volatility, we may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If 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 production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing Shareholders. Failure to obtain any financing necessary for our capital expenditure or acquisition plans may result in a delay in development of or production from 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. 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, the repurchase of Common Shares, the 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, physical sabotage or terrorist attacks. 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 and may divert the attention of management and key personnel from business operations. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack or sabotage, it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against such risks.

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.sedarplus.ca*.

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 Licences 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, be 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. Although there are no outstanding Indigenous and treaty rights claims currently affecting lands where we operate, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on our operations or pace of growth.

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, a recent British Columbia Supreme Court decision determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nation in northeast British Columbia breached that group's treaty rights. Recently, the Government of British Columbia and the First Nation came to an agreement relating to further industrial activities in the area. The developments in northeastern British Columbia relating to Indigenous rights may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts and associated risks of the decision on the Canadian oil and natural gas industry remains uncertain. See "*Industry Conditions – Indigenous Rights*".

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have introduced or passed similar legislation and have begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government are uncertain. Additional processes may be created and legislation associated with project development and operations may be amended or introduced, further increasing uncertainty with respect to project regulatory approval timelines and requirements. 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 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 (including with respect to ongoing assessments as described elsewhere in this Annual Information Form) whether by re-characterization of exploration and development expenditures or otherwise, such reassessments may have an impact on current and future taxes, penalties, and interest payable, which could have an adverse effect on our financial condition. See "*Legal Proceedings and Regulatory Actions – Reassessments*".

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 or other 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 our workforce. If we are unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

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.

The protection of customer, employee, and company data is also critical to our business. The regulatory environment in Canada surrounding information security and privacy is increasingly demanding, with the frequent imposition of new and constantly changing requirements. Certain legislation, including the *Personal Information Protection and Electronic Documents Act* in Canada, require documents to be securely destroyed to avoid identity theft and inadvertent disclosure of confidential and sensitive information. A significant breach of customer, employee, or company data could attract a substantial amount of media attention, damage our customer relationships and reputation, and result in fines or lawsuits. In addition, an increasing number of countries have introduced and/or increased enforcement of comprehensive privacy laws or are expected to do so. The continued emphasis on information security as well as increasing concerns about government surveillance may lead customers to request us to take additional measures to enhance security and/or assume higher liability under our contracts. As a result of legislative initiatives and customer demands, we may have to modify our operations to further improve data security. Any such modifications may result in increased expenses and operational complexity, and adversely affect our reputation, business, financial condition and results of operations.

We may fail to meet our emissions and/or other sustainability and climate targets

We are 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. Our ability to achieve our targets is subject to numerous risks and uncertainties, and our actions taken in implementing these objectives may also expose us to certain additional and/or heightened financial and operational risks.

A reduction in methane and Scope 1 and Scope 2 emissions is dependent on, among other things, our ability to deploy sufficient capital to fund the expenditures to implement the necessary operational changes required to achieve our targets; our ability to implement requisite operational changes; our ability to implement some or all of the technology necessary to efficiently and effectively achieve expected future results, including in respect of our methane and Scope 1 and Scope 2 emissions reduction targets, and the availability of requisite technological advances; the commercial viability and scalability of methane and other GHG emissions reduction strategies and related technology and products; and the development and execution of implementing strategies to meet our methane and Scope 1 and Scope 2 emissions reduction targets.

In the event that we are unable to implement our methane and Scope 1 and Scope 2 emissions reduction and/or other climate and sustainability strategies and technologies as planned or in the event that such strategies or technologies do not perform as expected, we may be unable to meet our methane and Scope 1 and Scope 2 emissions reduction targets or goals or other ESG, climate and sustainability targets on the current timelines, or at all. In addition, the cost associated with achieving our methane and Scope 1 and Scope 2 emissions reductions targets and other climate and sustainability targets could be significant, and could require significant capital expenditures and resources, potentially including the acquisition of technology, with the potential that the costs required to achieve our targets could differ from our original estimates and expectations, which differences may be material. The overall cost of investing in and implementing an emissions reduction strategy and technologies in furtherance of such strategies, and the resultant change in the deployment of our resources and focus, could have a material adverse effect on our business, financial condition, and results of operations. There is also a risk that some or all of the expected benefits and opportunities of achieving the various methane and Scope 1 and Scope

2 emissions reduction, climate and other sustainability goals, including as a result of a transition project or technology acquisition, may fail to materialize within the anticipated time periods or at all.

Failure to achieve our emissions, climate or sustainability targets could have a negative impact on our reputation, business, cash flows, results of operations, and on our access to, and cost of, capital.

Reputational Risk Associated with Our Operations

Our business, operations or financial condition may be negatively impacted by 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.

Forced or Child Labour in Supply Chains

In May 2023 *An Act to enact the Fighting Against Forced Labour and Child Labour in Supply Chains Act and to amend the Customs Tariff* was passed and came into force on January 1, 2024. Pursuant to the new legislation, any company that is subject to the reporting requirements, including us, is required to conduct certain due diligence on its supply chains and to file an annual report accordingly. While we are currently unaware of any forced or child labour in any of our supply chains, the increased scrutiny on the supply chains of Canadian companies could uncover the risk or existence of forced or child labour in a supply chain to which we have a connection, which could negatively impact our reputation.

Impacts of Pandemics

In the event of a global pandemic, countries around the world may close international borders and order the closure of institutions and businesses deemed non-essential. This could result in a significant reduction in economic activity in Canada and internationally along with a drop in demand for oil and natural gas. Any reduction in economic activity in certain countries resulting from outbreaks, government-imposed lockdowns and other restrictions could have a negative effect on demand for oil and natural gas and could also aggravate the other risk factors identified herein.

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, October 27, 2021, March 15, 2022 and August 30, 2023 and 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 and amendments are available on our SEDAR+ profile at *www.sedarplus.ca*. 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.

Reassessments

In 2023, Whitecap received reassessments from the Canada Revenue Agency (the "CRA") and the Alberta Tax and Revenue Administration ("ATRA") for a former subsidiary that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2018 and 2019.

Whitecap remains confident in the appropriateness of its tax filing position and intends to vigorously defend it. As such, Whitecap has not recognized any provision in its audited annual consolidated financial statements with respect to the reassessments.

Whitecap filed a notice of objection for each CRA and ATRA reassessment and paid 50 percent of the reassessed taxes, interest, and penalties as a deposit to the CRA ($65.3 million) and the ATRA ($17.7 million). Whitecap subsequently filed an appeal directly to the Tax Court of Canada. Whitecap currently estimates that the ultimate resolution of the matter may take two to four years. If Whitecap is ultimately successful in defending its position, then any taxes, interest and penalties paid to the CRA and the ATRA would be refunded plus interest. If Whitecap is unsuccessful, then any remaining taxes payable plus interest and any penalties would have to be remitted by Whitecap.

By way of background, Whitecap acquired a private entity in 2014 that held an interest in certain oil and natural gas assets, and which had accrued non-capital losses in its business. The reassessments seek to disallow the deduction of approximately $494 million of these non-capital losses under the *Income Tax Act* (Canada) and corresponding provincial legislation for the years 2018 and 2019.

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, 2023. 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.sedarplus.ca* 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, 2023 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) "*Thanh C. Kang*"
Thanh C. Kang
Senior Vice President & Chief Financial Officer

(signed) "*Daryl H. Gilbert*"
Daryl H. Gilbert
Director and Member of the Reserves Committee and the Health, Safety and Environment Committee

February 20, 2024

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, 2023. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2023, 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, 2023, 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, 2023	Canada	-	14,419,442	-	14,419,442

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 8, 2024.

"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; internal control systems, including identifying, monitoring and mitigating business risks (including information security risks); 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 in meeting 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 independent members of the Board. 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 (including information security 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 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 (e.g. hedging, litigation, information security, 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 information security (including cybersecurity) policies and procedures and receive reports from management each quarter on its activities to protect Whitecap from information security (including 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 matter to be decided upon 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 24, 2023.

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