ANNUAL INFORMATION FORM

2023

February 28, 2024

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APPENDICES:

SELECTED TERMS

Capitalized terms in this document have the meanings set forth below:

Entities

Baytex or the **Corporation** means Baytex Energy Corp., a corporation incorporated under the ABCA.

Baytex Energy means Baytex Energy Ltd., a corporation amalgamated under the ABCA.

Baytex Partnership means Baytex Energy Limited Partnership, a limited partnership, the partners of which are Baytex Energy and Baytex Energy (LP) Ltd.

Baytex USA means Baytex Energy USA, Inc., a corporation organized under the laws of the State of Delaware.

Board or **Board of Directors** means the board of directors of Baytex.

CRA means the Canada Revenue Agency.

NYSE means New York Stock Exchange.

OPEC means the Organization of the Petroleum Exporting Countries.

OPEC+ means OPEC plus a number of other oil exporting countries, including Russia.

Ranger means Ranger Oil Corporation.

Ranger Merger means the acquisition of all of the issued and outstanding Class A common stock of Ranger by Baytex by way of merger of Ranger and Ranger Sub.

Ranger Sub means Nebula Merger Sub, LLC, being an indirect wholly owned subsidiary of Baytex.

SEC means the United States Securities and Exchange Commission.

Shareholders mean the holders from time to time of Common Shares.

subsidiary has the meaning ascribed thereto in the *Securities Act* (Ontario) and, for greater certainty, includes all corporations, partnerships and trusts owned, controlled or directed, directly or indirectly, by us.

TSX means the Toronto Stock Exchange.

we, **us** and **our** means Baytex and all its subsidiaries on a consolidated basis unless the context requires otherwise.

Securities and Other Terms

2014 Debt Indenture means the indenture, as amended, among Baytex, as issuer, certain of its subsidiaries, as guarantors, and Computershare Trust Company, N.A., as indenture trustee, dated June 6, 2014, which was terminated and discharged as of June 28, 2022.

2020 Debt Indenture means the indenture among Baytex, as issuer, certain of its subsidiaries, as guarantors, and Computershare Trust Company, N.A., as indenture trustee, dated February 5, 2020.

2023 Debt Indenture means the indenture among Baytex, as issuer, certain of its subsidiaries, as guarantors, and Computershare Trust Company, N.A., as indenture trustee, dated April 27, 2023.

2024 Notes means the 5.625% senior unsecured notes due June 1, 2024 issued by Baytex pursuant to the 2014 Debt Indenture which were redeemed as of June 2, 2022.

2027 Notes means the 8.750% senior unsecured notes due April 1, 2027 issued by Baytex pursuant to the 2020 Debt Indenture.

2030 Notes means the 8.500% senior unsecured notes due April 30, 2030 issued by Baytex pursuant to the 2023 Debt Indenture.

ABCA means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

AIF means this annual information form of the Corporation dated February 28, 2024 for the year ended December 31, 2023.

Baytex Annual 2023 MD&A means Baytex's annual MD&A dated February 28, 2024 for the year ended December 31, 2023.

Canadian GAAP means generally accepted accounting principles in Canada, which are consistent with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Common Shares means the common shares of Baytex.

Credit Facilities means our US$1.1 billion secured covenant-based revolving credit facilities with a syndicate of financial institutions.

CSS means cyclic steam stimulation.

GHG means greenhouse gas.

MD&A means management's discussion and analysis of operating and financial results.

NCIB normal course issuer bid.

Preferred Shares means preferred shares of Baytex.

SAGD means steam-assisted gravity drainage.

Senior Notes means, collectively, the 2027 Notes and the 2030 Notes.

Tax Act means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5th Supp.), as amended, including the regulations promulgated thereunder, as amended from time to time.

<u>Independent Engineering</u>

Baytex Reserves Report means the report of McDaniel dated February 1, 2024 entitled ‘‘Baytex Energy Corp., Evaluation of Petroleum Reserves, Based on Forecast Prices and Costs, As of December 31, 2023’’.

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.

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants.

NI 51-101 means National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators.

Reserves Definitions

Gross means:

(a) in relation to our interest in production and reserves, our 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.

Net means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, 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.

Forecast Prices and Costs are 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 Baytex is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

Reserves and Reserve Categories

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

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

(b) the use of established technology; and

(c) specified economic conditions, which are generally accepted as being reasonable (being the Forecast Prices and Costs used in the estimate).

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

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

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves 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 qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Development and Production Status

Each of the reserves 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 the following categories:

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.

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, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved or probable) to which they are assigned.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
MMbbl	million barrels
NGL	natural gas liquids
bbl/d	barrels per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units

Other

API	the measure of the density or gravity of liquid petroleum products as compared to water		
BOE or boe	barrel of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one bbl of oil. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**		
boe/d	barrels of oil equivalent per day	MEH	Magellan East Houston
Mboe	thousand barrels of oil equivalent	MSW	Mixed Sweet Blend
MMboe	million barrels of oil equivalent	WTI	West Texas Intermediate
NYMEX	the New York Mercantile Exchange	WCS	Western Canadian Select
AECO	the natural gas storage facility located at Suffield, Alberta	$ Million	millions of dollars
		$000s	thousands of dollars

CONVERSIONS AND CONVENTIONS

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbl	Cubic metres	0.159
Cubic metres	Bbl	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.400
Hectares	Acres	2.500

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings in this AIF as in NI 51-101. Unless otherwise indicated, references in this AIF to "$" or "dollars" are to Canadian dollars and references to "US$" are to United States dollars. All financial information contained in this AIF has been presented in Canadian dollars in accordance with Canadian GAAP. All operational information contained in this AIF relates to our consolidated operations unless the context otherwise requires.

SPECIAL NOTES TO READER

Forward-Looking Statements

In the interest of providing our Shareholders and potential investors with information about us, including management's assessment of our future plans and operations, certain statements in this AIF are "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995* and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "**forward-looking statements**"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this AIF speak only as of the date hereof and are expressly qualified by this cautionary statement.

Specifically, this AIF contains forward-looking statements relating to, but not limited to: our business strategies, plans and objectives; our 2024 guidance for exploration and development expenditures and production; our five-year outlook including expected production, production growth and annual capital spending; our intentions to continue allocating our annual free cash flow[(1)] to shareholder returns through share buybacks and debt reduction; our dividend policy and our intentions to continue paying dividends on a consistent basis and the timing thereof; our goal of building value by developing our assets and completing selective acquisitions; our belief that our asset base is somewhat unique; our commitment to restoring our 2020 end-of-life well inventory to zero and the anticipated timing thereof; our ability to mitigate and adapt to changes in oil and gas prices; that we are competitive with similarly situated companies; that we do not expect to be materially affected by the renegotiation or termination of contracts in 2024; development plans for our properties; the expected benefits and continued performance of our increased Eagle Ford scale as a result of the Merger; undeveloped lease expiries; when we expect to pay material income taxes; our working interest production volume for 2024 based on the future net revenue disclosed in our reserves; our risk management policy's ability to manage our exposure to fluctuations in commodity prices, foreign exchange and interest rates; that we market our production with attention to maximizing value and counterparty performance; the development plans for our undeveloped reserves; our future abandonment and reclamation liabilities; our funding sources for development capital expenditures and our expectations that interest or other funding costs would not make development of any of our properties uneconomic; the impact of existing and proposed governmental and environmental regulation; our assessment of our tax filing position for the years 2011 through 2015; our expectations regarding the timing of receiving a judgement with respect to our notices of appeal with the Tax Court of Canada; and our expectations regarding timing should we be unsuccessful at the Tax of Court of Canada with respect to the aforementioned notices of appeal.

In addition, there are forward-looking statements in this AIF under the headings "General Description of Our Business" and "Statement of Reserves Data" as to our reserves, including with respect thereto, the future net revenues from our reserves, pricing and inflation rates, future development costs, the development of our proved undeveloped reserves and probable undeveloped reserves, future development costs, reclamation and abandonment obligations, tax horizon, exploration and development activities and production estimates.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; that we will have sufficient financial resources in the future to provide shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the risk of an extended period of low oil and natural gas prices; risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; current or future controls, legislation or regulations; restrictions on or access to water or other fluids; public perception and its influence on the regulatory regime; new regulations on hydraulic fracturing; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks associated with a third-party operating our Eagle Ford properties; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; adverse results of litigation; that our Credit Facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with expansion into new activities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Corporation and its directors and officers; variability of share buybacks and dividends; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. Readers should also carefully consider the matters discussed under the heading "Risk Factors" in this AIF.

The above summary of assumptions and risks related to forward-looking statements in this AIF has been provided in order to provide Shareholders and potential investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes. There is no representation by us that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and we do not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

The Corporation's future shareholder distributions, including but not limited to the payment of dividends and the future acquisition by the Corporation of Common Shares pursuant to a share buyback (including through its NCIB), if any, and the level thereof is uncertain. Any decision to pay dividends on the Common Shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith) or acquire Common Shares pursuant to a share buyback will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Corporation's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions (including covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future, including the terms of the Credit Facilities) and satisfaction of the solvency tests imposed on the Corporation under applicable corporate law. There can be no assurance of the number of Common Shares that the Corporation will acquire pursuant to a share buyback, if any, in the future. Further, the payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely.

This AIF contains information that may be considered a financial outlook under applicable securities laws about the Corporation's potential financial position, including, but not limited to, our 2024 guidance for development expenditures; our five-year outlook including our expected annual capital spending; our intentions of continuing to allocate our annual free cash flow(1) to shareholder returns through a share buyback and debt reduction; our intentions to continue paying dividends; and when we expect to pay material income taxes, all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Corporation and the resulting financial results will vary from the amounts set forth in this AIF and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Corporation undertakes no obligation to update such financial outlook, whether as a result of new information, future events or otherwise. The financial outlook contained in this AIF was made as of the date of this AIF and was provided for the purpose of providing further information about the Corporation's potential future business operations. Readers are cautioned that the financial outlook contained in this AIF is not conclusive and is subject to change.

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. See "Specified Financial Measures" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. The Baytex Annual 2023 MD&A are available on SEDAR+ at www.sedarplus.com.

New York Stock Exchange

As a Canadian corporation listed on the NYSE, we are not required to comply with most of the NYSE's corporate governance standards and, instead, may comply with Canadian corporate governance practices. We are, however, required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on our website at www.baytexenergy.com, we are in compliance with the NYSE corporate governance standards.

Foreign Private Issuer Status

The Corporation continues to qualify as a foreign private issuer for the purposes of its U.S. securities filings based on the most recent assessment performed as at June 30, 2023. The Corporation is required to reassess this conclusion annually, at the end of the second quarter. See "*Risk Factors – The Corporation could lose its status as a "foreign private issuer*" in the United States, which may result in additional compliance costs and restricted access to capital markets.

Access to Documents

Any document referred to in this AIF and described as being accessible on the SEDAR+ website at *www.sedarplus.com* or on EDGAR at *www.sec.gov* (including those documents referred to as being incorporated by reference in this AIF) may be obtained free of charge from us at Suite 2800, Centennial Place, East Tower, 520 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3.

CORPORATE STRUCTURE

General

Baytex Energy Corp. was incorporated on October 22, 2010 pursuant to the provisions of the ABCA. Baytex is the successor to the business of Baytex Energy Trust, which was transitioned to Baytex on December 31, 2010.

Our head and principal office is located at Suite 2800, Centennial Place, East Tower, 520 – 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3. Our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, Canada, T2P 1G1. The Common Shares are currently traded on the TSX and the NYSE under the symbol "BTE".

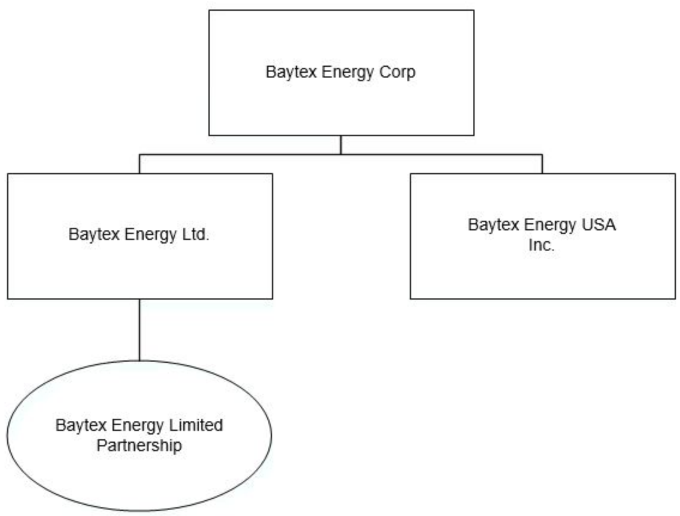
Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation, continuance, formation or organization of our material subsidiaries either, direct or indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Jurisdiction of Incorporation/ Formation
Baytex Energy Ltd.	100%	Alberta
Baytex Energy USA, Inc.	100%	Delaware
Baytex Energy Limited Partnership	100%	Alberta

Our Organizational Structure

The following simplified diagram shows the inter-corporate relationships among us and our material subsidiaries as of the date hereof.



DEVELOPMENT OF OUR BUSINESS

Developments in the Past Three Years

2021

2021 saw significant improvement in commodity markets. Demand for oil and gas recovered from the impacts of the Covid-19 pandemic and supply increases were limited as a result of the agreement between OPEC+ to limit production and the capital discipline of North American shale producers who did not pursue significant production growth. The price for WTI averaged US$67.92/bbl for the year.

In April of 2021 we announced an exciting exploration discovery in the Clearwater oil play in Peace River along with a five-year outlook (2021-2025) that highlights our financial and operational sustainability and meaningful free cash flow generation capability. As a result of improved commodity prices and the additional activity at our Clearwater discovery, both our annual production guidance and capital budget were increased. Production for the year averaged 80,156 boe/d, which was comprised of 15,710 bbl/d of light and medium crude oil, 20,449 bbl/d of heavy crude oil, 1,739 bbl/d of bitumen, 15,291 bbl/d of tight oil, 12,032 bbl/d of NGL, 40,051 mcf/d of shale gas and 49,555 mcf/d of conventional natural gas, and exploration and development expenditures were $313 million. During the year our net debt[1] was reduced by $438 million to $1.4 billion and in connection with this debt reduction we repurchased and early redeemed US$200 million principal amount of 2024 Notes.

On December 1, 2021 we announced our anticipated 2022 exploration and development expenditures range of $400-450 million designed to generate average annual production of 80,000-83,000 boe/d. We also announced an update to our five-year outlook that optimizes production in the 85,000 to 90,000 boe/d range and generates annual production growth of 2% to 4% with annual capital spending of $400 to $475 million from 2022 to 2025.

2022

Commodity prices were strong throughout the year, they increased during the first half of the year due to uncertainty surrounding global energy security and then retreated as a result of concerns over high inflation and slowing economic activity. The price for WTI averaged US$94.23/bbl for the year.

In February 2022, as a result of Baytex's significantly improved financial position, we announced an intent to allocate approximately 25% of annual free cash flow[2] to direct shareholder returns through a share buyback with the remainder of free cash flow continuing to be allocated to debt reduction.

On April 1, 2022 we amended our Credit Facilities to, among other things, extend the term by two years to April 2026 and increase the aggregate principal amount available thereunder to US$850 million.

On May 2, 2022 we announced the approval of an NCIB allowing us to purchase up to 56,300,143 Common Shares during the 12-month period commencing May 9, 2022 and ending May 8, 2023. During the year ended December 31, 2022 we repurchased 24.3 million Common Shares at an average price of $6.54 per Common Share. In connection with the NCIB, we entered into entered into an automatic share purchase plan with RBC Dominion Securities Inc. ("RBC") allowing RBC to purchase Common Shares under the NCIB when the Corporation would ordinarily not be permitted to purchase Common Shares due to regulatory restrictions and customary self-imposed blackout periods.

On June 1, 2022 we redeemed and canceled our remaining US$200 million of 2024 Notes. During the year we also made open market repurchases of US$90 million of 2027 Notes.

Effective November 4, 2022 the Board of Directors appointed Mr. Eric Greager to the position of President and Chief Executive Officer and as a Director, replacing Mr. LaFehr. Mr. LaFehr concurrently resigned as a Director, but remained as an advisor to the Board and to the President and Chief Executive Officer until February of 2023.

On November 17, 2022 we announced that Mr. Chad Kalmakoff was promoted to Chief Financial Officer of the Corporation from his previous position of Vice President, Finance, replacing Mr. Rodney Gray. Mr. Rodney Gray concurrently resigned as Executive Vice President and Chief Financial Officer.

On December 7, 2022 we announced our anticipated 2023 exploration and development expenditures range of $575-650 million designed to generate average annual production of 86,000-89,000 boe/d. We also announced that once the Corporation's net debt[1] decreased to $800 million we would increase direct shareholder returns to 50% of free cash flow[2] and an ultimate debt target.

2023

Oil prices were lower in 2023 as a result of global supply growth which resulted in a more balanced crude market relative to 2022 when prices were elevated as the global supply shortfall was exacerbated by uncertainty related to Russian supply. The price for WTI averaged US$77.62/bbl for the year.

On February 8, 2023 the Board of Directors appointed Ms. Angela S. Lekatsas as a Director and announced that Mr. Gregory Melchin did not intend to stand for election at the next annual meeting of shareholders.

On February 23, 2023 the Common Shares commenced trading on the NYSE.

On February 28, 2023 Baytex announced its intention to acquire Ranger by way of the Merger. The Merger was completed on June 20, 2023 pursuant to the agreement and plan of merger dated February 27, 2023, as amended from time to time, between Baytex, Ranger and Ranger Sub. As consideration under the Merger, Baytex issued approximately 311.4 million Common Shares and paid $732.8 million in cash to the former security holders of Ranger. Additionally, Baytex assumed CAD $1.1 billion of Ranger's net debt(1). The cash portion of the Merger was funded with the Corporation's expanded US$1.1 billion revolving Credit Facility, a US$150 million two-year term loan facility and the net proceeds from the issuance of US$800 million 2030 Notes. The term loan facility was fully repaid and cancelled in August of 2023.

The Merger increased our Eagle Ford scale and provided an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford. Production from the Ranger assets is approximately 80% weighted towards high netback light oil and liquids.

In conjunction with closing of the Merger, we increased direct shareholder returns to 50% of free cash flow(2), which allowed us to increase the value of our share buyback program and introduce a dividend. The remainder of our free cash flow(2) was allocated to debt reduction. On June 23, 2023 we announced the renewal of our NCIB allowing us to purchase up to 68,417,028 Common Shares during the 12-month period commencing June 29, 2023 and ending June 28, 2024. In 2023, we returned approximately $260 million to shareholders through our share buyback program and dividends. As at December 31, 2023, we had repurchased 40.5 million Common Shares under the NCIB for approximately $222 million, representing 4.7% of our issued and outstanding Common Shares, at an average price of $5.48 per Common Share. In addition, during 2023, we declared two quarterly dividends of $0.0225 per Common Share, totaling approximately $38 million.

On closing of the Merger, Jeffrey E. Wojahn and Tiffany ("T.J.") Thom Cepak were appointed to the Board of Directors, providing continuity and experience with the Ranger business and expertise in U.S. regulatory and operating matters.

On November 27, 2023, we announced that we had entered into a definitive agreement to sell certain of our Viking assets located at Forgan and Plato in southwest Saskatchewan (the "**Sold Viking Assets**"), effective October 1, 2023. On December 11, 2023, we completed the divestiture of the Sold Viking Assets for proceeds of $159.7 million, including closing adjustments. Proceeds from the sale were applied against our Credit Facilities. Production from the Sold Viking Assets at the time of the sale was approximately 4,000 boe/d (100% light and medium crude oil).

(1) Capital management measure. See "Specified Financial Measures" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. The Baytex Annual 2023 MD&A is available on SEDAR+ at www.sedarplus.com.

(2) Specified financial measure that does not have any standardized meaning prescribed by International Financial Reporting Standards ("**IFRS**") and may not be comparable with the calculation of similar measures presented by other entities. See "*Specified Financial Measures*" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. The Baytex Annual 2023 MD&A is available on SEDAR+ at www.sedarplus.com.

On December 6, 2023 we announced our anticipated 2024 exploration and development expenditures range of $1.2 to $1.3 billion, which is designed to generate average annual production of 150,000-156,000 boe/d.

Significant Acquisitions

The only significant acquisition completed by the Corporation in the year ended December 31, 2023 was the Merger. See "*Development of our Business – Developments in the Past Three Years – 2023*" above for a summary of the Merger. On June 27, 2023, the Corporation filed a Form 51-102F4 – *Business Acquisition Report* in respect of the Merger, which is available on SEDAR+ at www.sedarplus.com.

DESCRIPTION OF OUR BUSINESS

Overview

We are engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and the Eagle Ford in the United States. Approximately 85% of our production is weighted toward crude oil and NGLs. The Corporation and its predecessors have been in business for more than 30 years and our operating teams are well established with a track record of technical proficiency and operational success. Throughout our history we have endeavoured to add value by developing our assets and completing selective acquisitions and divestitures.

Competitive Conditions

Baytex is in the oil and natural gas industry, which is highly competitive and capital intensive, and many competitors have financial resources which exceed our own. Baytex competes with other companies for all of its business inputs, including development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. Our asset base is somewhat unique in that we have significant oil and gas assets in both Canada and the United States; however, on the whole, our competitive position is similar to that of other oil and natural gas producers of a similar size and production profile. See *Industry Conditions* and *Risk Factors.*

Environmental and Social Policies

We have an active program to monitor and comply with all environmental laws, rules and regulations applicable to our operations. Our policies require that all employees and contractors report all breaches or potential breaches of environmental laws, rules and regulations to our senior management and all applicable governmental authorities. Any material breaches of environmental law, rules and regulations must be reported to the Board of Directors. Our Health, Safety and Environment Policy is available on our website at www.baytexenergy.com.

In recognition of the importance of our Health, Safety and Environment Policy and targets, including our GHG reduction target, the mandate for the reserves and sustainability committee of the Board of Directors has been given specific responsibility for the "oversight and monitoring of the Corporation's performance related to health, safety, environment, climate and other sustainability matters."

We have published a Corporate Responsibility Report since 2012 and published our seventh report in July of 2023. This report details our efforts and performance with respect to people, the environment, our community and stakeholders, and responsible business practices. Over this time period our reporting standards and objectives have developed significantly. Our most recent report which outlined our achievements in 2022 included the following highlights:

- Reduced our corporate GHG emissions intensity by 59% from our 2018 baseline, achieving 90% of our goal of reducing our GHG emissions intensity 65% by 2025.
- Completed 379 well abandonments in 2022, the most in our history as we work towards restoring our 2020 end-of-life well inventory of 4,500 wells to zero by 2040.

- Met our Board gender diversity target by having women make up 30% of our Board prior to our 2023 Annual General Meeting.

At the same time, we also released our second Task Force on Climate-Related Financial Disclosures report.

See "*Industry Conditions*" and "*Risk Factors*".

Cyclical and Seasonal Factors

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 by closely monitoring commodity markets, implementing our risk management programs and by maintaining financial liquidity. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes. See "*Industry Conditions*" and "*Risk Factors*".

The level of activity in the oil and gas industry is dependent on access to areas where operations are conducted. In Canada, seasonal weather variations, including spring break-up which occurs annually, affects access in certain circumstances. In Canada and the United States, unexpected adverse weather conditions, such as flooding, extreme cold weather, heavy snowfall, heavy rainfall and forest fires may restrict the Corporation's ability to access its properties. See "*Industry Conditions*" and "*Risk Factors*".

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspects of our business will be materially affected during the remainder of 2024 by the renegotiation or termination of any contracts to which we are a party.

Personnel

As at December 31, 2023, Baytex had 158 employees in our Calgary office, 70 employees in our Houston office, 65 employees in our Canadian field operations and 74 employees in our US field operations.

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. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2023 and production information represents average working interest production for the year ended December 31, 2023. All of our properties are located onshore.

Eagle Ford - Texas

Our Eagle Ford assets are located in the Eagle Ford shale of South Texas and are comprised of operated assets and non-operated assets. Our operated assets were acquired through the Ranger Merger and are comprised of operated working interests in approximately 190,939 (166,192 net) acres located principally in the Gonzales, Lavaca, Fayette and Dewitt counties with an average working interest of approximately 88%. Our non-operated assets include working interests in approximately 78,212 (19,931 net) acres, comprised of four areas of mutual interest principally located in Karnes County (Sugarloaf, Longhorn, Ipanema and Excelsior) with an average working interest of approximately 25%. Our non-operated position is operated by an operating subsidiary of Marathon Oil Corporation (NYSE: MRO), pursuant to the terms of industry-standard joint operating agreements, joint venture agreements with non-AMI working interest holders where wells produce from AMI and non-AMI lands as well as negotiated agreements with Marathon and other working interest owners related to facilities, marketing and supplemental development. Production from our Eagle Ford assets occurs from the hydraulic fracturing of horizontal wells.

During 2023, production from the Eagle Ford assets averaged approximately 60,997 boe/d, comprised of 49,905 bbl/d of light and medium crude oil (including condensate and NGL) and 66,556 Mcf/d of shale gas. During this period, Baytex participated in the completion of 83 (42.3 net) wells, resulting in 58 (25.8 net) oil wells and 25 (16.5 net) natural gas wells. As at December 31, 2023, our proved plus probable reserves were 418 million boe (292 million proved; 126 million probable).

As at December 31, 2023, the undeveloped land base associated with the Eagle Ford assets consisted of 35,172 net acres

Peace River - Alberta

In the Peace River area of northwest Alberta we produce heavy gravity crude oil and natural gas from the Bluesky formation and heavy gravity crude oil from the Spirit River (a Clearwater equivalent) formation. The core of our developing Clearwater play is located on the Peavine Métis settlement. Production in the area occurs through primary and polymer flooding recovery methods. During 2023, production from the area averaged approximately 25,537 boe/d, comprised of 23,608 bbl/d of heavy crude oil, 53 bbl/d of NGL and 11,258 Mcf/d of conventional natural gas. In 2023, Baytex drilled 36 (36.0 net) horizontal multi-lateral wells in this area. As at December 31, 2023, we had proved plus probable reserves of 54 million boe (33 million proved; 22 million probable).

Baytex held approximately 284,980 net undeveloped acres in this area as at December 31, 2023.

Lloydminster - Alberta and Saskatchewan

Our Lloydminster assets consist of several geographically dispersed heavy crude oil operations that include primary and thermal production. In some cases, Baytex's heavy crude oil reservoirs are water flooded and polymer flooded. In 2023, production averaged approximately 12,091 boe/d, which was comprised of 10,105 bbl/d of heavy crude oil, 1,747 bbl/d of bitumen, 22 bbl/d of light and medium crude oil, and 1,298 Mcf/d of conventional natural gas. In 2023, Baytex drilled 34 (32.2 net) oil wells in this area. As at December 31, 2023, we had proved plus probable reserves of 84 million boe (25 million proved; 59 million probable).

We held approximately 179,016 net undeveloped acres in this area at December 31, 2023.

Duvernay - Alberta

Baytex holds a large 100% working interest land position in the East Duvernay resource play in central Alberta. Production in the area occurs from the hydraulic fracturing of horizontal wells. In 2023, production averaged 3,719 boe/d, comprised of 3,079 bbl/d of light crude oil and NGL and 3,840 Mcf/d of conventional natural gas. During 2023, Baytex drilled 6 (6.0 net) oil wells. As at December 31, 2023, we had proved plus probable reserves of 49 million boe (23 million proved; 26 million probable) and net undeveloped lands of approximately 91,844 net acres.

Viking - Alberta and Saskatchewan

Our Viking assets are located in the greater Dodsland area in southwest Saskatchewan and in the Esther area of southeastern Alberta. These assets were acquired through a business combination with Raging River Exploration Inc. in 2018 and produce light oil from the Viking formation. Production in the area occurs primarily from the hydraulic fracturing of horizontal wells. In some areas, reservoirs are placed under waterflood. In 2023, the Viking assets produced 15,295 boe/d, comprised of 13,323 bbl/d of light and medium crude oil and NGL and 11,834 Mcf/d of conventional natural gas. These assets are characterized by shallow wells with short cycle times and a manufacturing approach to development. In 2023, Baytex completed 148 (140.8 net) oil wells. As at December 31, 2023 we had proved plus probable reserves of 46 million boe (29 million proved; 17 million probable). On December 11, 2023, we completed the divestiture of the Sold Viking Assets located at Forgan and Plato in Southwest Saskatchewan for proceeds of $159.7 million, including closing adjustments. Production from the Sold Viking Assets at the time of the sale was approximately 4,000 boe/d (100% light and medium crude oil), represented approximately 25% of our Viking production at the time of sale. The Sold Viking Assets were geographically separated from our core position.

The undeveloped land base associated with the retained Viking assets consisted of 77,732 net acres at December 31, 2023.

Average Production

The following table indicates our average daily production from our principal properties for the year ended December 31, 2023.

	Heavy Crude Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Crude Oil (bbl/d)	Tight Oil (bbl/d)	NGL[(1)] (bbl/d)	Shale Gas (Mcf/d)	Conventional Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy								
Peace River	23,608	—	—	—	53	—	11,258	25,537
Lloydminster	10,105	1,747	22	—	—	—	1,298	12,091
Total	33,713	1,747	22	—	53	—	12,556	37,628
Canada - Light								
Viking	—	—	13,078	—	245	—	11,834	15,295
Duvernay	—	—	—	1,881	1,198	3,840	—	3,719
Remaining properties	—	—	594	—	715	—	19,224	4,514
Total	—	—	13,672	1,881	2,158	3,840	31,058	23,528
United States								
Eagle Ford	—	—	—	35,908	13,997	66,556	—	60,997
Grand Total	**33,713**	**1,747**	**13,694**	**37,789**	**16,208**	**70,396**	**43,614**	**122,153**

Note:

(1) Includes condensate.

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2023.

($000s)	Canada	United States	Total
Property acquisition costs			
Proved properties	1,556	18,891	20,447
Unproved properties	18,467	—	18,467
Property disposition	(160,256)	—	(160,256)
Total Property acquisition costs, net	(140,233)	18,891	(121,342)
Development Costs [1]	463,198	549,589	1,012,787
Exploration Costs [2]	—	—	—
Total	322,965	568,480	891,445

Notes:

(1) Development and facilities expenditures.

(2) Cost of land, geological and geophysical capital expenditures.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2023.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	999	871.2	1,160	685.0	124	71.1	241	163.5
BC	—	—	—	—	—	—	—	—
Saskatchewan	2,577	2,311.4	1,520	1,481.5	75	38.3	190	174.4
Texas	1,576	893.0	6	4.0	421	162.0	3	2.0
Total	5,152	4,075.6	2,686	2,170.5	620	271.4	434	339.9

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2023.

	Undeveloped Acres	
	Gross	Net
Alberta	677,091	548,508
Saskatchewan	231,220	178,673
Texas	60,212	35,172
Total	968,523	762,353

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2023. None of these undeveloped properties have high expected development or operating costs or contractual sales obligations to produce and sell at substantially lower prices than could be realized under normal market conditions.

We estimate the value of our net undeveloped land holdings at December 31, 2023 to be approximately $248 million, as compared to $166 million as at December 31, 2022. This estimate includes undeveloped land holdings added during 2023 from the Ranger Merger. This internal evaluation generally represents the estimated replacement cost of our undeveloped land and excludes approximately 47,558 net acres of our undeveloped land that we expect to expire on or before December 31, 2024. In determining replacement cost, we analyzed land sale prices paid at provincial crown land sales for properties in the vicinity of our undeveloped land holdings over the preceding three years.

Tax Horizon

When forecasted using the commodity price forecasts and inflation rates as of January 1, 2024 used to prepare the Reserves Report Baytex does not expect to pay material cash income taxes prior to 2026 in the U.S. and 2027 in Canada.

Despite this tax horizon, Baytex is subject to other taxes, such as taxes related to the repatriation of foreign earnings, certain U.S. state taxes, global minimum taxes, capital taxes and taxes on share buy backs (together, the “Other Taxes”).

Other Taxes amounted to $14 million in 2023 or 1% of EBITDA(1). Baytex forecasts that Other Taxes will average 2% of EBITDA during 2024 and 2025 and that income and Other Taxes combined will increase as a percentage of EBITDA from 2026 onwards, averaging 10 - 15% once available non-capital loss pools are fully utilized, and the full tax horizon is reached.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2023.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil Wells	—	—	225	217.2	225	217.2
Natural Gas Wells	—	—	—	—	—	—
Stratigraphic Test Wells	—	—	—	—	—	—
Service Wells	—	—	—	—	—	—
Dry Holes	—	—			—	—
Total	—	—	225	217.2	225	217.2
UNITED STATES						
Oil Wells	—	—	60	23.0	60	23.0
Natural Gas Wells	—	—	18	13.1	18	13.1
Stratigraphic Test Wells	—	—	—	—	—	—
Service Wells	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total	—	—	78	36.1	78	36.1

(1) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ending December 31, 2024, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "*Statement of Reserves Data - Disclosure of Reserves Data*".

	Heavy Crude Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Crude Oil (bbl/d)	Tight Oil (bbl/d)	NGL (bbl/d)[1]	Shale Gas (Mcf/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
CANADA								
Total Proved	27,541	2,155	10,079	2,602	2,536	5,967	35,476	51,820
Total Proved plus Probable	32,123	2,580	10,940	2,773	2,744	6,467	38,326	58,626
UNITED STATES								
Total Proved	—	—	—	46,994	22,092	100,069	—	85,765
Total Proved plus Probable	—	—	—	48,485	22,821	103,081	—	88,486
TOTAL								
Total Proved	27,541	2,155	10,079	49,596	24,629	106,036	35,476	137,585
Total Proved plus Probable	32,123	2,580	10,940	51,258	25,565	109,549	38,326	147,112

Note:

(1) Includes condensate.

The Eagle Ford property is the only property that accounts for 20% or more of the estimated 2024 production volumes. Estimated 2024 production volumes for the Eagle Ford property is 85,765 boe/d on a total proved basis and 88,486 boe/d on a total proved plus probable basis.

Production History

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

	Three Months Ended				Year Ended
	Dec. 31, 2023	Sep. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2023
Average Sales Volume [1]					
CANADA					
Light and Medium Crude Oil (bbl/d)	11,208	14,563	13,831	15,213	13,695
Heavy Crude Oil (bbl/d)	37,336	34,030	31,204	32,222	33,713
Bitumen (bbl/d)	2,233	1,175	1,617	1,969	1,747
Tight Oil (bbl/d)	2,803	2,960	672	1,060	1,881
NGL (bbl/d) [2]	3,069	2,219	1,542	2,000	2,210
Total liquids (bbl/d)	56,649	54,947	48,866	52,464	53,246
Shale Gas (Mcf/d)	6,748	3,996	1,946	2,623	3,840
Conventional Natural Gas (Mcf/d)	41,825	46,061	40,097	46,497	43,614
Total (boe/d)	64,744	63,289	55,874	60,651	61,157
UNITED STATES					
Tight Oil (bbl/d)	54,430	56,458	18,686	13,381	35,908
NGL (bbl/d) [2]	21,774	17,567	9,210	7,237	13,997
Total liquids (bbl/d)	76,204	74,025	27,896	20,618	49,905
Shale Gas (Mcf/d)	116,548	79,722	35,946	32,946	66,556
Total (boe/d)	95,629	87,311	33,887	26,109	60,997
TOTAL					
Light and Medium Crude Oil (bbl/d)	11,208	14,563	13,831	15,213	13,695
Heavy Crude Oil (bbl/d)	37,336	34,030	31,204	32,222	33,713
Bitumen (bbl/d)	2,233	1,175	1,617	1,969	1,747
Tight Oil (bbl/d)	57,233	59,418	19,358	14,441	37,789
NGL (bbl/d) [2]	24,843	19,786	10,752	9,237	16,207
Total liquids (bbl/d)	132,853	128,972	76,762	73,082	103,151
Shale Gas (Mcf/d)	123,296	83,718	37,892	35,569	70,396
Conventional Natural Gas (Mcf/d)	41,825	46,061	40,097	46,497	43,614
Total (boe/d)	160,373	150,600	89,761	86,760	122,154

	Three Months Ended				Year Ended
	Dec. 31, 2023	Sep. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2023
CANADA					
Average Prices Received (3)					
Light and Medium Crude Oil ($/bbl)	99.72	106.32	93.82	99.22	99.87
Heavy Crude Oil ($/bbl)	62.17	84.39	66.26	51.02	66.14
Bitumen ($/bbl)	67.74	85.47	70.02	53.29	67.26
Tight Oil ($/bbl)	100.99	110.10	97.65	99.39	104.08
NGL ($/bbl) (2)	30.26	34.22	33.31	39.90	33.94
Shale Gas ($/Mcf)	2.27	2.57	2.32	3.45	2.55
Conventional Natural Gas ($/Mcf)	2.42	2.73	2.66	3.63	2.88
Total ($/boe) (8)	63.06	79.93	66.34	59.71	67.39
Royalties Paid					
Light and Medium Crude Oil and NGL ($/bbl) (2)(4)	7.98	9.49	9.46	9.25	9.08
Heavy Crude Oil ($/bbl)	12.08	14.17	11.05	8.63	11.56
Bitumen ($/bbl)	9.22	9.49	6.83	6.54	7.97
Tight Oil ($/bbl)	11.47	11.56	9.38	13.93	11.66
Shale Gas ($/Mcf)	0.08	0.02	1.66	0.34	0.30
Conventional Natural Gas ($/Mcf)	0.23	0.24	0.23	0.46	0.29
Total ($/boe) (9)	9.69	11.03	9.30	8.03	9.55
Operating Expenses (5)					
Light and Medium Crude Oil and NGL ($/bbl) (2)(4)	17.70	16.45	19.57	17.54	17.78
Heavy Crude Oil ($/bbl)	14.86	15.50	16.74	16.36	15.81
Bitumen ($/bbl)	18.27	30.78	26.32	20.52	22.87
Tight Oil ($/bbl)	8.82	10.88	17.67	12.74	11.05
Shale Gas ($/Mcf)	1.47	1.81	2.95	2.12	1.84
Conventional Natural Gas ($/Mcf)	3.07	2.87	3.01	2.68	2.89
Total ($/boe) (9)	15.61	15.98	17.97	16.70	16.51
Transportation Expenses					
Light and Medium Crude Oil and NGL ($/bbl) (2)(4)	0.56	0.49	0.53	0.92	0.63
Heavy Crude Oil ($/bbl)	4.52	4.44	4.01	4.69	4.42
Bitumen ($/bbl)	2.09	1.32	1.68	3.79	2.34
Tight Oil ($/bbl)	1.15	0.90	0.64	0.29	0.88
Shale Gas ($/Mcf)	0.19	0.15	0.11	0.05	0.15
Conventional Natural Gas ($/Mcf)	0.23	0.23	0.22	0.30	0.25
Total ($/boe) (9)	3.02	2.76	2.60	3.12	2.88
Resulting Netback (3)(6)					
Light and Medium Crude Oil and NGL ($/bbl) (2)(4)	58.55	70.36	58.19	64.62	63.22
Heavy Crude Oil ($/bbl)	30.71	50.28	34.46	21.34	34.35
Bitumen ($/bbl)	38.16	43.88	35.19	22.44	34.08
Tight Oil ($/bbl)	79.55	86.76	69.96	72.43	80.49
Shale Gas ($/Mcf)	0.53	0.59	(2.40)	0.94	0.26
Conventional Natural Gas ($/Mcf)	(1.11)	(0.61)	(0.80)	0.19	(0.55)
Total ($/boe) (8)	34.74	50.16	36.47	31.86	38.45

	Three Months Ended				Year Ended
	Dec. 31, 2023	Sep. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2023
UNITED STATES					
Average Prices Received (3)					
Tight Oil ($/bbl)	105.82	108.99	97.47	103.07	105.74
NGL ($/bbl) (2)	32.35	36.03	41.16	51.67	37.42
Shale Gas ($/Mcf)	3.07	3.20	2.52	4.02	3.15
Total ($/boe) (8)	71.34	80.64	67.60	72.22	74.27
Royalties Paid					
Tight Oil ($/bbl)	29.35	29.92	28.61	30.95	29.63
NGL ($/bbl) (2)	8.03	9.18	11.85	13.77	9.75
Shale Gas ($/Mcf)	0.72	0.76	0.62	1.07	0.76
Total ($/boe) (9)	19.42	21.89	19.66	21.02	20.51
Operating Expenses (5)(7)					
Tight Oil ($/bbl)	8.17	10.09	9.11	9.03	9.08
NGL ($/bbl) (2)	8.17	10.09	9.11	9.03	9.08
Shale Gas ($/Mcf)	1.36	1.68	1.52	1.51	1.51
Total ($/boe) (9)	8.17	10.09	9.11	9.03	9.08
Transportation Expenses					
Tight Oil ($/bbl)	0.53	0.46	0.21	—	0.44
NGL ($/bbl) (2)	3.34	4.76	0.88	—	2.88
Shale Gas ($/Mcf)	0.22	0.25	0.07	—	0.19
Total ($/boe) (9)	1.33	1.48	0.43	—	1.12
Resulting Netback (3)(6)					
Tight Oil ($/bbl)	67.77	68.52	59.54	63.09	66.59
NGL ($/bbl) (2)	12.81	12.00	19.32	28.87	15.71
Shale Gas ($/Mcf)	0.77	0.51	0.31	1.44	0.69
Total ($/boe)	42.42	47.18	38.40	42.17	43.56

Notes:

(1) Before deduction of royalties.

(2) NGL includes condensate.

(3) Before the effects of commodity derivative instruments.

(4) In Canada, NGL volumes are grouped with light crude oil volumes for reporting purposes.

(5) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, Conventional natural gas and NGL production.

(6) Netback is calculated by subtracting royalties paid, operating and transportation expenses from revenues.

(7) In the U.S., transportation expense is included in operating expenses for reporting purposes.

(8) Non-GAAP measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. See "Specified Financial Measures" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. The Baytex Annual 2023 MD&A are available on SEDAR+ at www.sedarplus.com.

(9) Supplementary financial measure. See "Royalties", "Operating Expense", and "Transportation Expense" in the Baytex Annual 2023 MD&A for information related to this measure, which section has been incorporated by reference herein. Baytex Annual 2023 MD&A are available on SEDAR+ at www.sedarplus.com.

Marketing Arrangements and Forward Contracts

We market our operated oil and natural gas production with the objective of maximizing value and counterparty performance. We have a portfolio of sales contracts with a variety of pricing mechanisms, term commitments and customers and we also have several committed transportation and processing contracts with volume and term commitments that enable us to transport our production to sales points. Production from our non-operated assets in the Eagle Ford is marketed by the operator. The Corporation also has a risk management policy pursuant to which we utilize various derivative financial instruments and physical sales contracts to manage our exposure to fluctuations in commodity prices, foreign exchange and interest rates. We also use derivative instruments in various operational markets to optimize our supply or production chain.

When marketing and hedging we engage a number of reputable counterparties to ensure competitiveness, while also managing counterparty credit exposure. For details on our contractual commitments to sell natural gas and crude oil which were outstanding at February 28, 2024, see Note 18 to our audited consolidated financial statements for the year ended December 31, 2023. See *Risk Factors.*

STATEMENT OF RESERVES DATA

The Baytex Reserves Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. The statement of reserves data and other oil and natural gas information set forth below is dated December 31, 2023. The effective date of the Baytex Reserves Report is December 31, 2023 and the preparation date of the statement is February 1, 2024. The Baytex Reserves Report was prepared using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited as of January 1, 2024.

Disclosure of Reserves Data

The following tables are a combined summary as at December 31, 2023 of our proved and probable heavy crude oil, bitumen, light and medium oil, tight oil, NGL, conventional natural gas and shale gas reserves and the net present value of the future net revenue attributable to such reserves evaluated in the Baytex Reserves Report. Our reserves are located in Canada (Alberta and Saskatchewan) and the United States (Texas).

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. 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 Baytex Reserves Report will be attained and variations could be material. The tables summarize the data contained in the Baytex Reserves Report and, as a result, may contain slightly different numbers and columns in the tables may not add due to rounding. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Readers should review the definitions and information contained in "*Selected Terms - Reserves Definitions*", "Selected Terms - *Reserves and Reserve Categories*" and "Selected Terms - *Development and Production Status*" in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors*".

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2023
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)
PROVED:						
Developed Producing	2,613	2,230	9,690	9,128	31,218	26,283
Developed Non-Producing	—	—	414	383	1,416	1,260
Undeveloped	7,226	6,310	15,699	14,882	18,445	16,292
TOTAL PROVED	9,838	8,540	25,803	24,392	51,078	43,834
PROBABLE	11,197	9,144	14,997	13,910	32,935	27,331
TOTAL PROVED PLUS PROBABLE	21,035	17,685	40,799	38,302	84,013	71,165

CANADA

RESERVES CATEGORY	BITUMEN Gross (Mbbl)	BITUMEN Net (Mbbl)	SHALE GAS Gross (MMcf)	SHALE GAS Net (MMcf)	CONVENTIONAL NATURAL GAS (1) Gross (MMcf)	CONVENTIONAL NATURAL GAS (1) Net (MMcf)
PROVED:						
Developed Producing	1,679	1,564	7,822	7,114	52,758	47,825
Developed Non-Producing	—	—	—	—	1,205	1,076
Undeveloped	2,105	1,916	20,135	18,267	23,948	20,760
TOTAL PROVED	3,783	3,480	27,957	25,381	77,910	69,661
PROBABLE	45,754	36,517	32,887	28,883	38,246	33,578
TOTAL PROVED PLUS PROBABLE	49,537	39,997	60,844	54,264	116,156	103,238

CANADA

RESERVES CATEGORY	NATURAL GAS LIQUIDS (2) Gross (Mbbl)	NATURAL GAS LIQUIDS (2) Net (Mbbl)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	3,535	3,025	58,830	51,386
Developed Non-Producing	45	35	2,076	1,856
Undeveloped	6,524	5,768	57,345	51,672
TOTAL PROVED	10,105	8,828	118,252	104,914
PROBABLE	10,452	8,849	127,189	106,161
TOTAL PROVED PLUS PROBABLE	20,557	17,677	245,441	211,075

UNITED STATES

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	SHALE GAS Gross (MMcf)	SHALE GAS Net (MMcf)	NATURAL GAS LIQUIDS [2] Gross (Mbbl)	NATURAL GAS LIQUIDS [2] Net (Mbbl)
PROVED:						
Developed Producing	67,960	51,714	137,735	104,187	34,859	26,155
Developed Non-Producing	3,703	2,789	6,761	5,087	1,769	1,327
Undeveloped	81,281	61,843	181,471	135,972	48,107	35,862
TOTAL PROVED	152,944	116,346	325,967	245,246	84,735	63,344
PROBABLE	74,041	56,404	118,877	89,396	31,882	23,839
TOTAL PROVED PLUS PROBABLE	226,985	172,749	444,844	334,642	116,617	87,183

UNITED STATES

RESERVES CATEGORY	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:		
Developed Producing	125,775	95,233
Developed Non-Producing	6,599	4,963
Undeveloped	159,632	120,368
TOTAL PROVED	292,007	220,564
PROBABLE	125,736	95,142
TOTAL PROVED PLUS PROBABLE	417,743	315,706

TOTAL

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)
PROVED:						
Developed Producing	70,573	53,944	9,690	9,128	31,218	26,283
Developed Non-Producing	3,703	2,789	414	383	1,416	1,260
Undeveloped	88,506	68,154	15,699	14,882	18,445	16,292
TOTAL PROVED	162,782	124,886	25,803	24,392	51,078	43,834
PROBABLE	85,238	65,548	14,997	13,910	32,935	27,331
TOTAL PROVED PLUS PROBABLE	248,020	190,434	40,799	38,302	84,013	71,165

TOTAL

RESERVES CATEGORY	BITUMEN		SHALE GAS		CONVENTIONAL NATURAL GAS (1)	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
PROVED:						
Developed Producing	1,679	1,564	145,556	111,300	52,758	47,825
Developed Non-Producing	—	—	6,761	5,087	1,205	1,076
Undeveloped	2,105	1,916	201,607	154,239	23,948	20,760
TOTAL PROVED	3,783	3,480	353,924	270,627	77,910	69,661
PROBABLE	45,754	36,517	151,764	118,279	38,246	33,578
TOTAL PROVED PLUS PROBABLE	49,537	39,997	505,688	388,906	116,156	103,238

TOTAL

RESERVES CATEGORY	NATURAL GAS LIQUIDS (2)		TOTAL RESERVES	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	38,394	29,180	184,606	146,619
Developed Non-Producing	1,814	1,361	8,675	6,819
Undeveloped	54,631	41,630	216,978	172,039
TOTAL PROVED	94,840	72,172	410,259	325,478
PROBABLE	42,334	32,687	252,925	201,303
TOTAL PROVED PLUS PROBABLE	137,173	104,859	663,184	526,781

Notes:

(1) Conventional natural gas includes associated, non-associated and solution gas.

(2) Natural gas liquids includes condensate.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2023
FORECAST PRICES AND COSTS

CANADA	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE TAX
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	501,765	754,762	798,250	784,960	755,505	15.53
Developed Non-Producing	57,372	47,709	40,777	35,607	31,623	21.97
Undeveloped	1,216,278	857,704	620,631	457,472	341,292	12.01
TOTAL PROVED	1,775,415	1,660,175	1,459,658	1,278,039	1,128,419	13.91
PROBABLE	3,782,900	2,189,078	1,429,040	1,011,854	758,451	13.46
TOTAL PROVED PLUS PROBABLE	5,558,315	3,849,253	2,888,697	2,289,892	1,886,871	13.69

UNITED STATES	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE TAX
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	3,941,535	3,236,204	2,708,562	2,348,256	2,090,157	28.44
Developed Non-Producing	233,766	175,727	144,837	125,113	111,115	29.18
Undeveloped	2,078,319	1,179,693	643,633	303,700	78,978	5.35
TOTAL PROVED	6,253,619	4,591,624	3,497,032	2,777,068	2,280,250	15.85
PROBABLE	3,989,677	2,256,259	1,414,413	958,969	691,108	14.87
TOTAL PROVED PLUS PROBABLE	10,243,296	6,847,882	4,911,445	3,736,037	2,971,358	15.56

TOTAL	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE TAX
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	4,443,301	3,990,966	3,506,812	3,133,215	2,845,662	23.92
Developed Non-Producing	291,137	223,436	185,614	160,720	142,738	27.22
Undeveloped	3,294,597	2,037,397	1,264,264	761,172	420,269	7.35
TOTAL PROVED	8,029,035	6,251,799	4,956,690	4,055,107	3,408,669	15.23
PROBABLE	7,772,577	4,445,337	2,843,453	1,970,823	1,449,559	14.13
TOTAL PROVED PLUS PROBABLE	15,801,611	10,697,136	7,800,142	6,025,929	4,858,228	14.81

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2023
FORECAST PRICES AND COSTS

CANADA	AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	501,765	754,762	798,250	784,960	755,505
Developed Non-Producing	57,372	47,709	40,777	35,607	31,623
Undeveloped	1,073,560	742,191	525,874	378,815	275,308
TOTAL PROVED	1,632,697	1,544,663	1,364,900	1,199,382	1,062,436
PROBABLE	2,997,861	1,685,195	1,073,160	744,551	549,089
TOTAL PROVED PLUS PROBABLE	4,630,558	3,229,857	2,438,060	1,943,933	1,611,524

UNITED STATES	AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	3,920,245	3,225,267	2,700,252	2,340,482	2,081,978
Developed Non-Producing	221,102	168,193	140,149	122,176	109,348
Undeveloped	1,672,739	941,571	495,199	208,292	17,229
TOTAL PROVED	5,814,085	4,335,031	3,335,600	2,670,950	2,208,555
PROBABLE	3,120,707	1,752,021	1,093,840	741,739	537,024
TOTAL PROVED PLUS PROBABLE	8,934,793	6,087,051	4,429,440	3,412,688	2,745,578

TOTAL	AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	4,422,010	3,980,029	3,498,502	3,125,441	2,837,483
Developed Non-Producing	278,474	215,902	180,926	157,783	140,971
Undeveloped	2,746,299	1,683,763	1,021,073	587,106	292,537
TOTAL PROVED	7,446,783	5,879,693	4,700,500	3,870,331	3,270,990
PROBABLE	6,118,568	3,437,215	2,167,000	1,486,290	1,086,112
TOTAL PROVED PLUS PROBABLE	13,565,351	9,316,908	6,867,500	5,356,621	4,357,103

Note:

(1) The after-tax net present value of future net revenue from our oil and gas properties reflects the tax burden on the properties on a theoretical stand-alone basis. It does not consider our corporate structure or any tax planning and therefore does not provide an estimate of the cumulative after-tax value of our consolidated business entities, which may be significantly different.

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

($000s)	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS[1]	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
TOTAL PROVED RESERVES								
Canada	8,003,034	957,947	2,823,801	1,539,394	906,478	1,775,415	142,718	1,632,697
United States	22,445,022	6,554,138	4,795,912	4,446,626	394,728	6,253,619	439,534	5,814,085
Total	30,448,056	7,512,084	7,619,712	5,986,020	1,301,205	8,029,034	582,252	7,446,783
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	18,207,704	2,742,694	6,045,936	2,895,776	964,984	5,558,315	927,757	4,630,558
United States	33,935,156	9,891,837	7,214,194	6,155,682	430,146	10,243,296	1,308,504	8,934,793
Total	52,142,860	12,634,531	13,260,130	9,051,458	1,395,130	15,801,611	2,236,260	13,565,351

Note:

(1) Includes well abandonment, decommissioning and reclamation costs for all producing and non-producing wells and facilities and to be incurred as a result of future development activity.

FUTURE NET REVENUE BY PRODUCT TYPE
AS OF DECEMBER 31, 2023
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1] ($/bbl; $/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and associated byproducts)	466,084	19.13
	Heavy Crude Oil (including solution gas and associated byproducts)	649,498	14.82
	Bitumen (including solution gas and associated byproducts)	48,034	13.80
	Tight Oil (including solution gas and associated byproducts)	3,111,187	25.33
	Natural Gas (associated and non-associated) (including associated byproducts)	4,268	0.14
	Shale Gas (including associated byproducts)	677,618	6.64
	Total	4,956,689	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated byproducts)	866,537	22.64
	Heavy Crude Oil (including solution gas and associated byproducts)	1,157,447	16.26
	Bitumen (including solution gas and associated byproducts)	311,673	7.79
	Tight Oil (including solution gas and associated byproducts)	4,564,916	24.29
	Natural Gas (associated and non-associated) (including associated byproducts)	22,264	0.55
	Shale Gas (including associated byproducts)	877,306	6.45
	Total	7,800,143	

Note:

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

Pricing Assumptions

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. The reference pricing used in the Baytex Reserves Report is as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2023 (1)

	Oil			Natural Gas			
Year	WTI Crude Oil (2) ($US/bbl)	Edmonton Light Crude Oil (3) ($Cdn/bbl)	Western Canadian Select (4) ($Cdn/bbl)	Henry Hub (5) ($US/MMbtu)	AECO Spot (6) ($Cdn/MMbtu)	Inflation Rate (7) (%/Yr)	Exchange Rate (8) ($US/$Cdn)
Historical							
2019	57.00	69.00	58.70	2.55	1.60	2.0	0.755
2020	39.25	45.00	35.40	2.05	2.25	0.8	0.745
2021	68.00	80.35	68.85	3.90	3.55	3.4	0.800
2022	94.80	120.75	99.10	6.40	5.55	6.8	0.770
2023	77.55	100.40	79.60	2.55	2.95	3.9	0.740
Forecast (9)							
2024	73.67	92.91	76.74	2.75	2.20	—	0.752
2025	74.98	95.04	79.77	3.64	3.37	2.0	0.752
2026	76.14	96.07	81.12	4.02	4.05	2.0	0.755
2027	77.66	97.99	82.88	4.10	4.13	2.0	0.755
2028	79.22	99.95	85.04	4.18	4.21	2.0	0.755
2029	80.80	101.94	86.74	4.27	4.30	2.0	0.755
2030	82.42	103.98	88.47	4.35	4.38	2.0	0.755
2031	84.06	106.06	90.24	4.44	4.47	2.0	0.755
2032	85.74	108.18	92.04	4.53	4.56	2.0	0.755
2033	87.46	110.35	93.89	4.62	4.65	2.0	0.755

Notes:

(1) Each price from the forecast was adjusted for quality differentials and transportation costs applicable to the specified product and evaluation area.

(2) Price used in the preparation of tight oil, condensate, and natural gas liquids reserves in the United States.

(3) Price used in the preparation of light and medium crude oil and natural gas liquids reserves in Canada.

(4) Price used in the preparation of heavy crude oil and bitumen reserves in Canada.

(5) Price used in the preparation of shale gas reserves in the United States.

(6) Price used in the preparation of Conventional natural gas reserves in Canada.

(7) Inflation rates for forecasting prices and costs.

(8) Exchange rate used to generate the benchmark reference prices in this table.

(9) After 2033 prices and costs escalate at 2.0% annually and the exchange rate remains 0.755.

Weighted average prices realized by us for the year ended December 31, 2023, excluding hedging activities, were $66.14/bbl for heavy crude oil, $67.26/bbl for bitumen, $99.87/bbl for light and medium crude oil, $104.08/bbl for tight oil, $33.94/bbl for NGL, $2.55/Mcf for shale gas and $2.88/Mcf for Conventional natural gas.

RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

CANADA	HEAVY CRUDE OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2022	51,058	34,526	85,584	4,608	45,751	50,359
Extensions	9,402	3,326	12,728	—	—	—
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	2,176	(5,336)	(3,160)	(261)	25	(236)
Discoveries	—	—	—	—	—	—
Acquisitions	7	2	9	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	741	416	1,157	75	(22)	52
Production	(12,305)	—	(12,305)	(638)	—	(638)
December 31, 2023	51,078	32,935	84,013	3,783	45,754	49,537

CANADA	LIGHT AND MEDIUM CRUDE OIL			TIGHT OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2022	41,951	21,881	63,832	7,005	6,717	13,722
Extensions	2,039	289	2,328	3,012	4,365	7,377
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [(1)]	(1,952)	(1,467)	(3,419)	488	93	580
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(11,417)	(5,772)	(17,188)	—	—	—
Economic Factors	180	65	245	21	22	43
Production	(4,999)	—	(4,999)	(687)	—	(687)
December 31, 2023	25,803	14,997	40,799	9,838	11,197	21,035

CANADA	NATURAL GAS LIQUIDS [(2)]			SHALE GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2022	7,653	6,340	13,993	19,195	18,798	37,993
Extensions	2,449	4,070	6,519	8,254	13,793	22,047
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [(1)]	791	27	817	1,847	222	2,069
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(14)	(4)	(18)	—	—	—
Economic Factors	34	19	52	63	74	136
Production	(807)	—	(807)	(1,402)	—	(1,402)
December 31, 2023	10,105	10,452	20,557	27,957	32,887	60,844

CANADA	CONVENTIONAL NATURAL GAS [3]			OIL EQUIVALENT		
	Proved (MMcf)	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2022	86,872	45,786	132,658	129,952	125,979	255,931
Extensions	1,845	899	2,744	18,585	14,498	33,083
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	4,451	(8,835)	(4,384)	2,290	(8,093)	(5,803)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	7	2	9
Dispositions	(267)	(71)	(338)	(11,475)	(5,787)	(17,262)
Economic Factors	928	467	1,395	1,215	590	1,805
Production	(15,919)	—	(15,919)	(22,322)	—	(22,322)
December 31, 2023	77,910	38,246	116,156	118,252	127,189	245,441

UNITED STATES	TIGHT OIL			NATURAL GAS LIQUIDS [2]		
	Proved (Mbbl)	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2022	41,558	14,003	55,561	62,112	22,388	84,500
Extensions	18,355	6,285	24,640	6,138	440	6,578
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(1,959)	(1,173)	(3,132)	(4,788)	(1,757)	(6,545)
Discoveries	—	—	—	—	—	—
Acquisitions	108,091	54,926	163,017	26,379	10,794	37,172
Dispositions	—	—	—	—	—	—
Economic Factors	5	1	6	3	18	21
Production	(13,106)	—	(13,106)	(5,109)	—	(5,109)
December 31, 2023	152,944	74,041	226,985	84,735	31,882	116,617

UNITED STATES	SHALE GAS			OIL EQUIVALENT		
	Proved (MMcf)	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2022	183,773	65,834	249,607	134,299	47,363	181,662
Extensions	32,594	4,686	37,280	29,926	7,506	37,431
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(9,629)	(5,495)	(15,125)	(8,352)	(3,846)	(12,198)
Discoveries	—	—	—	—	—	—
Acquisitions	143,499	53,785	197,284	158,386	74,683	233,069
Dispositions	—	—	—	—	—	—
Economic Factors	23	68	91	12	30	42
Production	(24,293)	—	(24,293)	(22,264)	—	(22,264)
December 31, 2023	325,967	118,877	444,844	292,007	125,736	417,743

TOTAL	HEAVY CRUDE OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2022	51,058	34,526	85,584	4,608	45,751	50,359
Extensions	9,402	3,326	12,728	—	—	—
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	2,176	(5,336)	(3,160)	(261)	25	(236)
Discoveries	—	—	—	—	—	—
Acquisitions	7	2	9	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	741	416	1,157	75	(22)	52
Production	(12,305)	—	(12,305)	(638)	—	(638)
December 31, 2023	51,078	32,935	84,013	3,783	45,754	49,537

TOTAL	LIGHT AND MEDIUM CRUDE OIL			TIGHT OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2022	41,951	21,881	63,832	48,563	20,719	69,283
Extensions	2,039	289	2,328	21,367	10,650	32,017
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [(1)]	(1,952)	(1,467)	(3,419)	(1,472)	(1,080)	(2,552)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	108,091	54,926	163,017
Dispositions	(11,417)	(5,772)	(17,188)	—	—	—
Economic Factors	180	65	245	25	23	49
Production	(4,999)	—	(4,999)	(13,793)	—	(13,793)
December 31, 2023	25,803	14,997	40,799	162,782	85,238	248,020

TOTAL	NATURAL GAS LIQUIDS [(2)]			SHALE GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2022	69,765	28,728	98,493	202,967	84,633	287,600
Extensions	8,587	4,510	13,096	40,849	18,478	59,327
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [(1)]	(3,997)	(1,730)	(5,727)	(7,782)	(5,274)	(13,056)
Discoveries	—	—	—	—	—	—
Acquisitions	26,379	10,794	37,172	143,499	53,785	197,284
Dispositions	(14)	(4)	(18)	—	—	—
Economic Factors	36	36	73	86	142	228
Production	(5,916)	—	(5,916)	(25,695)	—	(25,695)
December 31, 2023	94,840	42,334	137,173	353,924	151,764	505,688

TOTAL	**CONVENTIONAL NATURAL GAS** [3]			**OIL EQUIVALENT**		
	Proved (MMcf)	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2022	86,872	45,786	132,658	264,251	173,342	437,593
Extensions	1,845	899	2,744	48,510	22,004	70,514
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	4,451	(8,835)	(4,384)	(6,062)	(11,939)	(18,001)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	158,394	74,685	233,079
Dispositions	(267)	(71)	(338)	(11,475)	(5,787)	(17,262)
Economic Factors	928	467	1,395	1,226	620	1,846
Production	(15,919)	—	(15,919)	(44,586)	—	(44,586)
December 31, 2023	77,910	38,246	116,156	410,259	252,925	663,184

Notes:

(1) Negative technical revisions in light and medium oil are predominantly associated with higher field operating costs in our Viking asset truncating end of life forecasts and actual performance not meeting forecast. Negative technical revisions in tight oil, shale gas and natural gas liquids in our legacy non-operated Eagle Ford assets are predominantly associated with actual performance not meeting forecast and the removal of locations due to inventory consolidation and spacing changes. Negative probable technical revisions in heavy oil are predominantly associated with performance re-characterization of undeveloped locations in the Peace River area. Positive proved technical revisions in heavy oil are predominantly associated with improved performance of producing wells in Peace River, Lloydminster and Peavine areas.

(2) Natural gas liquids includes condensate.

(3) Conventional natural gas includes associated, non-associated and solution gas.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed 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.

We allocate development capital to our assets annually. We reduce risk by technically assessing the prior year's results from our development programs before committing additional capital. Furthermore, planned activity levels vary each year due to factors such as prevailing commodity prices, capital availability, operational spacing considerations, timing of infrastructure construction and regulatory processes. This approach means that in most cases it will take longer than three years to develop our proved undeveloped reserves and longer than five years to develop our proved plus probable undeveloped reserves. With the exception of our Gemini SAGD project, we plan to develop the majority of our proved undeveloped reserves over the next five years and our probable undeveloped reserves over the next seven years.

At our Gemini SAGD project, steam generation represents a large proportion of the capital and operating costs. Therefore, our development plans anticipate that, in order to make the most efficient use of our steam generating and oil treating facilities, the drilling and steaming of wells (once commenced) would take place over approximately 26 years. We have booked 44.5 MMbbls of probable undeveloped reserves to the Gemini SAGD project.

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed during, and the volume booked at year-end for, the three most recently completed financial years.

	Light and Medium Crude Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Crude Oil Gross (Mbbl)		Bitumen Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2021	2,062	26,781	3,767	26,278	8,208	21,503	—	4,197
2022	1,322	24,814	671	20,757	3,744	20,247	—	3,668
2023	407	15,699	71,679	88,506	4,328	18,445	—	2,105

	Conventional Natural Gas Gross (MMcf)		Shale Gas Gross (MMcf)		Natural Gas Liquids Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2021	12,540	37,216	14,415	129,213	4,186	39,431
2022	9,633	25,831	1,503	117,354	842	39,235
2023	769	23,948	93,446	201,607	18,527	54,631

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were attributed during, and the volume booked at year-end for, the three most recently completed financial years.

	Light and Medium Crude Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Crude Oil Gross (Mbbl)		Bitumen Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2021	2,464	16,940	(2,379)	15,839	(330)	21,391	—	45,567
2022	503	16,162	972	14,667	4,425	23,162	—	45,489
2023	247	11,560	55,029	68,578	4,450	21,271	—	45,110

	Conventional Natural Gas Gross (MMcf)		Shale Gas Gross (MMcf)		Natural Gas Liquids Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2021	(7,079)	38,947	(10,331)	64,259	(2,904)	20,836
2022	4,535	24,180	2,288	66,653	842	22,175
2023	828	19,672	55,986	118,276	12,638	33,386

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

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

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

In the event that prices for oil and gas are not consistent with those used to prepare the Baytex Reserves Report, the volume of our reserves, their net present value and our expected revenues will differ, perhaps materially so, from those stated in the Baytex Reserves Report.

In connection with our operations, we will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of our surface leases, wells and facilities. The total liability associated with these existing surface leases, wells and facilities, inflated at 2% per year, is estimated to be $1,179 million undiscounted ($269 million discounted at 10 percent). This is comprised of $595 million undiscounted ($66 million discounted at 10 percent) associated with active properties, $313 million undiscounted ($173 million discounted at 10 percent) associated with inactive properties, and $271 million undiscounted ($30 million discounted at 10 percent) associated with facilities.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below (using forecast prices and costs).

FUTURE DEVELOPMENT COSTS
AS OF DECEMBER 31, 2023
FORECAST PRICES AND COSTS
($000s)

	CANADA		**UNITED STATES**		**TOTAL**	
	Proved Reserves	**Proved plus Probable Reserves**	**Proved Reserves**	**Proved plus Probable Reserves**	**Proved Reserves**	**Proved plus Probable Reserves**
2024	272,920	304,942	764,683	764,683	1,037,603	1,069,625
2025	344,836	401,744	911,155	911,155	1,255,992	1,312,899
2026	407,655	516,090	926,320	926,320	1,333,975	1,442,410
2027	220,633	573,732	1,005,901	1,005,901	1,226,534	1,579,633
2028	221,484	415,670	838,566	1,035,629	1,060,050	1,451,299
Remaining	71,867	683,597	—	1,511,994	71,867	2,195,592
Total (undiscounted)	1,539,394	2,895,776	4,446,626	6,155,682	5,986,020	9,051,458

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity financing. Planned activity levels vary each year due to factors such as capital availability, prevailing commodity prices and regulatory processes.

There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Baytex Reserves Report. Failure to develop those reserves could have a negative impact on our future cash flow.

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

RISK FACTORS

You should carefully consider the following risk factors, as well as the other information contained in this AIF and our other public filings before making an investment decision. If any of the risks described below materialize, our business, reputation, financial condition, results of operations and cash flow could be materially and adversely affected, which may materially affect the market price of our securities. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect us. Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading "*Certain Risks for United States and other non-resident Shareholders".*

The information set forth below contains forward-looking statements, which are qualified by the information contained in the section of this AIF entitled "*Special Notes to Reader - Forward-Looking Statements*".

Risks Relating to Our Business and Operations

Crude oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Corporation's business, results of operations, or cash flows and financial condition

Our financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Low prices for crude oil and natural gas produced by us could have a material adverse effect on our operations, financial condition and the value and amount of our reserves.

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, OPEC+, the condition of the Canadian, United States, European and Asian economies, the impacts of geopolitical events, including the Russian Ukrainian war and conflicts in the Middle East, or other adverse economic or political development in the United States, Europe, or Asia, the impact of pandemics/epidemics, government regulation, the supply of crude oil in North America and internationally, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Additionally, the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium crude oil and heavy crude oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, storage capacity, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. In addition, there is not sufficient pipeline capacity for Canadian crude oil to access the American refinery complex or tidewater to access world markets and the availability of additional transport capacity via rail is more expensive and variable, therefore, the price for Canadian crude oil is very sensitive to pipeline and refinery outages, which contributes to this volatility.

There is a also a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the U.S. If light sweet crude oil production remains at current levels or continues to increase, demand for the light crude oil production from our U.S. operations could result in widening price discounts to the world crude prices.

Decreases to or prolonged periods of low commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due. It could also result in the shut-in of currently producing wells without an equivalent decrease in expenses due to fixed costs, a delay or cancellation of existing or future drilling, development or construction programs, un-utilized long-term transportation commitments and a reduction in the value and amount of our reserves.

We conduct assessments of the carrying value of our assets in accordance with Canadian GAAP. If crude oil and natural gas forecast prices change, the carrying value of our assets could be subject to revision and our net earnings could be adversely affected.

Our success is highly dependent on our ability to develop existing properties and add to our oil and natural gas reserves

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced. As a result, our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient hydrocarbons to return a profit. Completion of a well does not assure a profit on the investment. Drilling hazards or environmental liabilities or damages and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays or failure in obtaining governmental, landowner or other stakeholder approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow from operating activities to varying degrees.

There is no assurance we will be successful in developing our reserves or acquiring additional reserves at acceptable costs. Without these reserves additions, our reserves will deplete and as a consequence production from and the average reserve life of our properties will decline, which may adversely affect our business, financial condition, results of operations and prospects.

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

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production. Competition for these assets has been and will continue to be intense. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition or do so on commercially acceptable terms. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Additionally, significant acquisitions can change the nature of our operations and business if acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Management continually assesses the value and contribution of its Corporation's assets. In this regard, non-core assets may be periodically disposed of so that the Corporation can focus its 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 the financial statements of the Corporation.

Availability and cost of capital or borrowing to maintain and/or fund future development and acquisitions

The business of exploring for, developing or acquiring reserves is capital intensive. If external sources of capital (including, but not limited to, debt and equity financing) become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired.

Our ability to obtain additional capital is dependent on, among other things, a general interest in energy industry investments and, in particular, interest in our securities along with our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded. Additionally, from time to time, our securities may not meet the investment criteria or characteristics of a particular institutional or other investor, including institutional investors who are not willing or able to hold securities of oil and gas companies for reasons unrelated to financial or operational performance. This may include changes to market-based factors or investor strategies, including ESG, or responsible investing criteria/rankings (for example, ESG, social impact or environmental scores), the implementation of new financial market regulations and fossil fuel divestment initiatives undertaken by governments, pension funds and/or other institutional investors. These events would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing, and may increase our borrowing costs.

From time to time we may enter into transactions which may be financed in whole or in part with debt or equity. 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. Additionally, from time to time, we may issue securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

Restrictions and/or costs associated with regulatory initiatives to combat climate change and the physical risks of climate change may have a material adverse affect on our business

Regulatory and Policy Initiatives

Our exploration and production facilities and other operational activities emit GHGs. As such, GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us. In addition, certain of our assets have a higher GHG emissions intensity than others and may be disproportionately impacted.

Negative consequences which could result from new GHG emissions regulation include, but are not limited to: increased operating costs, additional taxes, increased construction and development costs, additional monitoring and compliance costs, a requirement to redesign or retrofit current facilities, permitting delays, additional costs associated with the purchase of emission credits or allowances and reduced demand for crude oil. Additionally, if GHG emissions regulation differs by region or type of production, all or part of our production could be subject to costs which are disproportionately higher than those of other producers.

The direct or indirect costs of compliance with GHG emissions regulation may have a material adverse affect on our business, financial condition, results of operations and prospects. At this time, it is not possible to predict whether compliance costs will have a material adverse affect on our financial condition, results of operations or prospects.

Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated obligations, there can be no assurance that we will be able to satisfy our actual future obligations associated with GHG emissions from such funds. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions - Climate Change Regulation*".

Physical Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rain fall, hurricanes, drought and wildfires may restrict our ability to access our properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain assets are located where they are exposed to forest fires, floods, heavy rains, hurricanes, drought and other extreme weather conditions which can lead to significant downtime, damage to such assets and/or increased costs of construction and maintenance. Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

An energy transition that lessens demand for petroleum products may have an adverse affect on our business

A transition away from the use of petroleum products, which may include conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy, could reduce demand for oil and natural gas. Certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business and financial condition by decreasing its cash flow from operating activities and the value of its assets.

The amount of oil and natural gas that we can produce and sell is subject to the availability and cost of gathering, processing and pipeline systems

We deliver our products through gathering, processing and pipeline systems to which we do not own and purchasers of our products rely on third party infrastructure to deliver our products to market. The lack of access to capacity in any of the gathering, processing and pipeline systems could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Alternately, a substantial decrease in the use of such systems can increase the cost we incur to use them. In addition, many of the pipeline systems that we use are controlled by a single company and rates are set through a regulatory process, as a result we are subject to the outcome of those regulatory processes. Any significant change in market factors, regulatory decisions or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition.

Our operations in the United States are concentrated in the Eagle Ford shale of South Texas and as a result are highly exposed to the gulf coast refining complex and events which negatively impact the functioning of infrastructure in that area, including as a result of weather conditions, terrorism, local market changes, government regulation and taxation, including limits on the U.S.' ability to export crude oil, could harm our business and, in turn, our financial condition.

Access to the pipeline capacity for the export of crude oil from Canada has, at times, been inadequate for the amount of Canadian production being exported. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that current investment in pipelines will provide sufficient long-term take-away capacity or that currently operating systems will remain in service. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail transportation and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on pipeline systems. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather, derailment or blockades and could adversely impact our crude oil sales volumes or the price received for our product. Crude oil produced and sold by us may be involved in a derailment or incident that results in legal liability or reputational harm.

A portion of our production may be processed through facilities controlled by third parties. 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 discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Failure to retain or replace our leadership and key personnel may have an adverse affect on our business

Our success is dependent upon our management, our leadership capabilities and the quality and competency of our talent. Contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of central importance. In addition, certain of the Corporation's current employees may have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and prospects.

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

Income tax laws and government incentive programs relating to the oil and gas industry may change in a manner that adversely affects our financial condition, results of operations and prospects.

In addition, tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our Shareholders. We file all required income tax returns and believe that we are in full compliance with the applicable tax legislation. However, such returns are subject to audit and reassessment by the applicable taxation authority. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries. For further details, see *"Legal Proceedings and Regulatory Actions"*. Any such reassessment may have an impact on current and future taxes payable. We believe appropriate provisions for current and deferred income taxes have been made in our Financial Statements; however, it is difficult to predict the outcome of audit findings by tax authorities. These findings may increase the amount of our tax liabilities and adversely affect our business, financial condition and results of operations.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

We have a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. Our ability to complete projects is dependent on general business, community relationships and market conditions as well as other factors beyond our control, including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity and rail terminals, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment and supplies, and availability of processing capacity.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the frequency of operational shut-ins and unintentional communication with other adjacent wells and reduce the total recoverable reserves from the reservoir.

Our financial performance is significantly affected by the cost of developing and operating our assets

Our development and operating costs are affected by a number of factors including, but not limited to: price inflation, access to skilled and unskilled labour, availability of equipment, scheduling delays, trucking and fuel costs, failure to maintain quality construction standards, the cost of new technologies and supply chain disruptions. Labour costs, natural gas, electricity, water, diluent and chemicals are examples of some of the operating and other costs that are susceptible to significant fluctuation. Increases to development and operating costs could have a material adverse effect on our financial condition, results of operations or prospects.

Current or future controls, legislation or regulations applicable to the oil and gas industry could adversely affect us

Operations

The oil and gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government. All such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse. The exercise of discretion by governmental authorities under existing controls, legislation or regulations, the implementation of new controls, legislation or regulations or the modification of existing controls, legislation or regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse effect on our financial condition, results of operations or prospects. See "*Industry Conditions*".

Environment

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, state, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, and restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal, state, 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*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and 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 the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

The Corporation may have to pay certain costs associated with abandonment and reclamation

The Corporation will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its 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 the Corporation's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial. The Corporation records a provision for abandonment and reclamation costs in it's financial statements, this provision requires significant judgement and reflects the Corporation's best estimate of the costs to complete the required abandonment and reclamation work. Actual results may be significantly different than the estimated amounts.

Foreign Investment and Competition Act Legislation

In addition to regulatory requirements mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) and the *Hart-Scott-Rodino Antitrust Improvements Act* in the United States.

Water use restrictions and/or limited access to water or other fluids may impact the Corporation's ability to fracture its wells or carry out waterflood operations

The Corporation undertakes or intends to undertake certain hydraulic fracturing, SAGD, CSS and waterflooding programs. To undertake such operations the Corporation needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Corporation 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 hydraulic fracturing, SAGD, CSS and waterflooding. If the Corporation is unable to access such water it may not be able to undertake hydraulic fracturing, SAGD, CSS or waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Public perception and its influence on the regulatory regime

Concern over the impact of oil and gas development on the environment and climate change has received considerable attention in the media and recent public commentary, and the social value proposition of resource development is being challenged. Additionally, certain pipeline leaks, rail car derailments, major weather events and induced seismicity events have gained media, environmental and other stakeholder attention. Future laws and regulation may be impacted by such incidents, which could have a material adverse effect on our financial condition, results of operations or prospects.

New regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes

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

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

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

Our hedging activities may negatively impact our income and our financial condition

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a hedging program. The terms of these arrangements may limit the benefit to us of favourable changes in these factors, including receiving less than the market price for our production, and for certain assets will result in us paying royalties at a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk. To the extent that our current hedging agreements are beneficial to us, these benefits will only be realized for the period and for the commodity quantities in those contracts. In addition, there is no certainty that we will be able to obtain additional hedges at prices that have an equivalent benefit to us, which may adversely impact our revenues in future periods. For more information about our commodity hedging program, see *"General Description of our Business - Marketing Arrangements and Forward Contracts"*.

Variations in interest rates and foreign exchange rates could adversely affect our financial condition

There is a risk that interest rates will continue to increase. An increase in interest rates could result in a significant increase in the amount we pay to service debt and could have an adverse effect on our financial condition, results of operations and prospects.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canada/U.S. foreign exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our revenues. A substantial portion of our operations and production are in the United States and, as such, we are exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. In addition, we are exposed to foreign currency risk as a large portion of our indebtedness is denominated in U.S. dollars and the interest payable thereon is payable in U.S. dollars. Future Canada/U.S. foreign exchange rates could also impact the future value of our reserves as determined by our independent evaluator.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves, including many factors beyond our control

The reserves estimates included in this AIF are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenues therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies, historical production from the properties, initial production rates, production decline rates, the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and estimates of future commodity prices and capital costs, all of which may vary considerably from actual results.

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our reserves as at December 31, 2023 are estimated using forecast prices and costs as set forth under "Statement of Reserves Data - Pricing *Assumptions*". If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the estimated price assumptions, the present value of estimated future net revenues for our reserves and net asset value would be reduced and the reduction could be significant. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.

Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves and such variances could be material.

Acquiring, developing and exploring for oil and natural gas involves many physical hazards. We have not insured and cannot fully insure against all risks related to our operations

Our crude oil and natural gas operations are subject to all of the risks normally incidental to the: (i) storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) operation and development of crude oil and natural gas properties, including, but not limited to: encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, fires, explosions, equipment failures and other accidents, gaseous leaks, uncontrollable or unauthorized flows of crude oil, natural gas or well fluids, migration of harmful substances, oil spills, corrosion, adverse weather conditions, pollution, acts of vandalism, theft and terrorism and other adverse risks to the environment.

Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and 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. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect on our business, financial condition, results of operations and prospects.

We are not the operator of a significant portion of our drilling locations in the Eagle Ford and, therefore, we will not be able to control the timing of development, associated costs or the rate of production of that acreage

Marathon Oil is the operator of a significant portion of our Eagle Ford acreage which is located in the Karnes and Atascosa counties and we are reliant upon Marathon Oil to operate successfully. Marathon Oil will make decisions based on its own best interest and the collective best interest of all of the working interest owners of this acreage, which may not be in our best interest. We have a limited ability to exercise influence over the operational decisions of Marathon Oil, including the setting of capital expenditure budgets and determination of drilling locations and schedules. The success and timing of development activities, operated by Marathon Oil, will depend on a number of factors that will largely be outside of our control, including the timing and amount of capital expenditures, Marathon Oil's expertise and financial resources, approval of other participants in drilling wells, selection of technology, and the rate of production of reserves.

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets. We have the ability to elect whether or not to participate in well locations proposed by Marathon Oil on an individual basis. If we elect to not participate in a well location, we forgo any revenue from such well until Marathon Oil has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such well.

Our thermal heavy oil projects face additional risks compared to conventional oil and gas production

Our thermal heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil, such as CSS and SAGD, are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using new technologies. A large increase in recovery costs could cause certain projects that rely on CSS, SAGD or other new technologies to become uneconomic, which could have an adverse effect on our financial condition and our reserves. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

Project economics and our earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation: the costs imposed by GHG emissions regulations, labour costs, the cost of catalysts and chemicals, the cost of natural gas and electricity, water handling and availability, power outages, produced sand causing issues of erosion, hot spots and corrosion, reliability of facilities, maintenance costs, the cost to transport sales products and the cost to dispose of certain by-products.

We may be unable to compete successfully with other organizations in the oil and natural gas industry, or obtain required vendor services to compete

The oil and natural gas industry is highly competitive in all of its phases. The Corporation competes with numerous other entities in the exploration for, and the development, production and marketing of, oil and natural gas, as well as for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled/ qualified labour, access to drilling rigs, service rigs and other equipment and materials such as drilling rigs, hydraulic fracturing pumping equipment and related skilled personnel, access to processing facilities, pipeline and refining capacity, as well as many other services, and in many other respects, with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. As a result, some of the Corporation's competitors may have greater opportunities and be able to access, services or vendors that the Corporation is not able to access, thereby limiting its ability to compete.

Our information technology systems are subject to certain risks

We utilize and have become increasingly dependent upon a number of information technology systems for the administration and management of our business and 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 the Corporation's information technology systems by third parties or insiders. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although the Corporation has security measures and controls in place to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws, and/or disruption to business activities. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Adverse results from litigation may have an adverse affect on our business and reputation

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, and environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on our financial condition. For further details, see "*Legal Proceedings and Regulatory Actions*".

Our Credit Facilities may not provide sufficient liquidity and a failure to renew our Credit Facilities at maturity could adversely affect our financial condition

Our Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms, if at all. There can be no assurance that the amount of our Credit Facilities will be adequate for our future financial obligations, including future capital expenditures, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund ongoing operations. In the event that the Credit Facilities are not extended prior to maturity, indebtedness under the Credit Facilities will be repayable at that time. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms. See "*Description of Capital Structure*".

Failure to comply with the covenants in the agreements governing our debt, including our obligation to repay the Senior Notes at maturity, could adversely affect our financial condition

We are required to comply with the covenants in our Credit Facilities and the Senior Notes. If we fail to comply with such covenants, are unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of our assets by our creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards our debt would the remainder, if any, be available for the benefit of our Shareholders.

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 Provinces of Alberta and Saskatchewan and the State of Texas. 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.

Indigenous Land and Rights Claims

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

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

We are subject to risk of default by the counterparties to our contracts and our counterparties may deem us to be a default risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flow from operating activities and financial position. Conversely, our counterparties may deem us to be at risk of defaulting on our contractual obligations. These counterparties may require that we provide additional credit assurances by prepaying anticipated expenses or posting letters of credit, which would decrease our available liquidity and increase our costs.

Geopolitical risk and conflicts in or around major oil and gas producing nations can significantly impact commodity prices and, therefore the financial condition of the oil and gas industry

Existing or future conflicts in major oil and gas producing nations and the international response may have potential wide-ranging consequences for global market volatility and economic conditions, including affecting crude oil and natural gas prices. Financial and trade sanctions that may be imposed against countries involved in such conflicts may have continued far-reaching effects on the global economy, energy and commodity prices. The short-, medium- and long-term implications of any such conflicts is difficult to predict with any degree of certainty. Depending on the extent, duration, and severity of such conflict(s), it may have the effect of heightening many of the other risks described herein, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; crude oil and natural gas prices; inflationary pressures, interest rates and costs of capital; and supply chains and cost-effective and timely transportation.

The Corporation could lose its status as a "foreign private issuer" in the United States

The Corporation is required to assess its "foreign private issuer" ("FPI") status under U.S. securities laws on an annual basis at the end of its second quarter. While the Corporation currently qualifies as an FPI, it could lose its FPI status in the future. If the Corporation were to lose its status as an FPI it would be required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country. In addition, if the Corporation loses its FPI status, it would be required to report as a U.S. domestic issuer and be subject to other U.S. securities laws applicable to U.S. domestic issuers. The regulatory and compliance costs to the Corporation under U.S. securities laws as a U.S. domestic issuer may be significantly greater than the costs the Corporation incurs as a foreign private issuer. For example, as a U.S. domestic issuer, the Corporation would be required to file periodic reports and registration statements with the SEC on U.S. domestic issuer forms, which are more detailed and extensive in certain respects than the forms available to the Corporation as a foreign private issuer. The Corporation would also be required to report its oil and gas reserves and production information in accordance with applicable U.S. disclosure requirements. Such conversion and modifications would involve additional costs and may restrict the Corporation's access to capital markets for a period of time until it has satisfied SEC reporting requirements. In addition, the Corporation may lose its ability to rely upon exemptions from certain corporate governance requirements on U.S. stock exchanges that are available to FPIs, which could also increase its costs.

Conflicts of interest may arise between the Corporation and its directors and officers

Circumstances may arise where directors and officers of the Corporation are directors or officers of other companies involved in the oil and gas industry which are in competition to, or otherwise in conflict with, the interests of the Corporation. Directors are required to abstain from voting on matters when they are in conflict. Employees, including officers, are not permitted to partake in activities that do not support the best interests of the Corporation. Where employee conflicts exist, they are to be provided in writing to our Human Resources Department, which discloses all conflicts to Chief Legal Officer. See "*Directors and Officers – Conflicts of Interest*" and the Corporation's Code of Business Conduct and Ethics at www.baytexenergy.com.

Risks Related to Ownership of our Securities

Changes in market-based factors may adversely affect the trading price of the Common Shares

The market price of our Common Shares is sensitive to a variety of market-based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates, the decision of certain indices to include our Common Shares and the comparability of the Common Shares to other securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Forward-Looking Information rely upon assumptions which may not prove correct

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

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

Dividends on the Corporation's Common Shares and Common Share repurchases are variable

The future acquisition by the Corporation of Common Shares pursuant to a share buyback (including through its NCIB) and the payment of dividends, if any, and the level thereof is uncertain. Any decision to acquire Common Shares pursuant to a share buyback or to pay dividends will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Corporation's business performance, financial condition, financial requirements, commodity prices, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Corporation under applicable corporate law. In the future, there can be no assurance of the number of Common Shares that the Corporation will acquire pursuant to a share buyback and there can be no assurance that dividends will be paid or, if paid the amount of such dividends.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

We are a corporation incorporated under the laws of the Province of Alberta, Canada, our principal office is located in Calgary, Alberta and a substantial portion of our assets are located outside the United States. Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent qualified reserves evaluators), and all or a substantial portion of their assets are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

We report our production and reserves quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, whereas the SEC rules require that a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, be utilized.

We have included in this AIF estimates of proved reserves and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed in this AIF may not be comparable to United States standards.

As a consequence of the foregoing, our reserves estimates and production volumes in this AIF may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents

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

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive controls and regulation in respect of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government. The oil and gas industry is also subject to agreements among the governments of Canada, Alberta, Saskatchewan, the United States and Texas with respect to pricing and taxation of oil and natural gas. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada and the United States.

Pricing and Marketing

Oil

In Canada and the United States, producers of oil are entitled to negotiate sales contracts directly with oil purchasers. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional markets and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale.

Oil can be exported from Canada provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**") and the term of the export contract does not exceed one year in the case of light crude oil and two years in the case of heavy crude oil. Any Canadian oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB. Oil exports from the United States are controlled by the United States Department of Commerce. However, since December, 2015, only exports to embargoed or sanctioned countries require authorization from the U.S. Department of Commerce.

In an effort to increase the price for crude oil and bitumen produced in Alberta, the Government of Alberta announced production curtailments which came into effect on January 1, 2019. As implemented, each producer was provided a production allocation determined in part based upon each producer's prior year production measured over a one month or six month period. Production curtailments were removed as of December 2020 and the Government of Alberta stated that it will monitor market conditions and may reintroduce the curtailments if storage levels approach capacity.

Natural Gas

In Canada and the United States, producers of natural gas are entitled to negotiate sales contracts directly with purchasers. Supply and demand determine the price of natural gas, which is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short-term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an export license from the NEB.

Natural gas exported from the United States is regulated principally by the Federal Energy Regulatory Commission ("**FERC**") and the United States Department of Energy ("**DOE**"). U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a free trade agreement with the United States that provides for national treatment of trade in natural gas; however, the DOE regulation of imports and exports from and to countries without such free trade agreements is more comprehensive.

The FERC regulates rates and service conditions for the transportation of natural gas in interstate commerce. The prices and terms of access to intrastate pipeline transportation are subject to state regulation. In Texas, the primary regulator is the Railroad Commission of Texas ("**RRC**"). Facilities used in the production or gathering of natural gas in interstate commerce are generally exempt from FERC jurisdiction. However, the distinction between FERC-regulated transmission pipelines and unregulated gathering systems is made by the FERC on a case-by-case basis and has been subject to extensive litigation.

North American Free Trade

The North American Free Trade Agreement among the governments of Canada, the United States and Mexico came into force on January 1, 1994. On July 1, 2020 this agreement was updated and replaced by the United States Mexico Canada Agreement "**USMCA**". In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36-month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement, except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. USMCA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

In addition to federal regulation, each province in Canada and each state in the United States has legislation and regulations that govern royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of hydrocarbon production. Royalties payable on production from lands other than Crown lands in Canada and federal and state lands in the United States are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain taxes and royalties. Royalties from production on Crown lands in Canada and federal and state lands in the United States are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced.

From time to time the federal and provincial governments in Canada and the federal and state governments in the United States create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced to encourage specific types of exploration and development activity.

Land Tenure

In the Provinces of Alberta and Saskatchewan, the rights to crude oil and natural gas are predominantly owned by the provincial government. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses, and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. In the United States, private ownership of the rights to crude oil and natural gas is predominant. Where mineral rights are privately owned, the rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated. Private ownership of oil and natural gas also exists in western Canada. Government and private leases are generally granted for an initial fixed term but may generally be continued provided certain minimum levels of drilling operations or production have been achieved and all lease rentals have been timely paid, subject to certain exceptions.

To develop minerals, including oil and gas, it is necessary for the mineral estate owner(s) to have access to the surface estate. Under common law in Canada and the United States, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each province and state has developed and adopted their own statutes that operators must follow both prior to drilling and following drilling, including notification requirements and the provision of compensation for lost land use and surface damages. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

Liability Management Rating Programs

The provinces of Alberta and Saskatchewan both have liability management programs in respect of conventional upstream oil and gas wells, facilities and pipelines. Both programs require a licensee whose deemed liabilities equal or exceed its deemed assets within the jurisdiction to provide a security deposit. In response to energy company insolvencies and the associated financial risk, Alberta and Saskatchewan have expanded their liability management programs to become more stringent in recent years. Additional measures of corporate health, beyond simple asset and liability ratios, are now utilized to determine whether a company can hold, transfer or acquire well licenses. These holistic assessments of companies have reduced the number of parties which can acquire assets. Alberta and Saskatchewan have also introduced mandatory asset retirement obligation spending programs. These programs require a licensee to spend a set percentage of its deemed liability, each year, on abandonment, decommissioning and reclamation.

In Texas, each operator of a well must file a bond, letter of credit, or cash deposit with the RRC. The amount of the bond, letter of credit or deposit varies by number and type of wells, but is not dependent upon the financial capacity of the operator.

Environmental Regulation

The oil and natural gas industry is currently subject to stringent environmental regulation pursuant to a variety of municipal, provincial, state and federal controls, laws, rules and regulations governing the spill, release or emission of materials into the environment, or otherwise relating to environmental protection, all of which is subject to governmental review and revision from time to time. Such controls, laws, rules and regulations, among other things, require the acquisition of permits or other approvals to conduct drilling and other regulated activities; restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; impose specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from drilling and production operations. In addition, controls, laws, rules and regulations set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such controls, laws and regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, remedial obligations, civil liability and the imposition of material administrative, civil and criminal penalties.

Environmental legislation in the Province of Alberta is, for the most part, set out in the Environmental Protection and Enhancement Act and the Oil and Gas Conservation Act, which impose strict environmental standards with respect to releases of effluents and emissions, including monitoring and reporting obligations, and impose significant penalties for non-compliance. Environmental legislation in the Province of Saskatchewan is, for the most part, set out in the Environmental Management and Protection Act, 2002 and the Oil and Gas Conservation Act, which regulate harmful or potentially harmful activities and substances, any release of such substances, and remediation obligations.

In the United States, environmental regulation is administered by numerous agencies under multiple statutes, as amended from time to time. The environmental and occupational health and safety agencies that most significantly affect our operations include the Federal Environmental Protection Agency ("**EPA**"), the Texas Commission on Environmental Quality ("**TCEQ**") and the RRC.

The EPA regulates activities that could affect human health and the environment. It derives its authority from a long list of Acts of Congress, including the Clean Water Act, the Clean Air Act, the Oil Pollution Act, the Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act and the Safe Drinking Water Act. The EPA establishes and strictly enforces standards for environmental pollution. At the state level in Texas, the TCEQ regulates public health and natural resources, including air, water and waste, and the RRC regulates the stewardship of oil and natural gas resources, along with some aspects of environmental protection and safety related to extraction of those resources. The RRC regulations establish environmental remediation and reporting criteria for the cleanup of oil and produced water spills.

Climate Change Regulation and Litigation

Canada and the United States are signatories to the United Nations Framework Convention on Climate Change (the "UNFCCC") and are participants in the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing GHG emissions). Both governments also signed the Paris Agreement in December 2015, which included a commitment to keep any increase in global temperatures below two degrees Celsius, and a commitment pursue efforts to limit any increase to 1.5 degrees. To deliver on these long-term commitments, nations establish reduction targets through Nationally Determined Contributions. Under the Trump administration the United States withdrew from the Paris Agreement in 2017 and subsequently rejoined under the Biden administration in 2021. In 2021, Canada and the United States joined over 90 other countries in the Global Methane Pledge which aims to reduce global methane emissions 30% below 2020 levels by 2030. With the release of a joint statement in 2023, both countries reaffirmed their respective commitments and bilateral collaboration in developing and implementing their respective oil and gas methane regulations.

Canada’s climate plan includes a target to cut GHG emissions by 40-45% from 2005 levels by 2030 and a commitment to reaching net zero emissions by 2050 has been legislated. A number of policy measures have been put in place to assist in achieving these targets. In 2022, Canada released its first Emissions Reduction Plan under the Canadian Net-Zero Emissions Accountability Act. It models a pathway to achieving Canada’s 2030 target and includes a 42% decrease in oil and gas sectorial emissions from current levels. In 2023, Canada released draft methane regulations for at least a 75 percent reduction in oil and gas methane below 2012 levels by 2030. The Government of Canada has identified capping and cutting oil and gas sector emissions as a priority to achieving its climate commitments. A regulatory framework was released in 2023 proposing a cap-and-trade system for the oil and gas industry under the Canadian Environmental Protection Act. Canadian provincial and federal climate policies, carbon pricing regulations and methane regulations, have financial and operating impacts on our Canadian business segment.

The United States has committed to reducing GHG emissions by 50-52% from 2005 levels by 2030 and reaching net zero by 2050. Methane regulations have been proposed with future policies aimed to reduce methane emissions including those from oil and gas operations under the Clean Air Act. In August 2022, the Inflation Reduction Act was approved which provides incentives for the implementation of methane mitigation and monitoring activities and proposes a price on methane for oil and gas facilities above a threshold. Final rules to reduce methane and other air pollutants from the oil and gas sector was released in December 2023. It is expected to result in a nearly 80 percent reduction in methane emissions from 2024 to 2038.

Carbon Pricing

In 2019, the Government of Canada implemented the federal Greenhouse Gas Pollution Pricing Act. The Act established a federal benchmark carbon pollution pricing system applied to fuel and combustible waste. The enacted federal carbon pricing impacts provincial jurisdictions that do not have an equivalent Output-Based Pricing System in place. The Provinces of Saskatchewan and Alberta, where Baytex operates, have performance standards in place which determine our financial exposure to the federal carbon pollution pricing system. Both provinces have obtained and must maintain federal equivalency for their programs. These provincial programs have associated compliance costs when performance standards, relative to an emissions benchmark, cannot be fully met. Compliance costs differ by province depending on the performance standard requirement and compliance cost rate. Emissions coverage includes stationary combustion from the implementation of the performance standards and expanding coverage to stationary combustion and flaring emissions in 2023.

Carbon pricing in Canada is currently set to $65 per tCO2e in 2023 and escalates $15 per tCO2e annually to $170 per tCO2e by 2030. There are direct costs of compliance fees in the performance standards, as well as inflationary influences on the cost of services and products as carbon pricing increases fuel costs for service providers. Registering our facilities in provincial performance standards limits the financial exposure of compliance fees. In 2022, regulatory reviews were completed on the provincial standards that outline the compliance rates and carbon pricing out to 2030.

In the Province of Saskatchewan, the Output-Based Performance Standard regulation applies to facilities emitting more than 25,000 tCO2e. We have elected to register our Kerrobert SAGD facility, even though it is under this threshold. The remainder of our facilities in Saskatchewan do not meet the large emitter criteria; however, we have opted into this provincial regulation by aggregating all of our other operated facilities. As a result our operated facilities are not subject to the federal carbon pollution pricing system. This provincial program requires a 8.33 percent reduction for 2023 and escalates 1.67% annually to an anticipated total 20% reduction by 2030, when compared to a 2019 baseline for stationary combustion and a 2020-2022 baseline for flaring. To the extent a company does not meet the required compliance rate reduction, annual compliance fees apply to the excess regulated emissions. The province matches the federal carbon pricing schedule out to 2030 and applies this price to the excess emissions.

In the Province of Alberta, the Technology Innovation and Emission Reduction regulation applies to facilities that emit more than 100,000 tCO2e. None of our facilities meet these criteria; however, we chose to opt into this provincial regulation by aggregating our operated facilities and as a result our operated facilities are not subject to the federal carbon pollution pricing system. The Alberta regulation requires an immediate 10% reduction from a 2020 benchmark and escalates 2% per year starting in 2023 to an anticipated 26% for fuel and 24% for flaring by 2030. To the extent a company does not meet the required reduction, annual compliance fees apply to the excess regulated emissions. The province matches the federal carbon pricing schedule out to 2030 and applies this price to the excess emissions. Regulatory compliance offset credits are generated in the provincial compliance programs if emissions are reduced beyond the annual compliance rate reduction requirement.

In 2022, the Inflation Reduction Act was passed into law in the United States. It imposes a fee on the emissions of methane from the oil and gas sector above a threshold. Beginning in 2024, the Waste Emission Charge on excess methane is proposed at US$36 per tonne of CO_2e ($900 per tonne of methane) rising to US$48 per tonne of CO_2e ($1,200 per tonne of methane) in 2025, and US$60 per tonne of CO_2e ($1,500 per tonne of methane) in 2026 and thereafter.

Methane Regulations

In 2018, Environment and Climate Change Canada set in place federal regulations for methane emissions from the oil and gas sector which came into force January 1, 2020. These regulations are set to achieve a methane reduction from upstream oil and gas facilities of 40-45% below 2012 levels by 2025. The Provinces take responsibility for energy and natural resources within their boundaries and have bodies to govern these activities. The Provinces of Alberta and Saskatchewan have developed GHG emissions reduction programs of their own, that have achieved equivalency under the federal regulations. These programs have increasing regulatory stringency in subsequent years and, if specified climate-related outcomes are not met, additional regulations could come into force. The Government of Canada has committed to expanding its oil and gas methane emissions reduction target to at least a 75% reduction below 2012 levels by 2030. In December 2023, a draft federal methane regulations for the oil and gas sector were released to achieve the 2030 target.

In the United States, air contaminants are the focus of current federal and Texas state standards, while methane rules are limited to new, modified, or reconstructed sites. In 2021, the EPA released its first methane proposal with final rules released in December 2023. It outlines nationwide emissions guidelines for states to limit methane emission from oil and gas. The development of state level plans or challenges to the finalized federal rules are anticipated.

Tightening methane regulations in future years may require retrofitting existing sites, equipment upgrades, GHG reduction project planning, capital investment, air monitoring and other reporting requirements. Additional future costs will be associated with equipment, projects, monitoring and reporting. We continue to monitor ongoing developments and proposed regulations to ensure regulatory compliance can be achieved.

Litigation

In addition, certain municipal entities and advocacy organizations have sued oil companies in the United States and threatened to sue oil companies in Canada for damage caused by climate change. Certain large oil companies have also been sued in the United States under securities laws for failing to disclose the risks associated with climate change. At this time we cannot anticipate if we will be included in any such litigation, whether the legal theories advanced in such lawsuits will be accepted by the courts or the potential impact of any such lawsuits.

Indigenous Rights

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

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

Occupational Health and Safety

The Corporation's operations must be carried out in accordance with safe work procedures, rules and policies contained in applicable safety legislation. Such legislation requires that every employer ensures the health and safety of all persons at any of its work sites and all workers engaged in the work of that employer. The legislation, which provides for incident reporting procedures, also requires every employer to ensure all of its employees are aware of their duties and responsibilities under the applicable legislation. Penalties under applicable occupational health and safety legislation include significant fines and incarceration.

General

Implementation of more stringent environmental regulations on our operations could affect the capital and operating expenditures and plans for our operations. In addition to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, water quality, fish, wildlife, visual quality, transportation, noise, spills, incidents and transportation.

We believe that, in all material respects, we are in compliance with, and have complied with, all applicable environmental laws and regulations. We have made and will continue to make expenditures in our efforts to comply with all applicable environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with governmental regulations. We believe that our continued compliance with existing requirements has been accounted for and will not have a material adverse impact on our financial condition, results of operations and operating cash flows. However, we cannot predict the passage of or quantify the potential impact of any more stringent future laws and regulations at this time.

DIVIDENDS

The Corporation began paying regular dividends to Shareholders on a quarterly basis as a part of the Corporation's return of capital framework announced in connection with the Ranger Merger. Commencing in third quarter of 2023, the Corporation began paying a quarterly dividend on the first business day of each quarter to Shareholders of record on the 15th day of the month prior to the payment date.

Although the Corporation strives to maintain consistent dividend payments, the amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including fluctuations in the price of oil and gas, exchange rates and production rates, reserves growth, the size of development drilling programs and the portion thereof funded from cash flow and the overall level of debt and working capital of the Corporation, the prevailing economic and competitive environment, the taxability of Baytex, Baytex's ability to raise capital, the amount of capital expenditures, the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends and other conditions existing from time to time. There can be no guarantee that Baytex will maintain the quantum or frequency of its dividends.

The agreements governing the Credit Facilities and Senior Notes provide that distributions to Shareholders and share repurchases are not permitted if the Corporation is in default under the agreements or the payment of such distribution would cause an event of default.

The following table sets forth the amount of cash dividends declared per Common Share by the Corporation for the periods indicated.

Declaration Date	Dividend $ per Common Share
July 27, 2023	0.0225
November 2, 2023	0.0225

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

Baytex is authorized to issue an unlimited number of Common Shares without nominal or par value and 10,000,000 Preferred Shares, without nominal or par value, issuable in series. As at the date of this AIF, there were no Preferred Shares outstanding.

The following is a summary of certain provisions of the share capital of Baytex. For a complete description of the share provisions, reference should be made to the Articles of Incorporation of Baytex, a copy of which is accessible on the SEDAR+ website at *www.sedarplus.com* (filed on January 10, 2011).

Common Shares

Holders of Common Shares are entitled to notice of meetings of the holders of Common Shares and to attend the meetings and to one vote per Common Share at such meetings (other than for meetings of a class or series of shares of the Corporation other than the Common Shares).

Holders of Common Shares will be entitled to receive dividends as and when declared by the Board, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of dividends.

Holders of Common Shares will be entitled in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Preferred Shares

Preferred Shares may be issued from time to time in one or more series, each series to consist of such number of shares as a may be authorized by the Board, and subject to the provisions of the ABCA, the Board may fix the rights, restrictions, privileges, conditions and designations attached to each series of Preferred Shares. The Preferred Shares shall be entitled to preference over the Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares with respect to payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, to the extent fixed in the case of each respective series, and may also be given such other preferences over the Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares as may be fixed in the case of each such series.

Senior Notes

On February 5, 2020, we issued US$500 million aggregate principal amount of 2027 Notes bearing interest at a rate of 8.75% per annum payable semi-annually. The 2027 Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 1, 2023 and will be redeemable at par from April 1, 2026 to maturity. As a result of repurchases and cancellations, as at December 31, 2023 US$410 million principal amount of the 2027 Notes remain outstanding.

On April 27, 2023, we issued US$800 million aggregate principal amount of 2030 Notes bearing interest at a rate of 8.50% per annum payable semi-annually. The 2030 Notes were issued at 98.709% of par and are redeemable at our option, in whole or in part, at specified redemption prices after April 30, 2026 and will be redeemable at par from April 30, 2028 to maturity.

For a complete description of the Senior Notes, reference should be made to the applicable debt indenture, copies of which are accessible on the SEDAR+ website at *www.sedarplus.com*. See *"Material Contracts"*.

Credit Facilities

Our Credit Facilities consist of US$1.1 billion of revolving credit facilities comprised of: (i) a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex; and (ii) a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex USA. The Credit Facilities are secured and, unless extended by the lenders, will mature on April 1, 2026.

For additional details regarding the covenants in our Credit Facilities and our compliance therewith, see the Baytex Annual 2023 MD&A. Also see *"Material Contracts"*.

Escrowed Securities and Securities Subject to Contractual Restriction

As at December 31, 2022, 56,297,330 Common Shares were subject to contractual restrictions on transfer as outlined in the table below.

Designation of Class	Number of Securities	% of Class
Common Shares (1)	56,297,330	6.85%

Note:

(1) All 56,297,330 of the restricted Common Shares are subject to a hold period agreement with an end date of March 16, 2024.

RATINGS

The following information relating to our credit ratings is provided as it relates to our financing costs, liquidity and operations. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. A reduction in our current credit ratings by the rating agencies, particularly a downgrade below the current ratings or a negative change in the ratings outlook, could adversely affect our cost of financing and our access to sources of liquidity and capital. In addition, changes in credit ratings may affect our ability and the associated costs to (i) enter into ordinary course derivative or hedging transactions and may require us to post additional collateral under certain of our contracts, and (ii) enter into and maintain ordinary course contracts with customers and suppliers on acceptable terms.

Credit Ratings Received as at the date of this AIF

	S&P Global Ratings ("**S&P**")	Moody's Investors Service ("**Moody's**")	Fitch Ratings ("**Fitch**")
Issuer Credit Rating	B+	Ba3	B+
Senior Unsecured Debt (Senior Notes)	BB-	B1	BB-

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt rated "B" is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitments on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, securities rated "B" are considered speculative and are subject to high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of its generic rating category. In addition, Moody's may add a rating outlook of "positive", "negative", "stable" or "developing" which assess the likely direction of an issuers rating over the medium term.

Fitch’s issuer credit ratings are on a rating scale that ranges from AAA to D which represents the range from highest to lowest quality. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within the major rating categories. An issuer credit rating of "B" by Fitch is within the sixth highest of eleven categories and indicates that material default risk is present, but a limited margin of safety remains. Financial commitments are currently being met; however, capacity for continued payment is vulnerable to deterioration in the business and economic environment. Fitch’s "stable" outlook indicates a low likelihood of a rating change over a one to two year period. Fitch’s ratings of individual securities are on a rating scale that ranges from AAA to C, which represents the highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show the relative standing within the major rating categories.

The credit ratings accorded to Baytex by S&P, Moody's and Fitch are not recommendations to purchase, hold or sell any of our securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will

remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

We have made payments to S&P, Moody's and Fitch in connection with the assignment of ratings to our long-term debt and may make payments to S&P, Moody's and Fitch in the future in connection with the confirmation of such ratings for purposes of the offering of debt securities. Other than the foregoing, no other payments were made to S&P, Moody's or Fitch in respect of any other service provided to the Corporation by such organization during the last two years.

MARKET FOR SECURITIES

The Common Shares are listed and trade on the TSX and the NYSE under the symbol "BTE". The following tables set forth the price range and trading volume of the Common Shares on the TSX and on all Canadian Exchanges ('Composite') for the periods indicated. The Common Shares began trading on the NYSE on February 23, 2023.

	Canada TSX Trading			Canada Composite Trading			US NYSE Trading		
	Price Range			Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High ($)	Low ($)	Volume Traded	High (US$)	Low (US$)	Volume Traded
2023									
January	6.16	5.54	54,957,236	6.16	5.54	98,934,966	4.63	4.1	5,098,258
February	6.17	5.26	76,926,419	6.17	5.26	143,237,173	4.625	3.87	23,937,189
March	5.64	4.37	145,405,501	5.68	4.37	247,339,258	4.15	3.2	74,766,072
April	5.45	4.92	68,237,598	5.45	4.92	131,864,314	4.09	3.6	30,921,285
May	5.05	4.28	70,709,931	5.05	4.28	142,786,494	3.56	3.16	43,163,142
June	4.71	3.90	123,971,487	4.71	3.93	240,182,633	3.54	2.95	170,503,250
July	5.32	4.22	91,400,930	5.32	4.22	162,375,368	4.04	3.14	109,838,821
August	5.60	5.21	81,261,554	5.60	5.21	149,677,283	4.18	3.81	90,491,260
September	5.99	5.44	107,288,759	5.99	5.44	197,607,527	4.41	4.02	198,673,606
October	6.31	5.26	111,895,613	6.31	5.26	224,783,940	4.6	3.83	180,091,993
November	6.23	5.16	114,937,885	6.24	5.16	213,024,495	4.53	3.77	206,170,230
December	5.14	4.20	96,131,695	5.14	4.20	193,527,280	3.64	3.1	168,641,816

DIRECTORS AND OFFICERS

Directors of the Corporation

The following table sets forth the name, municipality of residence, age as at December 31, 2023, year of appointment as a director of the Corporation and principal occupation for each of the directors of the Corporation.

Name and Municipality of Residence	Age	Director Since	Principal Occupation for Past Five Years
Mark R. Bly (1) Incline Village, Nevada	64	November 2017	Corporate director.
Tiffany Thom Cepak (3)(5) Friendswood, Texas	52	June 2023	Corporate director.
Trudy M. Curran (2)(4) Calgary, Alberta	61	July 2016	Corporate director. Previously, Interim Chief Executive Officer and managing director of Riversdale Resources from February 2019 to June 2019.
Eric T. Greager Denver, Colorado	54	November 2022	President and Chief Executive Officer of the Corporation since November 2022. Previously the President and Chief Executive Officer of Civitas Resources (formerly Bonanza Creek Energy, Inc.) from April 2018 to February 2022.
Don G. Hrap (3)(5) Houston, Texas	64	March 2020	Corporate director.
Angela S. Lekatsas (4)(5) Calgary, Alberta	62	February 2023	Corporate director. Previously, Chief Executive Officer of Cervus Equipment Corporation from May 2019 to October 2021 and prior thereto a director since October 2013.
Jennifer A. Maki (2)(5) North York, Ontario	53	September 2019	Corporate director.
David L. Pearce (2)(3) Calgary, Alberta	69	August 2018	Deputy Chairman, Azimuth Capital Management.
Stephen D.L. Reynish (3)(4) Calgary, Alberta	65	November 2020	Corporate director. Previously, President and Chief Executive Officer of Enlighten Innovations from October 2020 until October 2022. Formerly Executive Vice President at Suncor Energy Inc. from 2012 until 2020.
Jeffery Wojahn (2)(4) Denver, Colorado	61	June 2023	Corporate director. Previously, co-founder and Executive Chairman of MiddleFork Energy Partners, a privately held exploration and production company, from 2017 to 2020.

Notes:

(1) Chair of the Board and *ex officio* member of all board committees to which he is not appointed.

(2) Member of our Human Resources and Compensation Committee.

(3) Member of our Reserves and Sustainability Committee.

(4) Member of our Nominating and Governance Committee.

(5) Member of our Audit Committee.

Officers of the Corporation

The following table sets forth the name, municipality of residence, age as at December 31, 2023, position held with the Corporation and principal occupation of each of the officers of the Corporation.

Name and Municipality of Residence	Age	Office	Principal Occupation for Past Five Years
Eric T. Greager Denver, Colorado	54	November 2022	President and Chief Executive Officer of the Corporation since November 2022. Previously the President and Chief Executive Officer of Civitas Resources (formerly Bonanza Creek Energy, Inc.) from April 2018 to February 2022.
Chad L. Kalmakoff Calgary, Alberta	47	Chief Financial Officer	Chief Financial Officer of the Corporation since November 2022. Prior thereto, Vice President, Finance of the Corporation since September 2015.
Chad E. Lundberg Calgary, Alberta	42	Chief Operating Officer	Chief Operating Officer of the Corporation since June 2023. Prior thereto Chief Operating & Sustainability Officer since July 2021. Prior thereto Vice President, Light Oil since December 2018.
James R. Maclean Calgary, Alberta	44	Chief Legal Officer and Corporate Secretary	Chief Legal Officer and Corporate Secretary of the Corporation since June 2023. Prior thereto Vice President, General Counsel and Corporate Secretary since February 2022. Prior thereto General Counsel and Corporate Secretary since August 2018.
Brian G. Ector Calgary, Alberta	55	SVP, Capital Markets and Investor Relations	SVP, Capital Markets and Investor Relations of the Corporation since June 2023. Prior thereto Vice President, Capital Markets since August 2018. Prior thereto, an officer of the Corporation since June 2011.
Kendall D. Arthur Calgary, Alberta	43	SVP and General Manager, Cdn. Heavy Oil Operations	SVP and General Manager, Cdn. Heavy Oil Operations of the Corporation since June 2023. Prior thereto Vice President, Heavy Oil of the Corporation since December 2018. Prior thereto, a business unit Vice President with the Corporation since January 2012.
Julia Gwaltney Houston, Texas	52	SVP and General Manager, US Eagle Ford Operations	SVP and General Manager, US Eagle Ford Operations since June 2023. Previously, the SVP & Chief Operating Officer of Ranger Oil Corporation since January 2021. Additionally, served as Chief Operating Officer of Gary Permian, LLC, from November 2015 to January 2020.

Name and Municipality of Residence	Age	Office	Principal Occupation for Past Five Years
Nicole Frechette Calgary, Alberta	40	VP and General Manager, Cdn. Light Oil Operations	VP and General Manager, Cdn. Light Oil Operations of the Corporation since June 2023. Prior thereto Vice President, Light Oil since February 2022. Prior thereto Subsurface Manager, Light Oil since August 2021 and various senior technical and leadership roles with Repsol and Talisman Energy from 2005 until August 2021.
Chris M.P. Lessoway Calgary, Alberta	39	VP, Finance & Treasurer	Vice President of Finance and Treasurer of the Corporation since June 2023. Prior thereto Financial Controller starting from June 2017.

Ownership of Securities by Management

As at the date of this AIF, the directors and officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 4,957,497 Common Shares.

Conflicts of Interest

Certain of the directors and officers named above may be directors or officers of issuers or other companies which are in competition with the Corporation, and as such may encounter conflicts of interest in the administration of their duties with respect to the Corporation. In situations where conflicts of interest arise, the Corporation expects the applicable director or officer to declare the conflict and, if a director of the Corporation, abstain from voting in respect of such matters on behalf of the Corporation.

Corporate Cease Trade Orders or Bankruptcies

To the Corporation's knowledge, no director or executive officer of Baytex (nor any personal holding company of any of such persons) is, as of the date of this AIF, or was within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including Baytex), 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 disclosed below, to the Corporation's knowledge, no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to materially affect control of us, is, as of the date of this AIF, or has been within the ten years before the date of this AIF, a director or executive officer of any company (including Baytex) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold its assets or has, within the ten years before the date of this AIF, 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.

David Pearce is a director of Courser Energy Ltd. formerly Kaisen Energy Corp. ("Kaisen"). On December 8, 2021, Kaisen sought and obtained protection under the Companies' Creditors Arrangement Act

("CCAA") pursuant to an Order (the "Initial Order") of the Court of Queen's Bench of Alberta (the "Court"). The Initial Order authorized Kaisen to begin a Court-supervised restructuring and granted Kaisen various relief, including but not limited to, an initial stay of proceedings against Kaisen and its assets, appointing Ernst & Young Inc. as Monitor (the "Monitor"), and providing Kaisen the opportunity to prepare and file a plan of arrangement under the CCAA for the consideration of its creditors and other stakeholders. On December 17, 2021, the Court approved a plan of arrangement under the CCAA including provisions relating to receiving creditor and stakeholder approval for the plan of arrangement. On March 16, 2022, the Monitor filed a Plan Implementation Certificate confirming that the Plan, as approved by affected creditors and the Court is effective in accordance with its terms and the Sanction Order. As a result, the CCAA proceedings have now concluded and the Monitor has been discharged.

Trudy Curran, a director of Baytex, was a director of Great Panther Mining Ltd. ("Great Panther") from June 9, 2021 to December 15, 2022. On September 6, 2022, Great Panther filed a notice of intention to make a proposal under the Bankruptcy and Insolvency Act (Canada), which provided Great Panther with creditor protection while it sought to restructure its affairs. On November 18, 2022, the British Columbia Securities Commission issued a cease trade order in respect of Great Panther's securities as a result of its inability to file its quarterly continuous disclosure documents in accordance with Canadian securities laws. On December 16, 2022, Great Panther made a voluntary assignment into bankruptcy under the Bankruptcy and Insolvency Act (Canada) and Alvarez & Marsal Canada Inc. was appointed licensed insolvency trustee of Great Panther's estate.

Penalties or Sanctions

To the Corporation's knowledge, no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to materially affect 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

There are potential conflicts of interest to which the directors and officers of Baytex will be subject in connection with the operations of Baytex. In particular, certain of the directors and officers of Baytex are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Baytex or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Baytex. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director will disclose his interest in such contract or agreement and will refrain from voting on any matter in respect of such contract or agreement unless otherwise provided in the ABCA.

Our audit committee is responsible for reviewing all related party transactions and its mandate specifies that the audit committee is responsible for ensuring the nature and extent of such transactions are properly disclosed.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The text of the Audit Committee's Mandate and Terms of Reference is attached as Appendix C to this AIF.

Composition of the Audit Committee

The members of our Audit Committee are Jennifer A. Maki, Don G. Hrap, Angela S. Lekatsas and Tiffany Thom Cepak. The relevant education and experience of each Audit Committee member is outlined below:

Name	Relevant Education and Experience
Jennifer A. Maki [1][2][3] *Committee Chair*	Bachelor of Commerce degree from Queen's University and a postgraduate diploma from the Institute of Chartered Accountants of Ontario. Formerly served as CEO of Vale Canada and Executive Director of Vale-SA-Base Metals. Prior thereto, CFO and Executive Vice President, of Vale-SA-Base Metals. Before joining Vale/Inco, worked at PricewaterhouseCoopers LLP for 10 years.
Don G. Hrap [1][2]	Bachelor of Science in Mechanical Engineering and a Master in Business Administration. From 2009-2018, he served as President, Lower 48 at ConocoPhillips with strong breadth and depth of experience across several U.S. oil resource plays. Prior to this at ConocoPhillips, Mr. Hrap was senior vice president of Western Canada Gas. He joined ConocoPhillips in 2006 through the merger with Burlington Resources, serving as senior vice president of operations for Burlington Canada. Earlier, he was vice president for the North American Division at Gulf Canada Resources, where he worked for 17 years.
Angela S. Lekatsas [1][2][3]	Bachelor of Commerce Degree (Major in Accounting) from the University of Saskatchewan, post-graduate Chartered Professional Accountant designation from the Institute of Chartered Accountants of Alberta, and U.S. Certified Public Accountant equivalency from the Illinois Board of Examiners (inactive). She also holds the ICD.D designation from the Institute of Corporate Directors. Ms. Lekatsas spent 20 years in industry as the former President and CEO of Cervus Equipment Corporation and served in various executive roles with Nutrien Inc. and its predecessor company Agrium Inc. Prior thereto Ms. Lekatsas practiced public accounting for 16 years during which time she advocated for the accounting and auditing profession in various provinces sitting on Institute Committees such as the Professional Conduct and Financial Institutions Committees, acting as a guest lecturer as well sitting as an elected member of the ICAM Board
Tiffany Thom Cepak [1][2][3]	Ms. Cepak holds a B.S. in Engineering from the University of Illinois and a Master of Business Administration in Management with a concentration in Finance from Tulane University. Formerly served as Chief Financial Officer for Energy XXI Gulf Coast Inc., from August 2017 to October 2018. Prior to that, a CFO at KLR Energy Acquisition Corp., from January 2015 to June 2017. Additionally, the CFO of EPL Oil & Gas, Inc. for four years until it was sold in 2014.

Notes:

(1) Independent director.

(2) Financially literate within the meaning of National Instrument 52-110 - Audit Committees and the NYSE listing standards.

(3) An "Audit Committee Financial Expert" pursuant to the SEC's definition of the term.

Pre-Approval of Policies and Procedures

Although the Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services by our auditors, it does pre-approve all non-audit services to be provided to us and our subsidiaries by the external auditors. The pre-approval for recurring services, such as preliminary work on the integrated audit, securities filings, translation of our financial statements and related MD&A into the French language and tax and tax-related services, is provided on an annual basis and other services are subject to pre-approval as required.

External Auditor Service Fees

The following table provides information about the fees billed to us and our subsidiaries for professional services rendered by our external auditors, during fiscal 2023 and 2022:

Year	Audit Fees [1]	Audit-Related Fees [2]	Tax Fees [3]	All Other Fees [4]	Total
2023	$ 2,234	$ —	$ —	$ —	$ 2,234
2022	$ 1,145	$ —	$ —	$ —	$ 1,145

Notes:

(1) Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. In addition to the fees for annual audits of financial statements and review of quarterly financial statements, services in this category for fiscal 2023 and 2022 also include amounts for audit work performed in relation to the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 relating to internal control over financial reporting.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as Audit Fees.

(3) Tax fees include fees for tax compliance, tax advice and tax planning.

(4) Other fees include all other non-audit services.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Other than as disclosed below, 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.

In June 2016, certain indirect subsidiary entities received reassessments from the CRA that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. Following objections and submissions, in November 2023 the CRA issued notices of confirmation regarding their prior reassessments. In February 2024, Baytex filed notices of appeal with the Tax Court of Canada and we estimate it could take between two and three years to receive a judgment. The reassessments do not require us to pay any amounts in order to participate in the appeals process. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

We remain confident that the tax filings of the affected entities are correct and are vigorously defending our tax filing positions. In addition, we have purchased $272.5 million of insurance coverage to help manage the litigation risk associated with this matter. The expenses incurred to purchase the insurance coverage were approximately $51 million. The most recent reassessments issued by the CRA assert taxes owing by the trusts (described below) of $244.8 million, late payment interest of $166.6 million and a late filing penalty in respect of the 2011 tax year of $4.1 million.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (the "Losses"). The Losses were subsequently deducted in computing the taxable income of those trusts. The reassessments, as confirmed in November 2023, disallow the deduction of the Losses for two reasons. Firstly, the reassessments allege that (i) the trusts were resettled, and (ii) the resulting successor trusts were not able to access the losses of the predecessor trusts. Secondly, the reassessments allege that the general anti-avoidance rule of the *Income Tax Act* (Canada) operates to deny the deduction of the losses. If, after exhausting available appeals, the deduction of Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potentially penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to those/that taxpayer(s) to offset the reassessed income, including tax shelter from future years that may be carried back and applied to prior years.

INTEREST OF INSIDERS AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of our directors and executive officers, any holder of Common Shares who beneficially owns or controls or directs, directly or indirectly, more than 10 percent of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transactions within the three most recently completed financial years or since the beginning of our last completed financial year which has materially affected or is reasonably expected to materially affect us.

TRANSFER AGENT AND REGISTRAR

Odyssey Trust Company, at its principal offices in Calgary, Alberta, Vancouver, British Columbia and Toronto, Ontario, is the transfer agent and registrar for the Common Shares in Canada. Odyssey Transfer US Inc., at its principal office in Denver, Colorado is the transfer agent and registrar for the Common Shares in the United States. Computershare Trust Company, N.A., at its principal office in Canton, Massachusetts, is the transfer agent and registrar for the senior Notes.

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 are still material and are still in effect, are the following:

a. the third amended and restated credit agreement in respect of the Credit Facilities and the subsequent clarification amending agreement (both filed on SEDAR+ on January 11, 2024) ;

b. 2020 Debt Indenture (filed on SEDAR+ on February 10, 2020);

c. 2023 Debt Indenture (filed on SEDAR+ on April 28, 2023);

d. our share award incentive plan (filed on SEDAR+ on April 18, 2016) and our subsequently amended share award incentive plan (filed on January 28, 2018, March 1, 2022 and February 23, 2023) and

e. our investor and registration rights agreement (filed on SEDAR+ on March 1, 2023).

Copies of each of these contracts are accessible on the SEDAR+ website at *www.sedarplus.com*.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 - Continuous Disclosure Obligations by us during, or related to, our most recently completed financial year other than McDaniel, our independent qualified reserves evaluator. 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 a report, valuation, statement or opinion, at any time thereafter or to be received by them.

KPMG LLP are the auditors of the Corporation and have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations, and also that they are independent accountants with respect to the Corporation under all relevant US professional and regulatory standards.

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 Baytex or of any associate or affiliate of Baytex.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our website and on the SEDAR+ website at *www.sedarplus.com*. Further information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our Information Circular - Proxy Statement for the annual meeting of Shareholders. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2023 and the related Baytex Annual 2023 MD&A which are accessible on the SEDAR+ website at *www.sedarplus.com*.

For additional copies of this AIF and the materials listed in the preceding paragraph, please contact:

Baytex Energy Corp.
Suite 2800, Centennial Place, East Tower
520 – 3rd Avenue S.W.
Calgary, Alberta T2P 0R3
Phone: (587) 952-3000
Fax: (587) 952-3029
Website: *www.baytexenergy.com*

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Form 51-101F3

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

Independent qualified reserves evaluators have evaluated Baytex's reserves data. The report of the independent qualified reserves evaluators is presented below.

The Reserves and Sustainability Committee of the Board of Directors of Baytex (the "**Reserves Committee**") has:

a. reviewed Baytex's procedures for providing information to the independent qualified reserves evaluators;

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

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

The Reserves Committee has reviewed Baytex'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 of Baytex 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 evaluators on the reserves data; and

c. the content and filing of this report.

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

(signed) *"Eric T. Greager"*
Eric T. Greager
President and Chief Executive Officer

(signed) *"Chad L. Kalmakoff"*
Chad L. Kalmakoff
Chief Financial Officer

(signed) *"Don G. Hrap"*
Don G. Hrap
Director and Chair of the Reserves and Sustainability Committee

(signed) *"David L. Pearce"*
David L Pearce
Director and Member of the Reserves and Sustainability Committee

February 28, 2024

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Form 51-101F2

To the Board of Directors of Baytex Energy Corp. ("Company"):

1. We have evaluated the Company's reserves data as at December 31, 2023. The reserves data is an estimate 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 estimated future net revenue (before deduction of income taxes) attributed to proved + 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 Company's Board of Directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) (in $ thousands)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates	December 31, 2023	Canada	—	2,888,697.3	—	2,888,697.3
McDaniel & Associates	December 31, 2023	United States	—	4,911,444.8	—	4,911,444.8
TOTALS				7,800,142.1		7,800,142.1

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

7. We have no responsibility to update the report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.

8. Because the reserves data is based on judgments 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.

(signed) *"Brian R. Hamm"*

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

Calgary, Alberta
February 1, 2024

APPENDIX C

BAYTEX ENERGY CORP.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

ROLE AND OBJECTIVE

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Baytex Energy Corp. (the "Corporation") to which the Board has delegated certain of its responsibilities. The primary responsibility of the Committee is to review the interim and annual financial statements of the Corporation and to recommend their approval or otherwise to the Board. The Committee is also responsible for reviewing and determining, in its capacity as a committee of the Board, the appointment and compensation of the external auditors of the Corporation, overseeing the work of the external auditors, including the nature and scope of the audit of the annual financial statements of the Corporation, pre-approving services to be provided by the external auditors and reviewing the assessments prepared by management and the external auditors on the effectiveness of the Corporation's internal controls over financial reporting. The objectives of the Committee are to assist the Board in monitoring and overseeing:

1. the preparation and disclosure of the financial statements of the Corporation and related matters;
2. communication between directors and the external auditors;
3. the external auditors' qualifications and independence;
4. compliance with legal and regulatory requirements;
5. the performance of the Corporation's external auditor;
6. the integrity, credibility and objectivity of financial reports and statements; and
7. the relationship among the Committee, all independent directors, management and the external auditors.

MEMBERSHIP OF THE COMMITTEE

1. The Committee shall be comprised of not less than three members all of whom are "independent" directors and "financially literate" within the meaning of National Instrument 52-110 "Audit Committees" and the laws, rules and regulations of the U.S. Securities and Exchange Commission ("SEC") and the New York Stock Exchange ("NYSE"), as applicable, subject to any permitted phase-in periods that may apply. The members of the Committee shall be appointed by the Board from time to time based on the recommendation of the Nominating & Governance Committee.

2. At least one member of the Committee shall have accounting or related financial management expertise, as the Board interprets such qualification in its business judgment. For certainty, any member of the Committee that qualifies as an "audit committee financial expert" under the rules of the SEC will be deemed to meet this requirement. Members of the Committee may not be "affiliates" of the Corporation or any subsidiary of the Corporation. Subject to any permitted exceptions, members of the Committee may not accept, directly or indirectly, any consulting, advisory, or other compensatory fee from the Corporation or any subsidiary thereof. Corporation

3. A member of the Committee may not simultaneously serve on the audit committees of more than three public companies, unless the Board first determines that such simultaneous service would not impair the ability of such member to effectively serve on the Committee. Any such determination must be publicly disclosed in accordance with the rules of the NYSE.

4. The Board shall appoint a Chair of the Committee, who shall be an independent director.

5. Any member of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders of the Corporation following appointment as a member of the Committee.

MANDATE AND RESPONSIBILITIES OF THE COMMITTEE

1. It is the responsibility of the Committee to:
    a. recommend the firm of chartered accountants to be nominated as the Corporation's auditors, for approval by the shareholders of the Corporation; and
    b. oversee the planning and staffing of the audit by the external auditor. The external auditors shall report directly to the Committee.

2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to the Corporation's internal control systems by:
    a. identifying, monitoring and mitigating business risks; and
    b. ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review with management and the external auditors the interim and annual financial statements of the Corporation, including disclosures made under "Management's Discussion and Analysis", prior to their submission to the Board for approval. The review process should include, without limitation:
    a. reviewing major issues regarding accounting policies and principles and financial statement presentations, including any changes in accounting principles, or in their application;
    b. reviewing major issues as to the adequacy of the Corporation's internal controls and any special audit steps adopted in light of material control deficiencies;
    c. reviewing significant management judgments, estimates and assumptions that affect the application of accounting policies and their reported amounts;
    d. reviewing analyses prepared by management and/or the external auditors setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative GAAP methods on the financial statements;
    e. reviewing accounting treatment of unusual or non-recurring transactions;
    f. ascertaining compliance with covenants under loan agreements;
    g. reviewing disclosure requirements for commitments and contingencies;
    h. reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    i. reviewing unresolved differences between management and the external auditors;
    j. reviewing the type and presentation of information to be included in the Corporation's earnings press releases (paying particular attention to any use of "pro forma" or "adjusted" non-GAAP information prior to their public release);
    k. reviewing the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the financial statements of the Corporation;
    l. obtaining explanations of significant variances with comparative reporting periods; and
    m. determining through inquiry if there are any related party transactions and ensuring that the nature and extent of such transactions are properly disclosed.

4. The Committee is to review all public disclosure of audited or unaudited financial information by the Corporation before its release (and, if applicable, prior to its submission to the Board for

approval), including the interim and annual financial statements of the Corporation, management's discussion and analysis of results of operations and financial condition, earnings press releases, the annual information form and any annual report filed with the U.S. Securities and Exchange Commission. The Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of financial information and shall periodically assess the accuracy of those procedures.

5. The Committee shall discuss the Corporation's earnings press releases, as well as financial information and earnings guidance provided to analysts and rating agencies, recognizing that this review and discussion may be done generally (consisting of a discussion of the types of information to be disclosed and the types of presentations to be made).

6. With respect to the external auditors of the Corporation, the Committee shall:
    a. in its capacity as a committee of the Board, be directly responsible for the compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the listed issuer, including the terms of their engagement for the integrated audit;
    b. review and approve any other services to be provided by the external auditors (including the fee for such services) as detailed below;
    c. when there is to be a change in the external auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;
    d. at least annually, review the qualifications, performance and independence of the external auditors including a) review the experience and qualifications of the senior members of the external auditors' team; b) confirm with the external auditors that it is in compliance with applicable legal, regulatory and professional standards relating to auditor independence; c) review annual reports from the external auditors regarding its independence and consider whether there are any non-audit services or relationships that may affect the objectivity and independence of the external auditors and, if so, recommend to the Board to take appropriate action to satisfy itself of the independence of the external auditor; and obtain and review such reports from the external auditors as may be required by applicable legal and regulatory requirements;
    e. at least annually, obtain and review a report by the external auditors describing the firm's internal quality-control procedures; any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues; and (to assess the external auditors' independence) all relationships between the external auditors and the Corporation;
    f. review with the external auditors any problems or difficulties the external auditors may have encountered during the provision of its audit services and management's response, including any restrictions on the scope of activities or access to the requested information and any significant disagreements with management;
    g. review and evaluate the lead partner of the external auditor;
    h. ensure the regular rotation of the lead audit partner as required by law, and consider whether, in order to assure continuing external auditor independence, there should be regular rotation of the audit firm itself. The Committee should present its conclusions with respect to the external auditors to the full Board.

7. Periodically review with management the need for an internal audit function.

8. Review with the external auditors their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response

and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for the audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

9. The Committee must pre-approve all services to be provided to the Corporation or its subsidiaries by the external auditors. In pre-approving any service, the Committee shall consider the impact that the provision of such service may have on the external auditors' independence. The Committee may delegate to one or more of its members the authority to pre-approve services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with applicable laws, rules and regulations and such other procedures as may be established by the Committee from time to time.

10. The Committee shall review the risk assessment and risk management policies and procedures of the Corporation used to identify, manage and control the principle business risks facing the Corporation which is to include reviewing with management:

    a. foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments and compliance with the Corporation's Hedging Instruments Risk Management Policy;

    b. the insurance coverages maintained by the Corporation;

    c. any legal claims or other contingency, including tax assessments that could have a material effect on the financial position or operation results of the Corporation; and

    d. the adequacy of the security measures that are in place in respect of the Corporation's information systems and the information technology utilized by the Corporation.

11. The Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by employees of the Corporation and its subsidiary entities of concerns regarding questionable accounting or auditing matters.

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

13. The Committee shall have the authority to investigate any financial activity of the Corporation. All employees of the Corporation and its subsidiary entities are to cooperate as requested by the Committee.

14. The Committee shall forthwith report any issues arising in connection with its duties, the results of meetings and reviews undertaken and any associated recommendations to the Board.

15. The Committee shall meet with the external auditors at least four times per year (in connection with their review of the interim and annual financial statements) and at such other times as the external auditors and the Committee consider appropriate.

MEETINGS AND ADMINISTRATIVE MATTERS

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

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

5. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

6. The Committee may invite those officers, directors and employees of the Corporation and its subsidiary entities 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, provided that the Chief Financial Officer of the Corporation shall attend all meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair of the meeting.

7. Minutes of the Committee's meetings will be recorded and maintained and made available to any director who is not a member of the Committee upon request.

8. The Audit Committee shall meet periodically with management and the independent auditor in separate executive sessions.

9. The Committee shall conduct an annual evaluation of its performance in fulfilling its duties and responsibilities under this mandate, and shall assess the adequacy of the reporting and information provided by management to support the Committee’s oversight responsibilities.

10. The Committee may retain persons having special expertise and/or obtain independent professional advice, including, without limitation, independent counsel or other advisors, as it determines necessary to carry out its duties, at the expense of the Corporation.

11. The Corporation shall provide appropriate funding, as determined by the Committee, in its capacity as a committee of the Board, for payment of (i) compensation to any external auditors engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation; (ii) compensation to any advisors employed by the Committee; and (iii) ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

12. Any issues arising from the Committee's meetings that bear on the relationship between the Board and management should be communicated to the Chair of the Board or the Lead Independent Director, as applicable, by the Committee Chair.

13. At least annually, the Committee shall, in a manner it determines to be appropriate, review and assess the adequacy of its mandate and recommend to the Board of Directors any improvements to this mandate that the Committee determines to be appropriate.

Approved by the Board of Directors on February 13, 2023