UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

☐ **Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934**

☒ **Annual Report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended: December 31, 2022
Commission File Number: 001-32754

BAYTEX ENERGY CORP.
(Exact name of Registrant as specified in its charter)

Alberta	**1381**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

2800, 520 - 3rd Avenue S.W.
Calgary, Alberta
T2P 0R3
(587) 952-3000
(Address and telephone number of registrant's principle executive offices)

Capitol Corporate Services, Inc.
206 E. 9th St., Ste 1300
Austin, Texas 78701
(800) 345-4647
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Trading Symbol(s)**	**Name of each exchange on which registered**
Common Shares	BTE	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None

For annual reports, indicate by check mark the information filed with this form:
☒ Annual Information Form ☒ Audited Annual Financial Statements

Indicate the number of outstanding shares of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: 544,930,072

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes ý No ¨

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act. ☐ Emerging growth company

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

† The term “new or revised financial accounting standard” refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark whether the registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ¨

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 40-F are forward-looking statements within the meaning of Section 21E of the Securities and Exchange Act of 1934, as amended (the "Exchange Act") and Section 27A of the Securities Act of 1933, as amended. Please see section titled "Special Note Regarding Forward-Looking Statements" in the Annual Information Form, which is Exhibit 99.1 of this Annual Report on Form 40-F.

Principal Documents

The following documents are filed as part of this Annual Report on Form 40-F:

A. Annual Information Form

For the Registrant's Annual Information Form for the year ended December 31, 2022, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2022, including the report of its Independent Registered Public Accounting Firm with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F.

C. Management's Discussion and Analysis

For the Registrant's Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2022, see Exhibit 99.3 of this Annual Report on Form 40-F.

Controls and Procedures

A. Certifications

The required disclosure is included in Exhibits 99.4, 99.5, 99.6 and 99.7 of this Annual Report on Form 40-F.

B. Disclosure Controls and Procedures

As of the end of the Registrant's fiscal year ended December 31, 2022, an internal evaluation was conducted under the supervision of and with the participation of the Registrant's management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Registrant's "disclosure controls and procedures" (as defined in Rule 13a-15(e) under Exchange Act). Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of the Registrant's disclosure controls and procedures were effective to ensure that the information required to be disclosed in the reports that the Registrant files or submits to the Securities and Exchange Commission is (i) recorded, processed, summarized and reported, within the required time periods; and (ii) accumulated and communicated to the Registrant's management, including the President and Chief Executive Officer and the Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant's disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

C. Management's Annual Report on Internal Control Over Financial Reporting

Management's Annual Report on Internal Control Over Financial Reporting is included in the Management's Report that accompanies the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2022, filed as Exhibit 99.2 to this Annual Report on Form 40-F, and is incorporated herein by reference.

D. Attestation Report of Independent Registered Public Accounting Firm

The Attestation Report of the Registrant's Auditor is included in the Report of Independent Registered Public Accounting Firm that accompanies the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2022, filed as Exhibit 99.2 of this Annual Report on Form 40-F, and is incorporated herein by reference.

E. Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2022, there were no changes in the Registrant's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting.

Audit Committee Financial Expert

The Registrant's Board of Directors has determined that Ms. Jennifer Maki and Mr. Gregory Melchin are "audit committee financial experts" (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) and are "independent" (as defined by the New York Stock Exchange corporate governance rules).

The Securities and Exchange Commission has indicated that the designation or identification of a person as an “audit committee financial expert” does not (i) mean that such person is an “expert” for any purpose, including without limitation for purposes of Section 11 of the Securities Act of 1933, (ii) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the audit committee and the board of directors in the absence of such designation or identification, or (iii) affect the duties, obligations or liability of any other member of the audit committee or the board of directors.

Code of Ethics

The Registrant has adopted a "code of ethics" (as that term is defined in paragraph 9(b) of General Instruction B to Form 40-F) ("Code of Ethics"), which is applicable to the directors, officers, employees and consultants of the Registrant and its affiliates (including, its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions). The Code of Ethics is available on the Registrant's website at www.baytexenergy.com.

In the past fiscal year, the Registrant has not amended any provision of its Code of Ethics that relates to any element of the code of ethics definition enumerated in paragraph (9)(b) of General Instruction B to Form 40-F, or granted any waiver, including an implicit waiver, from any provision of its Code of Ethics.

If any amendment to the Code of Ethics is made, or if any waiver from the provisions thereof is granted, the Registrant may elect to disclose the information about such amendment or waiver required by Form 40-F to be disclosed, by posting such disclosure on the Registrant's website, which may be accessed at www.baytexenergy.com.

Principal Accountant Fees and Services

The required disclosure is included under the heading "Audit Committee Information - External Auditor Service Fees" in the Registrant's Annual Information Form for the year ended December 31, 2022, filed as Exhibit 99.1 to this Annual Report on Form 40-F, and is incorporated herein by reference. Our independent registered public accounting firm is KPMG LLP, Calgary, Alberta, Canada, Auditor Firm ID: 85.

Off-Balance Sheet Arrangements

The Registrant does not have any "off-balance sheet arrangements" (as that term is defined in paragraph 11(ii) of General Instruction B to Form 40-F) that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Cash Obligations

The required disclosure is included under the heading "Capital Resources and Liquidity" and subheading "Contractual Obligations" in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2022, filed as Exhibit 99.3 to this Annual Report on Form 40-F, and is incorporated herein by reference.

Identification of the Audit Committee

The Registrant has a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The Registrant's Audit Committee members consist of Ms. J. Maki , Mr. G. Melchin and Mr. D. Hrap.

Mine Safety Disclosure

Not applicable.

Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

Recovery of Erroneously Awarded Compensation

Not applicable.

UNDERTAKING

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

(1) The Registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

(2) Any change to the name or address of the Registrant's agent for service shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of the Registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this report to be signed on its behalf by the undersigned, thereto duly authorized on February 23, 2023.

BAYTEX ENERGY CORP.

By: */s/ Chad L. Kalmakoff*

Name: Chad L. Kalmakoff

Title: Chief Financial Officer

EXHIBIT INDEX

Exhibit No.	Document
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2022.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2022 together with the Auditors' Report thereon.
99.3	Management's Discussion and Analysis of the operating and financial results of the Registrant for the year ended December 31, 2022.
99.4	Certification of Chief Executive Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.5	Certification of Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.6	Certification of Chief Executive Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.7	Certification of Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.8	Consent of KPMG LLP, Independent Registered Public Accounting Firm.
99.9	Consent of McDaniel & Associates Consultants Ltd., independent engineers.
99.10	Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited).
101	Interactive Data Files.

Exhibit 99.1



ANNUAL INFORMATION FORM

2022

February 23, 2023

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APPENDICES:

APPENDIX A REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

APPENDIX B REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

APPENDIX C AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

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.

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.

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.

2021 Notes means the 5.125% senior unsecured notes due June 1, 2021 issued by Baytex pursuant to the 2014 Debt Indenture which were redeemed as of February 20, 2020.

2022 Debentures means the 6.625% series C senior unsecured debentures due July 19, 2022 which were redeemed as of March 5, 2020.

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 or Senior Notes means the 8.750% senior unsecured notes due April 1, 2027 issued by Baytex pursuant to the 2020 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 23, 2023 for the year ended December 31, 2022.

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.

Credit Facilities means our US$850 million secured covenant-based revolving credit facilities with a syndicate of financial institutions.

Common Shares means the common shares of Baytex.

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.

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.

Independent Engineering

Baytex Reserves Report means the report of McDaniel dated February 2, 2023 entitled "Baytex Energy Corp., Evaluation of Petroleum Reserves, Based on Forecast Prices and Costs, As of December 31, 2022".

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, from a given date forward, based on:

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

(b) the use of established technology; and

(c) specified economic conditions (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:

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

(ii) 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
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
NYMEX	the New York Mercantile Exchange
AECO	the natural gas storage facility located at Suffield, Alberta
MEH	Magellan East Houston
MSW	Mixed Sweet Blend
WTI	West Texas Intermediate
WCS	Western Canadian Select
$ 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 2023 guidance for exploration and development expenditures and production; our five-year outlook including expected production, production growth and annual capital spending; our intentions of allocating our annual free cash flow to shareholder returns through share buybacks and debt reduction; our goal of building value by developing our assets and completing selective acquisitions; our commitment to restoring our 2020 we-of-life well inventory to zero and the anticipated timing thereof; our short-term diversity target 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 2023; development plans for our properties; undeveloped lease expiries; when we expect to pay material income taxes; our working interest production volume for 2023 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; and our assessment of our tax filing position for the years 2011 through 2015.

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 volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; 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; 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; 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 of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; 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; the risk that we may not have sufficient financial resources in the future to provide shareholder returns; 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 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 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 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.

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 2023 guidance for development expenditures; our five-year outlook including our expected annual capital spending; our intentions of allocating our annual free cash flow to shareholder returns through a share buyback and debt reduction; 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.

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, 2022. The Corporation is required to reassess this conclusion annually, at the end of the second quarter.

Access to Documents

Any document referred to in this AIF and described as being accessible on the SEDAR website at *www.sedar.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 – 3 rd 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".

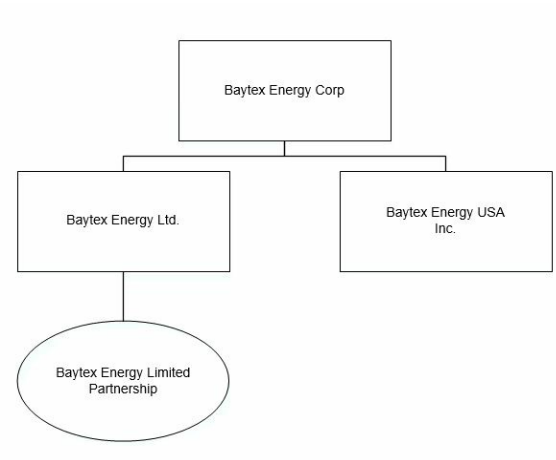
Inter-Corporate Relationships

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

2020

2020 was an extremely challenging year. The spread of Covid-19 and the associated decrease in demand for crude oil combined with a decision by the members of OPEC to increase the supply of crude oil resulted in a significant reduction in commodity prices. Commodity prices increased from their lows following a production curtailment agreement between members of the OPEC+ group to limit supply, but remained below their previous levels as a result of decreased demand associated with continued efforts to limit the spread of Covid-19. The price for WTI averaged US$39.40/bbl for the year.

Prior to the market dislocations caused by the spread of Covid-19 we entered into a series of transactions to extend the maturity dates of our outstanding indebtedness. On February 5, we issued US$500 million principal amount of 2027 Notes. The proceeds of this issuance, along with available cash and liquidity available under our Credit Facilities, were used to redeem our US$400 million principal amount 2021 Notes on February 2020 and our $300 million principal amount 2022 Debentures on March 5, 2020. In addition, on March 2, 2020 we extended the maturity of our Credit Facilities to April 2, 2024. Following these transactions the nearest maturity date of our senior unsecured debt and Credit Facilities was extended from 2021 to 2024.

In response to decreased commodity prices, we took decisive steps to adjust our business model. We reduced our capital budget by 50% and shut-in approximately 25,000 boe/d of production for a portion of the year. As a result, production for the year ended December 31, 2020 averaged 79,781 boe/d, which was comprised of 18,143 bbl/d of light and medium crude oil, 18,629 bbl/d of heavy crude oil, 2,513 bbl/d of bitumen, 13,798 bbl/d of tight oil, 12,455 bbl/d of NGL, 44,299 mcf/d of shale gas and 41,165 mcf/d of conventional natural gas, while exploration and development expenditures were $280 million.

On December 2, 2020, we announced our anticipated 2021 exploration and development expenditures range of $220-275 million designed to generate average annual production of 73,000-77,000 boe/d, which reflected the re-set of our business that occurred in 2020.

On March 24, 2020, we received a continued listing standards notice from the NYSE as the average closing price for our Common Shares was less than US$1.00 per share over a period of 30 consecutive trading days. Subsequently, on December 3, 2020, our Common Shares were delisted from the NYSE. Baytex's Common Shares continued to trade on the TSX.

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 the OPEC+ group 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 senior unsecured notes due June 2024.

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 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. See "*Description of Capital Structure – Credit Facilities*".

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 June 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 Advisor to the Board and Chief Executive Officer until February of 2023.

On November 17, 2022 Baytex 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 decreased to $800 million we would increase direct shareholder returns to 50% of free cash flow and an ultimate debt target.

Subsequent to year-end 2022

On February 23, 2023 Baytex's Commons Shares commenced trading on the NYSE under the symbol BTE.

(1) Capital management measure. See "Specified Financial Measures" in the Annual 2022 MD&A for information related to this measure, which section has been incorporated by reference herein. The Annual 2022 MD&A is available on SEDAR at www.sedar.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 84% of our production is weighted toward crude oil and NGLs. The Corporation and its predecessors have been in business for more than 25 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.

Competitive Conditions

Baytex is a member of the oil and natural gas industry, which is highly competitive. Baytex competes with other companies for all of its business inputs, including development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. We believe our competitive position is, on the whole, 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 every second year since 2012 and published our sixth report in July of 2022. 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. Highlights from our most recent report included that we:

- Reduced our corporate GHG intensity by 52% from our 2018 baseline and 11% below our 2020 levels.
- We completed 198 well abandonments in 2021, the most in company history and are committed to restoring our 2020 end-of-life well inventory of 4,500 wells to zero by 2040.
- We set a new short-term diversity target for our Board with the goal to reach 30% women Directors by our 2023 Annual General Meeting.

At the same time, we also released our first Task Force on Climate-Related Financial Disclosures ("TCFD") report. Highlights of our activities from the TCFD report included that we:

- Conducted an enterprise risk assessment with a focus on climate risks.
- Evaluated the qualitative impact of transition-related risks, and associated timeframes.
- Conducted qualitative transition scenario analysis using the IEA's Net Zero by 2050 and Announced Pledges scenarios.

- Conducted sensitivity analysis under various carbon prices and methane regulations.
- Completed third party reasonable assurance of our 2021 emissions.

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 2023 by the renegotiation or termination of any contracts to which we are a party.

Personnel

As at December 31, 2022, we had 157 employees in our head office and 65 employees in our 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, 2022. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2022 and production information represents average working interest production for the year ended December 31, 2022. All of our properties are located onshore.

Eagle Ford - Texas

Our Eagle Ford assets are located in the core of the liquids-rich Eagle Ford shale in South Texas. Our assets include non-operated working interests in approximately 78,212 (19,931 net) acres, comprised of four areas of mutual interest (Sugarloaf, Longhorn, Ipanema and Excelsior) with an average working interest of approximately 25%, together with field infrastructure and related assets. Our entire acreage position in the Eagle Ford is held by production and the assets are 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 in the area occurs from the hydraulic fracturing of horizontal wells.

During 2022, production from the Eagle Ford assets averaged approximately 28,245 boe/d, comprised of 22,720 bbl/d of light oil and medium crude, condensate and NGL and 33,146 Mcf/d of shale gas. During this period, Baytex participated in the completion of 68 (16.8 net) wells, resulting in 58 (13.1 net) oil wells

and 10 (3.7 net) natural gas wells. As at December 31, 2022, our proved plus probable reserves were 182 million boe (134 million proved; 47 million probable).

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 2022, the Viking assets produced 16,239 boe/d, comprised of 14,241 bbl/d of light and medium crude oil and NGL and 11,990 Mcf/d of natural gas. These assets are characterized by shallow wells with short cycle times and a manufacturing approach to development. In 2022, Baytex completed 132 (126.9 net) oil wells. As at December 31, 2022 we had proved plus probable reserves of 70 million boe (46 million proved; 24 million probable).

The undeveloped land base associated with the Viking assets consisted of 110,264 net acres at December 31, 2022.

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. However, a portion of Clearwater prospective acreage overlays our legacy Peace River lands which are productive from the Bluesky formation. Production in the area occurs through primary and polymer flooding recovery methods. During 2022, production from the area averaged approximately 20,212 boe/d, comprised of 18,208 bbl/d of heavy crude oil, 44 bbl/d of NGL and 11,752 Mcf/d of natural gas. In 2022, Baytex drilled 32 (32.0 net) horizontal multi-lateral wells in this area. As at December 31, 2022, we had proved plus probable reserves of 57 million boe (33 million proved; 24 million probable).

Baytex held approximately 272,681 net undeveloped acres in this area at December 31, 2022.

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 2022, production averaged approximately 11,064 boe/d, which was comprised of 9,022 bbl/d of heavy crude oil, 1,763 bbl/d of bitumen, 13 bbl/d of light and medium crude oil, and 1,602 Mcf/d of natural gas. In 2022, Baytex drilled 31 (28.1 net) oil wells in this area. As at December 31, 2022, we had proved plus probable reserves of 85 million boe (27 million proved; 59 million probable).

We held approximately 181,805 net undeveloped acres in this area at December 31, 2022.

Duvernay - Alberta

Baytex holds a large 100% working interest land position in the emerging East Duvernay resource play in central Alberta. Production in the area occurs from the hydraulic fracturing of horizontal wells. In 2022, the Duvernay assets produced 2,603 boe/d, comprised of 2,134 bbl/d of light oil and NGL and 2,812 Mcf/d of natural gas. During 2022, Baytex drilled 3 (3.0 net) oil wells. As at December 31, 2022, we had proved plus probable reserves of 31 million boe (16 million proved; 15 million probable) and net undeveloped lands totaled approximately 132,800 net acres.

Average Production

The following table indicates our average daily production from our principal properties for the year ended December 31, 2022.

	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)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy								
Peace River	18,208	—	—	—	44	—	11,752	20,212
Lloydminster	9,022	1,763	13	—	—	—	1,602	11,064
Total	27,230	1,763	13	—	44	—	13,354	31,276
Canada - Light								
Viking	—	—	14,000	—	241	—	11,990	16,239
Duvernay	—	—	—	1,244	890	2,812	—	2,603
Remaining properties	—	—	593	—	931	—	21,798	5,157
Total	—	—	14,593	1,244	2,062	2,812	33,788	23,999
United States								
Eagle Ford	—	—	—	13,979	8,741	33,146	—	28,245
Grand Total	**27,230**	**1,763**	**14,606**	**15,223**	**10,847**	**35,958**	**47,142**	**83,519**

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, 2022.

($000s)	Canada	United States	Total
Property acquisition costs			
Proved properties	551	—	551
Unproved properties	801	—	801
Property disposition	(25,649)	—	(25,649)
Total Property acquisition costs, net	(24,297)	—	(24,297)
Development Costs [1]	374,443	140,740	515,183
Exploration Costs [2]	6,359	—	6,359
Total	356,505	140,740	497,245

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, 2022.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	743	637.6	1,283	837.5	331	247.2	581	447.6
BC	—	—	—	—	1	0.5	1	0.5
Saskatchewan	2,817	2,574.1	1,757	1,700.6	479	391.2	397	362.8
Texas	968	220.1	55	13.1	401	113.4	19	3.9
Total	4,528	3,431.8	3,095	2,551.2	1,212	752.3	998	814.8

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2022.

	Undeveloped Acres	
	Gross	Net
Alberta	722,887	605,476
Saskatchewan	249,282	211,447
Total	972,169	816,923

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2022. 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, 2022 to be approximately $166 million, as compared to $89 million as at December 31, 2021. This internal evaluation generally represents the estimated replacement cost of our undeveloped land and excludes approximately 48,261 net acres of our undeveloped land that we expect to expire on or before December 31, 2023. 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

Baytex does not expect to pay any material cash income taxes prior to 2025 as forecasted using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited as of January 1, 2023 used to prepare the Reserves Report. This estimate and any amount of income tax we may be required to pay in the future is highly sensitive to assumptions regarding commodity prices, production, cash flow, capital expenditure levels and changes in governing tax laws. For additional information, see Note 14 of our audited consolidated financial statements for the year ended December 31, 2022 and the information under the heading "*Income Taxes*" in our MD&A for the year ended December 31, 2022.

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, 2022.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	256	207.1	256	207.1
Natural Gas	—	—	12	4.1	12	4.1
Stratigraphic	—	—	—	—	—	—
Service	—	—	1	1.0	1	1.0
Dry	—	—	—	—	—	—
Total	—	—	269	212.2	269	212.2

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ending December 31, 2023, 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	26,370	1,995	14,660	1,276	1,824	3,042	39,813	53,268
Total Proved plus Probable	30,917	2,214	15,906	1,359	1,945	3,168	43,180	60,066
UNITED STATES								
Total Proved	—	—	—	10,663	10,880	32,007	—	26,878
Total Proved plus Probable	—	—	—	11,069	11,389	33,620	—	28,061
TOTAL								
Total Proved	26,370	1,995	14,660	11,940	12,704	35,049	39,813	80,146
Total Proved plus Probable	30,917	2,214	15,906	12,428	13,334	36,787	43,180	88,127

Note:

(1) Includes condensate.

The two properties that account for 20% or more of the estimated 2023 production volumes are the Eagle Ford and the Viking properties. Estimated 2023 production volumes for the Eagle Ford property is 26,878 boe/d on a total proved basis and 28,061 boe/d on a total proved plus probable basis. Estimated 2023 production volumes for the Viking property is 15,915 boe/d on a total proved basis and 17,306 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, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2022
Average Sales Volume [1]					
CANADA					
Light and Medium Crude Oil (bbl/d)	13,047	14,431	14,667	16,316	14,606
Heavy Crude Oil (bbl/d)	31,086	27,475	26,825	23,445	27,230
Bitumen (bbl/d)	1,733	1,769	1,761	1,791	1,763
Tight Oil (bbl/d)	1,286	1,891	799	986	1,244
NGL (bbl/d) [2]	2,136	2,060	2,027	2,206	2,106
Total liquids (bbl/d)	49,288	47,626	46,079	44,744	46,949
Shale Gas (Mcf/d)	3,575	3,305	2,007	2,343	2,812
Natural Gas (Mcf/d)	42,378	45,755	51,029	49,500	47,142
Total (boe/d)	56,946	55,803	54,919	53,385	55,275
UNITED STATES					
Tight Oil (bbl/d)	14,901	13,655	14,154	13,191	13,979
NGL (bbl/d) [2]	8,396	8,746	8,828	9,002	8,741
Total liquids (bbl/d)	23,297	22,401	22,982	22,193	22,720
Shale Gas (Mcf/d)	39,726	29,943	31,133	31,731	33,146
Total (boe/d)	29,918	27,391	28,170	27,482	28,245
TOTAL					
Light and Medium Crude Oil (bbl/d)	13,047	14,431	14,667	16,316	14,606
Heavy Crude Oil (bbl/d)	31,086	27,475	26,825	23,445	27,230
Bitumen (bbl/d)	1,733	1,769	1,761	1,791	1,763
Tight Oil (bbl/d)	16,187	15,546	14,953	14,177	15,223
NGL (bbl/d) [2]	10,532	10,806	10,855	11,208	10,847
Total liquids (bbl/d)	72,585	70,027	69,061	66,937	69,669
Shale Gas (Mcf/d)	43,301	33,248	33,140	34,074	35,958
Natural Gas (Mcf/d)	42,378	45,755	51,029	49,500	47,142
Total (boe/d)	86,864	83,194	83,090	80,867	83,519

	Three Months Ended				Year Ended
	Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2022
CANADA					
Average Net Production Prices [3][8]					
Light and Medium Crude Oil ($/bbl)	108.10	115.48	135.27	113.87	118.33
Heavy Crude Oil ($/bbl)	63.73	84.23	110.95	89.06	85.92
Bitumen ($/bbl)	69.82	86.69	114.55	93.58	91.17
Tight Oil ($/bbl)	110.19	116.72	136.22	114.30	117.67
NGL ($/bbl) [2]	44.83	51.45	58.68	51.78	51.58
Shale Gas ($/Mcf)	4.79	4.49	6.72	4.50	4.99
Natural Gas ($/Mcf)	5.44	4.99	7.02	4.64	5.55
Total ($/boe)	70.20	84.30	104.91	85.81	86.10
Royalties					
Light and Medium Crude Oil and NGL ($/bbl) [2][4]	10.10	10.34	11.81	9.19	10.34
Heavy Crude Oil ($/bbl)	11.51	20.04	25.86	17.56	18.49
Bitumen ($/bbl)	10.41	26.55	36.71	15.01	22.19
Tight Oil ($/bbl)	18.01	14.59	13.86	14.32	15.32
Shale Gas ($/Mcf)	0.43	0.47	1.05	0.17	0.50
Natural Gas ($/Mcf)	0.45	0.61	0.64	0.35	0.52
Total ($/boe) [9]	10.06	14.78	18.24	12.00	13.75
Operating Expenses [5]					
Light and Medium Crude Oil and NGL ($/bbl) [2][4]	15.92	14.89	15.69	13.89	15.06
Heavy Crude Oil ($/bbl)	15.72	17.24	17.44	18.80	17.19
Bitumen ($/bbl)	32.32	24.54	26.02	25.25	27.01
Tight Oil ($/bbl)	9.32	10.22	7.45	9.40	9.32
Shale Gas ($/Mcf)	1.55	1.70	1.24	1.57	1.55
Natural Gas ($/Mcf)	2.51	2.54	2.41	2.34	2.44
Total ($/boe) [9]	15.98	16.19	16.50	16.35	16.25
Transportation Expenses					
Light and Medium Crude Oil and NGL ($/bbl) [2][4]	0.61	0.64	0.77	0.60	0.66
Heavy Crude Oil ($/bbl)	4.24	3.92	3.53	3.23	3.77
Bitumen ($/bbl)	5.24	5.37	5.88	2.88	4.84
Tight Oil ($/bbl)	0.29	0.48	0.36	0.35	0.38
Shale Gas ($/Mcf)	0.05	0.08	0.06	0.06	0.06
Natural Gas ($/Mcf)	0.24	0.22	0.21	0.20	0.22
Total ($/boe) [9]	2.83	2.49	2.35	1.92	2.41
Netback Received [3][6][8]					
Light and Medium Crude Oil and NGL ($/bbl) [2][4]	72.57	81.61	97.69	82.80	83.85
Heavy Crude Oil ($/bbl)	32.26	43.03	64.12	49.47	46.47
Bitumen ($/bbl)	21.85	30.23	45.94	50.44	37.13
Tight Oil ($/bbl)	82.57	91.43	114.55	90.23	92.65
Shale Gas ($/Mcf)	2.76	2.24	4.37	2.70	2.88
Natural Gas ($/Mcf)	2.24	1.62	3.76	1.75	2.37
Total ($/boe)	41.33	50.84	67.82	55.54	53.69

	Three Months Ended				Year Ended
	Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2022
UNITED STATES					
Average Net Production Prices [3][8]					
Tight Oil ($/bbl)	116.20	123.54	141.60	122.31	125.84
NGL ($/bbl) [2]	60.07	69.54	81.06	71.11	70.55
Shale Gas ($/Mcf)	6.93	9.88	8.99	6.06	7.88
Total ($/boe)	83.94	94.59	106.48	89.00	93.36
Royalties					
Tight Oil ($/bbl)	35.65	38.11	43.28	37.63	38.64
NGL ($/bbl) [2]	16.51	19.02	21.78	19.05	19.11
Shale Gas ($/Mcf)	2.01	2.87	2.54	1.73	2.26
Total ($/boe) [9]	25.06	28.21	31.37	26.30	27.70
Operating Expenses [5][7]					
Tight Oil ($/bbl)	7.48	10.71	9.73	8.99	9.19
NGL ($/bbl) [2]	7.48	10.71	9.73	8.99	9.19
Shale Gas ($/Mcf)	1.25	1.79	1.62	1.50	1.53
Total ($/boe) [9]	7.48	10.71	9.73	8.99	9.19
Netback Received [3][6][8]					
Tight Oil ($/bbl)	73.07	74.72	88.59	75.69	78.01
NGL ($/bbl) [2]	36.08	39.81	49.55	43.07	42.25
Shale Gas ($/Mcf)	3.67	5.22	4.83	2.83	4.09
Total ($/boe)	51.40	55.67	65.38	53.71	56.47

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 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, 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 quarterly and annual 2022 MD&As for information related to this measure, which section has been incorporated by reference herein. The quarterly and annual 2022 MD&As are available on SEDAR at www.sedar.com.

(9) Supplementary financial measure. See "Royalties", "Operating Expense", and "Transportation Expense" in the quarterly and annual 2022 MD&As for information related to this measure, which sections have been incorporated by reference herein. The quarterly and annual 2022 MD&As are available on SEDAR at www.sedar.com.

Marketing Arrangements and Forward Contracts

In Canada, we market our oil and natural gas production with attention to maximizing value and counterparty performance. We have a portfolio of sales contracts with a variety of pricing mechanisms, term commitments and customers. For our heavy crude oil volumes, this includes rail commitments. In the United States, production from our assets 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 23, 2023, see Note 17 to our audited consolidated financial statements for the year ended December 31, 2022. 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, 2022. The effective date of the Baytex Reserves Report is December 31, 2022 and the preparation date of the statement is February 2, 2023. 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, 2023.

Disclosure of Reserves Data

The following tables are a combined summary as at December 31, 2022 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*", "- *Reserves and Reserve Categories*" and "- *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, 2022
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	TIGHT OIL		LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED:						
Developed Producing	1,618	1,381	16,144	15,049	29,187	24,694
Developed Non-Producing	—	—	993	883	1,624	1,444
Undeveloped	5,387	4,605	24,814	23,098	20,247	17,584
TOTAL PROVED	7,005	5,986	41,951	39,030	51,058	43,722
PROBABLE	6,717	5,504	21,881	19,989	34,526	28,960
TOTAL PROVED PLUS PROBABLE	13,722	11,490	63,832	59,018	85,584	72,681

CANADA

RESERVES CATEGORY	BITUMEN		SHALE GAS		CONVENTIONAL NATURAL GAS [1]	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
PROVED:						
Developed Producing	939	879	4,764	4,269	59,803	53,606
Developed Non-Producing	—	—	—	—	1,239	1,105
Undeveloped	3,668	3,354	14,431	12,909	25,831	22,315
TOTAL PROVED	4,608	4,233	19,195	17,177	86,872	77,026
PROBABLE	45,751	37,202	18,798	16,412	45,786	40,387
TOTAL PROVED PLUS PROBABLE	50,359	41,436	37,993	33,589	132,658	117,413

CANADA

RESERVES CATEGORY	NATURAL GAS LIQUIDS [2]		TOTAL RESERVES	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	2,835	2,346	61,485	53,995
Developed Non-Producing	25	20	2,849	2,532
Undeveloped	4,792	4,137	65,619	58,648
TOTAL PROVED	7,653	6,503	129,952	115,174
PROBABLE	6,340	5,309	125,979	106,431
TOTAL PROVED PLUS PROBABLE	13,993	11,813	255,931	221,605

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	24,295	17,869	76,164	56,199	25,961	19,155
Developed Non-Producing	1,894	1,395	4,686	3,453	1,708	1,258
Undeveloped	15,370	11,240	102,923	75,628	34,443	25,316
TOTAL PROVED	41,558	30,504	183,773	135,279	62,112	45,730
PROBABLE	14,003	10,285	65,834	48,466	22,388	16,486
TOTAL PROVED PLUS PROBABLE	55,561	40,788	249,607	183,745	84,500	62,216

UNITED STATES

RESERVES CATEGORY	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:		
Developed Producing	62,949	46,391
Developed Non-Producing	4,383	3,229
Undeveloped	66,967	49,161
TOTAL PROVED	134,299	98,780
PROBABLE	47,363	34,848
TOTAL PROVED PLUS PROBABLE	181,662	133,629

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	25,913	19,250	16,144	15,049	29,187	24,694
Developed Non-Producing	1,894	1,395	993	883	1,624	1,444
Undeveloped	20,757	15,844	24,814	23,098	20,247	17,584
TOTAL PROVED	48,563	36,490	41,951	39,030	51,058	43,722
PROBABLE	20,719	15,789	21,881	19,989	34,526	28,960
TOTAL PROVED PLUS PROBABLE	69,283	52,278	63,832	59,018	85,584	72,681

TOTAL

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	939	879	80,928	60,467	59,803	53,606
Developed Non-Producing	—	—	4,686	3,453	1,239	1,105
Undeveloped	3,668	3,354	117,354	88,536	25,831	22,315
TOTAL PROVED	4,608	4,233	202,967	152,456	86,872	77,026
PROBABLE	45,751	37,202	84,633	64,878	45,786	40,387
TOTAL PROVED PLUS PROBABLE	50,359	41,436	287,600	217,335	132,658	117,413

TOTAL

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	28,796	21,502	124,434	100,386
Developed Non-Producing	1,734	1,279	7,231	5,761
Undeveloped	39,235	29,453	132,586	107,808
TOTAL PROVED	69,765	52,234	264,251	213,955
PROBABLE	28,728	21,795	173,342	141,279
TOTAL PROVED PLUS PROBABLE	98,493	74,029	437,593	355,234

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, 2022
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	634,306	944,257	997,752	979,726	941,425	18.48
Developed Non-Producing	111,590	91,931	78,263	68,273	60,665	30.91
Undeveloped	1,471,179	1,063,842	784,543	588,528	447,347	13.38
TOTAL PROVED	2,217,075	2,100,030	1,860,558	1,636,527	1,449,437	16.15
PROBABLE	3,776,874	2,263,876	1,515,320	1,094,802	835,516	14.24
TOTAL PROVED PLUS PROBABLE	5,993,949	4,363,906	3,375,878	2,731,329	2,284,953	15.23

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	2,186,968	1,540,642	1,199,091	998,657	867,099	25.85
Developed Non-Producing	183,923	132,795	106,730	90,843	79,979	33.05
Undeveloped	1,536,181	991,536	700,471	519,507	397,022	14.25
TOTAL PROVED	3,907,072	2,664,973	2,006,292	1,609,007	1,344,100	20.31
PROBABLE	1,526,061	801,113	495,769	339,528	248,975	14.23
TOTAL PROVED PLUS PROBABLE	5,433,133	3,466,086	2,502,061	1,948,535	1,593,075	18.72

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	2,821,274	2,484,899	2,196,843	1,978,383	1,808,524	21.88
Developed Non-Producing	295,513	224,726	184,993	159,116	140,644	32.11
Undeveloped	3,007,360	2,055,378	1,485,014	1,108,035	844,369	13.77
TOTAL PROVED	6,124,148	4,765,002	3,866,851	3,245,534	2,793,537	18.07
PROBABLE	5,302,935	3,064,989	2,011,088	1,434,330	1,084,491	14.23
TOTAL PROVED PLUS PROBABLE	11,427,083	7,829,992	5,877,939	4,679,864	3,878,028	16.55

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2022
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	634,306	944,257	997,752	979,726	941,425
Developed Non-Producing	111,590	91,931	78,263	68,273	60,665
Undeveloped	1,204,039	848,722	608,442	442,308	324,427
TOTAL PROVED	1,949,935	1,884,910	1,684,457	1,490,307	1,326,518
PROBABLE	3,014,978	1,747,788	1,140,095	808,205	608,490
TOTAL PROVED PLUS PROBABLE	4,964,913	3,632,698	2,824,552	2,298,512	1,935,008

UNITED STATES	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,920,632	1,402,590	1,115,994	943,398	827,560
Developed Non-Producing	144,616	106,735	87,964	76,734	69,115
Undeveloped	1,203,081	773,229	542,876	399,746	303,019
TOTAL PROVED	3,268,329	2,282,554	1,746,835	1,419,878	1,199,694
PROBABLE	1,194,889	625,672	386,345	264,372	193,946
TOTAL PROVED PLUS PROBABLE	4,463,218	2,908,226	2,133,179	1,684,250	1,393,640

TOTAL	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	2,554,938	2,346,847	2,113,747	1,923,124	1,768,985
Developed Non-Producing	256,206	198,666	166,227	145,006	129,781
Undeveloped	2,407,120	1,621,951	1,151,318	842,054	627,446
TOTAL PROVED	5,218,263	4,167,464	3,431,292	2,910,185	2,526,212
PROBABLE	4,209,867	2,373,460	1,526,440	1,072,577	802,436
TOTAL PROVED PLUS PROBABLE	9,428,131	6,540,924	4,957,732	3,982,761	3,328,649

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, 2022
FORECAST PRICES AND COSTS

($000s)	REVENUE	ROYALTIES	OPERAT-ING COSTS	DEVELOP-MENT COSTS	WELL ABANDON-MENT COSTS[1]	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
TOTAL PROVED RESERVES								
Canada	9,143,205	1,095,115	3,070,094	1,746,198	1,014,722	2,217,075	267,141	1,949,935
United States	11,058,339	3,444,568	2,623,675	949,215	133,810	3,907,072	638,744	3,268,329
Total	20,201,544	4,539,683	5,693,768	2,695,414	1,148,532	6,124,148	905,884	5,218,263
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	19,192,161	2,728,115	6,436,170	2,958,496	1,075,430	5,993,949	1,029,036	4,964,913
United States	15,440,365	4,810,891	3,720,107	1,329,396	146,837	5,433,133	969,916	4,463,218
Total	34,632,526	7,539,007	10,156,277	4,287,893	1,222,267	11,427,083	1,998,952	9,428,131

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, 2022
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)	888,020	22.78
	Heavy Crude Oil (including solution gas and associated byproducts)	686,131	15.69
	Bitumen (including solution gas and associated byproducts)	59,975	14.17
	Tight Oil (including solution gas and associated byproducts)	1,361,562	37.31
	Natural Gas (associated and non-associated) (including associated byproducts)	31,536	0.99
	Shale Gas (including associated byproducts)	839,627	8.73
	Total	3,866,851	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated byproducts)	1,467,893	24.89
	Heavy Crude Oil (including solution gas and associated byproducts)	1,224,790	16.85
	Bitumen (including solution gas and associated byproducts)	304,750	7.35
	Tight Oil (including solution gas and associated byproducts)	1,750,618	33.49
	Natural Gas (associated and non-associated) (including associated byproducts)	54,333	1.26
	Shale Gas (including associated byproducts)	1,075,555	8.24
	Total	5,877,939	

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, 2022 (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							
2018	64.95	69.65	49.95	3.05	1.55	2.3	0.770
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	94.65	120.55	98.85	6.40	5.55	6.9	0.770
Forecast (9)							
2023	80.33	103.76	76.54	4.74	4.23	—	0.745
2024	78.50	97.74	77.75	4.50	4.40	2.3	0.765
2025	76.95	95.27	77.55	4.31	4.21	2.0	0.768
2026	77.61	95.58	80.07	4.40	4.27	2.0	0.772
2027	79.16	97.07	81.89	4.49	4.34	2.0	0.775
2028	80.74	99.01	84.02	4.58	4.43	2.0	0.775
2029	82.36	100.99	85.73	4.67	4.51	2.0	0.775
2030	84.00	103.01	87.44	4.76	4.60	2.0	0.775
2031	85.69	105.07	89.20	4.86	4.69	2.0	0.775
2032	87.40	106.69	91.11	4.95	4.79	2.0	0.775

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 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 2032 prices and costs escalate at 2.0% annually and the exchange rate remains 0.775.

Weighted average prices realized by us for the year ended December 31, 2022, excluding hedging activities, were $85.92/bbl for heavy crude oil, $91.17/bbl for bitumen, $118.33/bbl for light and medium crude oil, $117.67/bbl for tight oil, $51.58/bbl for NGL, $4.99/Mcf for shale gas and $5.55/Mcf for 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, 2021	46,003	29,705	75,709	4,838	45,874	50,713
Extensions	11,275	3,744	15,019	—	—	—
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	3,034	(866)	2,168	344	(136)	208
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(1)	—	(1)	—	—	—
Economic Factors	686	1,942	2,628	69	12	81
Production	(9,939)	—	(9,939)	(644)	—	(644)
December 31, 2022	51,058	34,526	85,584	4,608	45,751	50,359

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, 2021	46,009	23,296	69,305	5,832	5,189	11,021
Extensions	2,456	636	3,093	1,286	1,187	2,473
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(2,504)	(2,414)	(4,917)	273	304	577
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	1,320	363	1,683	69	37	106
Production	(5,331)	—	(5,331)	(454)	—	(454)
December 31, 2022	41,951	21,881	63,832	7,005	6,717	13,722

DA	NATURAL GAS LIQUIDS [2]			SHALE GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
ber 31, 2021	6,101	4,803	10,904	14,147	11,778	25,925
nsions	1,560	963	2,523	3,205	2,763	5,968
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions [1]	1,365	1,166	2,531	2,679	4,154	6,833
overies	—	—	—	—	—	—
isitions	—	—	—	—	—	—
ositions	(743)	(655)	(1,397)	—	—	—
omic Factors	139	63	202	190	104	294
uction	(769)	—	(769)	(1,026)	—	(1,026)
ber 31, 2022	7,653	6,340	13,993	19,195	18,798	37,993

DA	CONVENTIONAL NATURAL GAS [3]			OIL EQUIVALENT		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
ber 31, 2021	104,423	62,394	166,817	128,546	121,229	249,775
nsions	15,912	4,183	20,095	19,763	7,688	27,451
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions	4,658	(1,880)	2,778	3,735	(1,566)	2,169
overies	—	—	—	—	—	—
isitions	—	—	—	—	—	—
ositions	(24,363)	(21,175)	(45,537)	(4,805)	(4,184)	(8,989)
omic Factors	3,450	2,263	5,713	2,889	2,812	5,701
uction	(17,207)	—	(17,207)	(20,175)	—	(20,175)
ber 31, 2022	86,872	45,786	132,658	129,952	125,979	255,931

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, 2021	47,384	16,296	63,680	66,036	22,948	88,983
Extensions	387	(283)	105	387	(361)	26
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(1,437)	(2,099)	(3,536)	(1,516)	(323)	(1,839)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	327	89	415	397	123	520
Production	(5,102)	—	(5,102)	(3,191)	—	(3,191)
December 31, 2022	41,558	14,003	55,561	62,112	22,388	84,500

D *STATES*	SHALE GAS			OIL EQUIVALENT		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
ber 31, 2021	217,292	73,151	290,443	149,635	51,436	201,070
nsions	996	(879)	117	940	(790)	150
Drilling	—	—	—	—	—	—
oved Recovery	—	—	—	—	—	—
nical Revisions [1]	(23,525)	(6,801)	(30,326)	(6,874)	(3,555)	(10,430)
overies	—	—	—	—	—	—
isitions	—	—	—	—	—	—
ositions	—	—	—	—	—	—
omic Factors	1,108	364	1,472	908	272	1,181
uction	(12,098)	—	(12,098)	(10,309)	—	(10,309)
ber 31, 2022	183,773	65,834	249,607	134,299	47,363	181,662

TOTAL	HEAVY CRUDE OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2021	46,003	29,705	75,709	4,838	45,874	50,713
Extensions	11,275	3,744	15,019	—	—	—
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	3,034	(866)	2,168	344	(136)	208
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(1)	—	(1)	—	—	—
Economic Factors	686	1,942	2,628	69	12	81
Production	(9,939)	—	(9,939)	(644)	—	(644)
December 31, 2022	51,058	34,526	85,584	4,608	45,751	50,359

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, 2021	46,009	23,296	69,305	53,216	21,485	74,701
Extensions	2,456	636	3,093	1,673	904	2,577
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(2,504)	(2,414)	(4,917)	(1,164)	(1,796)	(2,960)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	1,320	363	1,683	395	126	521
Production	(5,331)	—	(5,331)	(5,556)	—	(5,556)
December 31, 2022	41,951	21,881	63,832	48,563	20,719	69,283

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, 2021	72,137	27,751	99,888	231,439	84,928	316,367
Extensions	1,946	602	2,549	4,201	1,883	6,085
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(152)	844	692	(20,846)	(2,647)	(23,492)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(743)	(655)	(1,397)	—	—	—
Economic Factors	536	186	722	1,298	468	1,765
Production	(3,960)	—	(3,960)	(13,125)	—	(13,125)
December 31, 2022	69,765	28,728	98,493	202,967	84,633	287,600

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, 2021	104,423	62,394	166,817	278,181	172,665	450,846
Extensions	15,912	4,183	20,095	20,702	6,898	27,601
Infill Drilling	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	4,658	(1,880)	2,778	(3,140)	(5,121)	(8,261)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(24,363)	(21,175)	(45,537)	(4,804)	(4,184)	(8,989)
Economic Factors	3,450	2,263	5,713	3,797	3,084	6,881
Production	(17,207)	—	(17,207)	(30,485)	—	(30,485)
December 31, 2022	86,872	45,786	132,658	264,251	173,342	437,593

Notes:

(1) Negative technical revisions in light and medium oil are predominantly associated with higher field operating costs in our Viking asset due to inflationary impacts truncating end of life forecasts and natural variation in actual performance vs forecast. Negative technical revisions in tight oil are predominantly associated with higher field operating costs in our Eagle Ford asset due to inflationary impacts truncating end of life forecasts and natural variation in actual performance vs forecast. Negative technical revisions in shale gas are predominantly associated with natural variation in actual performance vs forecast in our Eagle Ford asset.

(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.

Year	Light and Medium Crude Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Crude Oil Gross (Mbbl)		Bitumen Gross (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2020	2,039	31,601	1,152	29,805	82	13,499	3,027	4,434
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

Year	Conventional Natural Gas Gross (MMcf)		Shale Gas Gross (MMcf)		Natural Gas Liquids Gross (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2020	12,306	29,438	2,676	128,541	1,140	40,167
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

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.

Year	Light and Medium Crude Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Crude Oil Gross (Mbbl)		Bitumen Gross (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2020	(2,038)	19,315	1,174	19,619	226	22,844	696	45,588
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

Year	Conventional Natural Gas Gross (MMcf)		Shale Gas Gross (MMcf)		Natural Gas Liquids Gross (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2020	(11,386)	70,042	5,499	76,050	1,006	25,715
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

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 $1,042 million undiscounted ($251 million discounted at 10 percent). This is comprised of $429 million undiscounted ($63 million discounted at 10 percent) associated with active properties, $344 million undiscounted ($157 million discounted at 10 percent) associated with inactive properties, and $268 million undiscounted ($32 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, 2022
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
2023	331,902	357,810	158,081	158,081	489,983	515,891
2024	399,451	440,466	202,135	202,135	601,586	642,601
2025	318,715	434,036	191,174	191,174	509,890	625,211
2026	316,499	518,957	188,121	188,121	504,620	707,078
2027	284,629	359,386	209,704	209,704	494,333	569,090
Remaining	95,002	847,841	—	380,181	95,002	1,228,022
Total (undiscounted)	1,746,198	2,958,496	949,215	1,329,396	2,695,413	4,287,892

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

Volatility of oil and natural gas prices and price differentials

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 arising from Russia's invasion of Ukraine, the impact of pandemics/epidemics (including Covid-19), government regulation, political stability in the Middle East and elsewhere, 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. 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.

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.

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, it is highly likely that 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 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 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 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.

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 could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include 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.

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 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.

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. 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.

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.

We are not the operator of our drilling locations in our Eagle Ford acreage 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 our Eagle Ford acreage 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.

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. Any such reassessment may have an impact on current and future taxes payable. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries. For further details, see *"Legal Proceedings and Regulatory Actions"*.

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.

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.

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.

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 our operations are subject to environmental and health and safety regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations (collectively, "**environmental regulations**") governing occupational health and safety, the spill, release or emission of substances into the environment or otherwise relating to environmental protection. Environmental regulations require that wells, facility sites and other properties associated with our operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. The jurisdictions where we operate have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. Changes to the requirements of liability management programs may result in significant increases to the security that must be posted, the timing of our abandonment and reclamation operations and the costs associated with such operations.

Compliance with environmental regulations can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties. Failure to comply with environmental regulations may result in the imposition of administrative, civil and criminal penalties or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties regardless of negligence or fault. Although it is not expected that the costs of complying with environmental regulations will have a material adverse effect on our financial condition or results of operations, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect. The implementation of new environmental regulations or the modification of existing environmental regulations could reduce demand for crude oil and natural gas, result in stricter standards and enforcement, larger penalties and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition, results of operations or prospects. See "*Industry Conditions*".

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.

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.

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.

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 rise from recent historical lows. 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, 2022 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.

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: 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. The Corporation competes 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 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

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

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.

Indigenous Claims

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

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.

The future acquisition by the Corporation of Common Shares is uncertain

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 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 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.

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, 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 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 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 Ac, 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.

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. The Government of Canada has identified capping and cutting oil and gas sector emissions as a priority to achieving its climate commitments. A discussion document was released in 2022 outlining possible options including the development of a new cap-and-trade system under the Canadian Environmental Protection Act or the modification of existing carbon pollution pricing systems under the Greenhouse Gas Pollution Pricing 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. A supplemental proposal to reduce pollution from the oil and gas sector was released in November 2022.

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 fuel tax. 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 $50 per tCO_2e in 2022 and escalates $15 per tCO_2e annually to $170 per tCO_2e 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 tCO_2e. 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 and as a result our operated facilities are not subject to the federal carbon pollution pricing system. This provincial program requires a 5% reduction for 2022 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 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 tCO_2e. 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% 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.

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 November 2022, a proposed federal regulatory framework for the oil and gas sector was released to achieve the 2030 target.

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 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 and 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

We do not currently pay a dividend and have not paid a dividend in any of the last three years. Any dividends declared in the future will be subject to review by the Board of Directors taking into account our prevailing financial circumstances at the relevant time and any amount distributed in the future will depend on numerous factors, including profitability, fluctuations in working capital, the timing and amount of capital expenditures, applicable law and other factors that the Board may deem relevant. In addition, we may be restricted from paying dividends by the provisions of the agreements governing our current indebtedness and any indebtedness we may incur in the future.

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.sedar.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, 2022 US$410 million principal amount of the 2027 Notes remain outstanding.

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

Credit Facilities

Our Credit Facilities consist of US$850 million of revolving credit facilities comprised of: (i) a US$50 million operating loan and a US$600 million syndicated revolving loan for Baytex, and (ii) a US$10 million operating loan and a US$190 million syndicated revolving loan for Baytex USA. The Credit Facilities are secured and have an extendible four-year term that, 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 our MD&A for the year ended December 31, 2022. Also see *"Material Contracts"*.

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+	B1	B+
Senior Unsecured Debt (Senior Notes)	BB-	B3	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 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 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		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High ($)	Low ($)	Volume Traded
2022						
January	4.72	3.99	132,753,673	4.74	3.99	241,429,762
February	5.79	4.77	140,329,527	5.79	4.77	244,355,422
March	6.35	5.39	185,438,457	6.35	5.39	327,599,132
April	7.11	5.28	139,451,834	7.11	5.28	246,791,354
May	7.16	5.92	130,049,077	7.16	5.92	253,977,599
June	9.00	5.55	204,988,785	9.00	5.55	411,032,452
July	6.88	5.58	116,008,298	6.88	5.58	231,386,060
August	7.22	5.62	124,514,333	7.22	5.62	238,583,199
September	6.79	5.37	123,905,195	6.79	5.37	204,788,690
October	7.40	6.31	91,854,938	7.40	6.32	158,329,864
November	7.75	6.74	88,829,047	7.75	6.74	161,666,153
December	6.76	5.59	66,957,854	6.76	5.59	124,988,738

DIRECTORS AND OFFICERS

Directors of the Corporation

The following table sets forth the name, municipality of residence, age as at December 31, 2022, 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	63	November 2017	Independent businessman.
Trudy M. Curran [2][4] Calgary, Alberta	60	July 2016	Independent businesswoman. Interim Chief Executive Officer and managing director of Riversdale Resources from February 2019 to June 2019.
Eric T. Greager Denver, Colorado	53	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. Prior thereto Vice President and General Manager at Encana Oil & Gas from October 2015 to April 2018.
Don G. Hrap [3][5] Houston, Texas	63	March 2020	Independent businessman. Formerly served in senior leadership roles with ConocoPhillips from 2009-2018, most recently as President, Lower 48 and, prior to that, President Lower 48 and Latin America and Senior Vice President of Western Canada Gas.
Angela Lekatsas Calgary, Alberta	61	February 2023	Independent businesswoman. Formerly served as 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	52	September 2019	Independent businesswoman. Formerly Chief Executive Officer of Vale Canada and Executive Director of Vale-SA-Base Metals from November 2014 until December 2017.
Greg Melchin [4][5] Calgary, Alberta	69	May 2008	Independent businessman.
David L. Pearce [2][3] Calgary, Alberta	68	August 2018	Deputy Managing Partner, Azimuth Capital Management.
Stephen D.L. Reynish [3][4] Calgary, Alberta	64	November 2020	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.

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, 2022, 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	53	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. Prior thereto Vice President and General Manager at Encana Oil & Gas from October 2015 to April 2018.
Chad L. Kalmakoff Calgary, Alberta	46	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	41	Chief Operating & Sustainability Officer	Chief Operating & Sustainability Officer of the Corporation since July 2021. Prior thereto Vice President, Light Oil since December 2018. Prior thereto Vice President, Viking Business unit of the Corporation since August 2018, Vice President, Operations of Raging River Exploration Inc. from October 2016 until August 2018.
Kendall D. Arthur Calgary, Alberta	42	Vice President, Heavy Oil	Vice President, Heavy Oil of the Corporation since December 2018. Prior thereto, a business unit Vice President with the Corporation since January 2012.
Brian G. Ector Calgary, Alberta	54	Vice President, Capital Markets	Vice President, Capital Markets of the Corporation since August 2018. Prior thereto, an officer of the Corporation since June 2011.
Nicole Frechette Calgary, Alberta	39	Vice President, Light Oil	Vice President, Light Oil of the Corporation 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.
M. Scott Lovett Calgary, Alberta	49	Vice President, Corporate Development	Vice President, Corporate Development of the Corporation since September 2017. Prior thereto, Executive Vice President, Business Development with Eagle Energy Inc. from September 2014 until August 2017.
James Maclean Calgary, Alberta	43	Vice President, General Counsel and Corporate Secretary	Vice President, General Counsel and Corporate Secretary since February 2022. Prior thereto General Counsel and Corporate Secretary since August 2018 and various legal roles with the Corporation since May 2014.

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, 3,467,507 Common Shares.

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 and Gregory K. Melchin, each of whom is independent and financially literate within the meaning of National Instrument 52-110 "*Audit Committees*" and the NYSE listing standards. In addition, the Board has determined that Ms. Maki and Mr. Melchin are "Audit Committee Financial Experts" pursuant to the SEC's definition of the term.

The relevant education and experience of each Audit Committee member is outlined below:

Name	Relevant Education and Experience
Jennifer A. Maki *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	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.
Gregory K. Melchin	Bachelor of Science degree (major in accounting) and a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. Also completed the Directors Education Program with the Institute of Corporate Directors. Member of the Legislative Assembly of Alberta from March 1997 to March 2008. Prior to being elected to the Legislative Assembly of Alberta, served in various management positions for 20 years in the Calgary business community.

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 2022 and 2021:

Year	Audit Fees [1]	Audit-Related Fees [2]	Tax Fees [3]	All Other Fees [4]	Total
2022	$ 1,145	$ —	$ —	$ —	$ 1,145
2021	$ 989	$ —	$ —	$ —	$ 989

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 2022 and 2021 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 Canada Revenue Agency (CRA) that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. We remain confident that the tax filings of the affected entities are correct and are vigorously defending our tax filing positions. The reassessments do not require us to pay any amounts in order to participate in the appeals process.

In September 2016, we filed a notice of objection for each notice of reassessment received which will be reviewed by the Appeals Division of the CRA. An Appeals Officer was assigned to our file in July 2018, we estimate the remaining Appeals Division process could take another year. If the Appeals Division upholds the notices of reassessment, we have the right to appeal to the Tax Court of Canada; a process that we estimate could take a further two years. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another one or two years and potentially longer.

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 used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Tax Act. If, after exhausting available appeals, the deduction of Losses continues to be disallowed, we will owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax

shelter from future years that may be applied to the years 2012 through 2015. The tax shelter available for carryback will diminish as the Corporation reaches it tax horizon.

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

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 2027 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 second amended and restated credit agreement in respect of the Credit Facilities (filed on SEDAR on March 29, 2022);

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

c. 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).

Copies of each of these contracts are accessible on the SEDAR website at *www.sedar.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.sedar.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, 2022 and the related MD&A which are accessible on the SEDAR website at *www.sedar.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 23, 2023

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 Baytex's reserves data as at December 31, 2022. The reserves data is an estimate of proved reserves and probable reserves and related future net revenue as at December 31, 2022 estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the 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, 2022, and identifies the respective portions thereof that we have evaluated and reported on to Company's management:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation or Review 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, 2022	Canada	—	3,375,878	—	3,375,878
McDaniel & Associates	December 31, 2022	United States	—	2,502,061	—	2,502,061
TOTALS				5,877,939		5,877,939

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not 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 2, 2023

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

Exhibit 99.2

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our President and Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2022, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2022 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2022.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of the Company. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Public Accounting Firm to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of KPMG LLP and reviews their fees. The Independent Registered Public Accounting Firm has access to the Audit Committee without the presence of management.

/s/ Eric T. Greager

Eric T. Greager
President and Chief Executive Officer
Baytex Energy Corp.

/s/ Chad L. Kalmakoff

Chad L. Kalmakoff
Chief Financial Officer
Baytex Energy Corp.

February 23, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Baytex Energy Corp.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of Baytex Energy Corp. (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of income and comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and its financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2023 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of the recoverable amount of oil and gas properties

As discussed in note 6 to the consolidated financial statements, the Company identified indicators of impairment reversal as of December 31, 2022 related to the Company's Lloydminster, Viking and Eagle Ford cash generating units (CGUs). The Company therefore determined the recoverable amount as of December 31, 2022 of each of the CGUs and recorded an impairment reversal of $81 million in the Viking CGU. The determination of recoverable amount of a CGU involves numerous estimates, including cash flows associated with estimated proved and probable oil and gas reserves of the CGU ("CGU reserves") and the discount rate. The estimation of CGU reserves involves the expertise of independent reserves evaluators, who take into consideration assumptions related to forecasted production volumes, royalty, operating and capital costs and commodity prices (collectively "reserve assumptions"). The Company engages independent reserves evaluators to estimate CGU reserves.

We identified the assessment of the recoverable amount of the Lloydminster, Viking, and Eagle Ford CGUs as a critical audit matter. Minor changes in reserve assumptions and discount rates could have had a significant impact on the estimate of recoverable amounts and the resulting impairment reversal in the carrying amount of oil and gas properties relating to the CGUs. A high degree of auditor judgment was required to evaluate the Company's estimates of CGU reserves, and related reserve assumptions, and the discount rates, which were inputs into the calculation of recoverable amounts. Additionally, the evaluation of these estimates required involvement of valuation professionals with specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to:

- the Company's determination of the recoverable amount of each of the CGUs, including the discount rate
- the Company's determination of reserve assumptions of the CGU reserves and resulting cash flows.

We evaluated the competence, capabilities and objectivity of the independent reserves evaluators engaged by the Company. We evaluated the methodology used by the independent reserves evaluators to estimate the CGU reserves for compliance with regulatory standards. We compared the current year actual CGU production volumes, royalty, operating and capital costs to those estimates used in the prior year estimate of proved reserves by CGU to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of the CGU reserves by comparing them to those published by other reserve engineering companies. We assessed the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the current year estimate of the CGU reserves by comparing them to historical results. We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of discount rates by comparing the inputs of the discount rate against publicly available market data for comparable assets and assessing the resulting discount rate
- evaluating the Company's estimate of recoverable amount of the CGUs by comparing to publicly available market data and valuation metrics for comparable entities.

Impact of estimated oil and gas reserves on depletion expense related to oil and gas properties

As discussed in note 3 to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method by depletable area. Under such method, capitalized costs are depleted over estimated proved and probable oil and gas reserves by depletable area ("area reserves"). As discussed in note 6 to the consolidated financial statements, the Company recorded depletion expense related to oil and gas properties of $581 million for the year ended December 31, 2022. The estimation of area reserves requires the expertise of independent reserves evaluators who take into consideration reserve assumptions. The Company engages independent reserves evaluators to estimate area reserves.

We identified the assessment of the impact of estimated area reserves on depletion expense related to oil and gas properties as a critical audit matter. Changes in assumptions used to estimate area reserves could have had a significant impact on the calculation of depletion expense of the depletable area. A high degree of auditor judgment was required in evaluating the area reserves, and related reserve assumptions, which were used in the calculation of depletion expense.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to:

- the Company's calculation of depletion expense
- the Company's determination of reserve assumptions and resulting area reserves.

We assessed the calculation of depletion expense for compliance with International Financial Reporting Standards as issued by the International Accounting Standards Board. We evaluated the competence, capabilities and objectivity of the independent reserves evaluators engaged by the Company. We evaluated the methodology used by the independent reserves evaluators to estimate area reserves for compliance with regulatory standards. We compared current year actual area production volumes, royalty, operating and capital costs to those estimates used in the prior year estimate of proved reserves by area to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of area reserves by comparing them to those published by other reserves engineering companies. We assessed the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the estimate of area reserves by comparing them to historical results.

/s/ KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditor since 2016.

Calgary, Canada
February 23, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Baytex Energy Corp.

Opinion on Internal Control Over Financial Reporting

We have audited Baytex Energy Corp.'s (and subsidiaries') (the "Company") internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated statements of financial position of the Company as of December 31, 2022 and 2021, the related consolidated statements of income and comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements), and our report dated February 23, 2023 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 23, 2023

Baytex Energy Corp.
Consolidated Statements of Financial Position

(thousands of Canadian dollars)

As at	Notes	December 31, 2022	December 31, 2021
ASSETS			
Current assets			
Cash		**$ 5,464**	$ —
Trade and other receivables	17	**228,485**	173,409
Financial derivatives	17	**10,105**	8,654
		244,054	182,063
Non-current assets			
Exploration and evaluation assets	5	**168,684**	172,824
Oil and gas properties	6	**4,620,766**	4,464,371
Other plant and equipment		**6,568**	7,121
Lease assets		**6,453**	8,264
Deferred income tax asset	14	**57,244**	—
		$ 5,103,769	$ 4,834,643
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 272,195**	$ 190,692
Financial derivatives	17	**—**	134,020
Lease obligations		**3,521**	2,938
Asset retirement obligations	9	**12,813**	11,080
		288,529	338,730
Non-current liabilities			
Other payables		**9,209**	—
Credit facilities	7	**383,031**	505,171
Long-term notes	8	**547,598**	874,527
Lease obligations		**3,017**	4,827
Asset retirement obligations	9	**576,110**	732,603
Deferred income tax liability	14	**265,858**	167,456
		2,073,352	2,623,314
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	**5,499,664**	5,736,593
Contributed surplus		**89,879**	13,559
Accumulated other comprehensive income		**756,195**	632,103
Deficit		**(3,315,321)**	(4,170,926)
		3,030,417	2,211,329
		$ 5,103,769	$ 4,834,643

Commitments (note 19)

See accompanying notes to the consolidated financial statements.

/s/ Mark R. Bly
Mark R. Bly
Director, Baytex Energy Corp.

/s/ Jennifer A. Maki
Jennifer A. Maki
Director, Baytex Energy Corp.

Baytex Energy Corp.
Consolidated Statements of Income and Comprehensive Income

(thousands of Canadian dollars, except per common share amounts and weighted average common shares)

Years Ended December 31	Notes	2022	2021
Revenue, net of royalties			
Petroleum and natural gas sales	13	**$ 2,889,045**	$ 1,868,195
Royalties		**(562,964)**	(339,156)
		2,326,081	1,529,039
Expenses			
Operating		**422,666**	343,002
Transportation		**48,561**	32,261
Blending and other		**189,454**	85,689
General and administrative		**50,270**	40,804
Exploration and evaluation	5	**30,239**	15,212
Depletion and depreciation		**587,050**	464,580
Impairment reversal	5, 6	**(267,744)**	(1,542,414)
Share-based compensation	11	**29,056**	11,130
Financing and interest	15	**104,817**	111,159
Financial derivatives loss	17	**199,010**	287,872
Foreign exchange loss (gain)	16	**43,441**	(2,868)
Gain on dispositions		**(4,898)**	(9,666)
Other expense (income)		**3,244**	(2,562)
		1,435,166	(165,801)
Net income before income taxes		**890,915**	1,694,840
Income tax expense	14		
Current income tax expense		**3,594**	1,272
Deferred income tax expense		**31,716**	79,968
		35,310	81,240
Net income		**$ 855,605**	$ 1,613,600
Other comprehensive income			
Foreign currency translation adjustment		**124,092**	13,127
Comprehensive income		**$ 979,697**	$ 1,626,727
Net income per common share	12		
Basic		**$ 1.53**	$ 2.86
Diluted		**$ 1.52**	$ 2.82
Weighted average common shares	12		
Basic		**557,986**	563,674
Diluted		**563,835**	571,610

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.
Consolidated Statements of Changes in Equity
(thousands of Canadian dollars)

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	**Total equity**
Balance at December 31, 2020		$ 5,729,418	$ 14,345	$ 618,976	$ (5,784,526)	**$ 578,213**
Vesting of share awards	10	7,175	(7,175)	—	—	**—**
Share-based compensation	11	—	6,389	—	—	**6,389**
Comprehensive income		—	—	13,127	1,613,600	**1,626,727**
Balance at December 31, 2021		$ 5,736,593	$ 13,559	$ 632,103	$ (4,170,926)	**$ 2,211,329**
Vesting of share awards	10	8,501	(8,501)	—	—	**—**
Share-based compensation	11	—	3,159	—	—	**3,159**
Transfers for liability-classified awards	11	—	(4,791)	—	—	**(4,791)**
Repurchase of common shares for cancellation	10	(245,430)	86,453	—	—	**(158,977)**
Comprehensive income		—	—	124,092	855,605	**979,697**
Balance at December 31, 2022		$ 5,499,664	$ 89,879	$ 756,195	$ (3,315,321)	**$ 3,030,417**

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.
Consolidated Statements of Cash Flows
(thousands of Canadian dollars)

Years Ended December 31	Notes	2022	2021
CASH PROVIDED BY (USED IN):			
Operating activities			
Net income		**$ 855,605**	$ 1,613,600
Adjustments for:			
Non-cash share-based compensation	11	**3,159**	6,389
Unrealized foreign exchange loss (gain)	16	**45,073**	(1,905)
Exploration and evaluation	5	**30,239**	15,212
Depletion and depreciation		**587,050**	464,580
Impairment reversal	5, 6	**(267,744)**	(1,542,414)
Non-cash financing and interest	15	**24,431**	19,090
Non-cash other income	9	**(4,009)**	(2,857)
Unrealized financial derivatives (gain) loss	17	**(135,471)**	103,631
Gain on dispositions		**(4,898)**	(9,666)
Deferred income tax expense	14	**31,716**	79,968
Asset retirement obligations settled	9	**(18,351)**	(6,662)
Change in non-cash working capital	18	**26,072**	(26,582)
Cash flows from operating activities		**1,172,872**	712,384
Financing activities			
Decrease in credit facilities	7	**(136,980)**	(145,321)
Debt issuance costs		**(2,138)**	—
Payments on lease obligations		**(3,732)**	(4,334)
Redemption of long-term notes	8	**(376,589)**	(251,969)
Repurchase of common shares	10	**(158,977)**	—
Cash flows used in financing activities		**(678,416)**	(401,624)
Investing activities			
Additions to exploration and evaluation assets	5	**(6,359)**	(3,298)
Additions to oil and gas properties	6	**(515,183)**	(310,005)
Additions to other plant and equipment		**(1,148)**	(907)
Property acquisitions		**(1,352)**	(1,557)
Proceeds from dispositions		**25,649**	7,804
Change in non-cash working capital	18	**9,401**	(2,797)
Cash flows used in investing activities		**(488,992)**	(310,760)
Change in cash		**5,464**	—
Cash, beginning of year		**—**	—
Cash, end of year		**$ 5,464**	$ —
Supplementary information			
Interest paid		**$ 84,225**	$ 93,114
Income taxes paid		**$ 2,303**	$ 253

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is an energy company engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and in Texas, United States. The Company’s common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company’s head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PRESENTATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). The significant accounting policies set forth below were consistently applied to all periods presented.

The consolidated financial statements were approved by the Board of Directors of Baytex on February 23, 2023.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of certain fair value measurements noted in the accounting policies set forth below. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. References to “US$” are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or where otherwise indicated.

Current Environment and Estimation Uncertainty

Management makes judgements and assumptions about the future in deriving estimates used in preparation of these consolidated financial statements in accordance with IFRS. Sources of estimation uncertainty include estimates used to determine economically recoverable oil, natural gas, and natural gas liquids reserves, the recoverable amount of long-lived assets or cash generating units, the fair value of financial derivatives, the provision for asset retirement obligations and the provision for income taxes and the related deferred tax assets and liabilities.

Early in 2022, energy prices strengthened to multi-year highs due to heightened uncertainty of global oil and natural gas supply after Russia's invasion of Ukraine in addition to limited production growth reflecting oil and gas producers' capital discipline. Declines in global oil prices during the second half of 2022 were caused by concern over future demand due to central bank actions to moderate inflation. The impact of these factors has been considered in management's estimates as at and for the period ended December 31, 2022.

Environmental Reporting Regulations

Environmental reporting for public enterprises continues to evolve and the Company may be subject to additional future disclosure requirements. The International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 *Disclosure of Climate-related Matters* which sets forth additional reporting requirements for Canadian Public Companies. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

Measurement Uncertainty and Judgments

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available, including considerations related to environmental regulation and related matters, to the Company at the time of financial statement preparation. Actual results can differ from those estimates as the effect of future events cannot be determined with certainty. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and natural gas liquids ("NGL") reserves in the calculation of depletion, evaluating the recoverability of deferred income tax assets and in the determination of fair value estimates for non-financial assets. The process to estimate reserves is complex and requires significant judgment. Estimates of the Company's reserves are

evaluated annually by independent reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL and the related net cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGL and their future net cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forward price forecasts, production rates, ultimate reserve recovery, timing and amount of capital expenditures, production costs, marketability of oil and natural gas, royalty rates and other geological, economic and technical factors could have a significant impact on reported reserves. Changes in the Company's reserves estimates can have a significant impact on the carrying values of the Company's oil and gas properties, the calculation of depletion, the valuation of deferred income tax assets, the timing of cash flows for asset retirement obligations, asset impairments or reversals and estimates of fair value determined in accounting for business combinations.

Cash-generating Units ("CGUs")

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment and Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. The assessment for each CGU considers significant changes in reservoir performance including forecasted production volumes, forecasted royalty, operating, capital and abandonment and reclamation costs, forecasted oil and gas prices and the resulting cash flows from proved plus probable oil and gas reserves. The assessment for exploration and evaluation ("E&E") assets considers arm's length sale transactions and significant changes in the Company's development plans.

Measurement of Recoverable Amounts

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including cash flows associated with proved plus probable oil and gas reserves, the discount rate used to present value future cash flows, and assumptions regarding the timing and amount of capital expenditures and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

E&E Assets

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. The determination of technical feasibility and commercial viability of E&E assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment. Management uses the establishment of commercial reserves as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets are tested for impairment and reclassified to oil and natural gas properties.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future, and discount and inflation rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. Actual abandonment and reclamation costs could be materially different from estimated amounts.

Income Taxes

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies to obtain benefits from its activities. Significant subsidiaries included in the Company's accounts include Baytex Energy USA, Inc., Baytex Energy Ltd. and Baytex Energy Limited Partnership. Intercompany transactions are eliminated in preparation of the consolidated financial statements.

Many of the Company's exploration, development and production activities are conducted through joint arrangements. The consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues and expenses generated by joint arrangements.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the acquired assets meet the definition of a business under IFRS. The cost of an acquisition is measured as cash paid and the fair value of assets given, equity instruments issued, and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. If the cost of acquisition is below the fair values of the identifiable net assets acquired, the difference is recognized as a bargain purchase gain in net income or loss. Associated transaction costs are expensed when incurred.

Revenue Recognition

Revenue from the sale of light oil and condensate, heavy oil, natural gas liquids, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue by unit of production and when control of the product transfers to the customer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. Baytex recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis when Baytex acts in the capacity of an agent rather than as a principal.

The transaction price for variable price contracts in the Canadian and U.S. operating segments is based on a representative commodity price index, and may include adjustments for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Tariffs, tolls and fees charged to other entities for the use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

E&E Assets

Pre-license costs, including certain geological, geophysical and seismic expenditures, are incurred before the legal rights to explore a specific area have been obtained. These costs are charged to exploration expense in the period in which they are incurred.

Once the legal right to explore has been acquired, costs directly associated with an exploration program are capitalized as an intangible asset until results of the exploration program have been evaluated. Costs capitalized as E&E assets include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing of initial production results.

E&E costs are subject to technical, commercial and management review to confirm the continued intent to develop or otherwise extract the underlying reserves. The technical feasibility and commercial viability of extracting petroleum and natural gas resources is dependent on the existence of economically recoverable reserves for the project. If the asset is determined not to be technically feasible or commercially viable the accumulated E&E costs associated with the exploration project are charged to E&E expense in the period the determination is made.

Upon determination of technical feasibility and commercial viability, as evidenced by the classification of commercial reserves and management's intention to develop the E&E asset, the accumulated costs associated with the exploration project are tested for impairment and transferred to oil and gas properties.

Oil and Gas Properties

Oil and gas properties are initially recorded at cost and include the costs to acquire, develop, complete geological and geophysical surveys, drill wells, and construct and install infrastructure including wellhead equipment and processing facilities.

Oil and gas properties includes costs related to planned major inspection, overhaul and turnaround activities to maintain items of oil and gas properties and benefit future years of operations. Replacements outside of a major inspection, overhaul or turnaround are recognized as oil and gas properties when it is probable the economic benefits of the replacement will be realized by the Company in the future. The carrying amount of any replaced or disposed item of oil and gas properties is derecognized. Repair and maintenance costs incurred for servicing an item of oil and gas properties is recorded as operating expense as incurred.

Depletion

The costs associated with oil and gas properties are depleted on a unit-of-production basis by depletable area over proved plus probable reserves once commercial production has commenced. Future development costs required to bring those reserves into production are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil equivalent.

Impairment and Impairment Reversals

Non-financial Assets

The Company reviews its non-financial assets for indicators of impairment and impairment reversal at the end of each reporting period. E&E assets are also assessed for impairment when they are reclassified to oil and gas properties. The recoverable amount of the asset is estimated if indicators of impairment or impairment reversal exist.

When reviewing for indicators of impairment or impairment reversal, and testing for impairment or impairment reversal when indicators have been identified, assets are grouped together at a CGU level. The recoverable amount of an asset or CGU is the higher of its FVLCD and its VIU. The determination of recoverable amount includes estimates of proved and probable oil and gas reserves and the associated cash flows. Factors that impact these cash flows include CGU production volumes, royalty obligations, operating costs, capital costs, forecasted commodity prices, along with inflation and discount rates used to estimate present value. FVLCD is the amount that would be obtained from the sale of an asset or CGU in an arm's length transaction. In determining FVLCD, recent market transactions are considered if available. In the absence of such transactions, an appropriate valuation model is used. VIU is assessed using the present value of the estimated future cash flows of the asset or CGU. The estimated future cash flows are adjusted for risks specific to the asset or CGU and are discounted using a discount rate that reflects current market assessments of the time value of money.

Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces the carrying amount of any goodwill allocated to the CGU first, with any remaining impairment being allocated to the individual assets in the CGU on a pro-rata basis.

Impairments may be reversed for all CGUs and individual assets, other than goodwill, when there is indication that a previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the asset’s revised carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized. Impairment recognized in relation to goodwill is not reversed for subsequent increases in its recoverable amount.

Impairments and impairment reversals are recorded in net income or loss in the period the impairment or impairment reversal occurs.

Asset Retirement Obligations

The Company recognizes asset retirement obligations when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The Company’s asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future.

Asset retirement obligations are recognized for future asset retirement costs associated with the abandonment and reclamation of the Company's E&E assets and oil and gas properties. Asset retirement obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, discounted using the risk-free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted over its useful life. The asset retirement obligation is accreted until the date of expected settlement of the retirement obligation and is recognized within financing and interest expense in the consolidated statements of income and comprehensive income. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows or the discount rates are recognized as changes in the asset retirement obligation provision and related asset at each reporting date.

Foreign Currency Translation

Foreign Transactions

Transactions completed in currencies other than the functional currency are translated into the functional currency at the exchange rates prevailing at the time of the transactions. Foreign currency assets and liabilities are translated to functional currency at the period-end exchange rate. Revenue and expenses are translated to functional currency using the average exchange rate for the period. Realized and unrealized gains and losses resulting from the settlement or translation of foreign currency transactions are included in net income or loss.

Foreign Operations

The functional currency of the Company's subsidiaries is the currency of the primary economic environment in which the entity operates. Certain subsidiaries of the Company operate and transact primarily in currencies other than the Canadian dollar. Management judgement is required in the designation of a subsidiary's functional currency.

The financial statements of each entity are translated into Canadian dollars during the preparation of the Company's consolidated financial statements. The assets and liabilities of a foreign operation are translated to Canadian dollars at the period-end exchange rate. Revenues and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. Foreign exchange differences are recognized in other comprehensive income or loss.

If the Company or any of its entities disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net income or loss.

Financial Instruments

Financial assets are initially classified into three categories: measured at amortized cost; fair value through other comprehensive income (“FVOCI”); or fair value through profit or loss (“FVTPL”). Financial assets are categorized based on the Company’s objective for the asset and the contractual cash flows. A financial asset is classified as amortized cost if the asset is held with the objective to collect contractual cash flows that are solely payments of principal and interest on principal amounts outstanding. A financial asset is classified as FVOCI if the asset is held with the objective to both collect contractual cash flows and sell the financial asset. All other financial assets are measured at FVTPL. Financial assets are assessed for impairment using an expected credit loss model.

The measurement category for each class of financial asset and financial liability is set forth in the following table.

Financial Instrument	Classification
Cash	Amortized cost
Trade and other receivables	Amortized cost
Financial derivatives	Fair value through profit or loss
Trade and other payables	Amortized cost
Credit facilities	Amortized cost
Long-term notes	Amortized cost

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts consist of a host contract and an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative unless the economic characteristics and risks of the embedded derivative are closely related to the host contract. Embedded derivatives are measured at FVTPL.

Debt issuance costs related to the amendment of the Company's credit facilities or the issuance of long-term notes are capitalized and amortized as financing costs over the term of the credit facilities or long-term notes. For a financial asset or a financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to, or deducted from, the fair value on initial recognition and amortized through net income or loss over the term of the financial instrument. Transaction costs that are directly attributable to the acquisition or issue of a financial asset or a financial liability classified as FVTPL are expensed at inception of the contract.

The Company formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Company are related to underlying financial instruments or future petroleum and natural gas production. These instruments are classified as FVTPL. The Company does not use financial derivatives for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and therefore has not applied hedge accounting. As a result, the Company applies the fair value method of accounting for all derivative instruments by recording an asset or liability on the statements of financial position and recognizing changes in the fair value of the instrument in the consolidated statements of income and comprehensive income for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts. Attributable transaction costs are recognized in net income or loss when incurred.

The Company accounts for its physical delivery sales contracts as executory contracts. These contracts are entered into and held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements. As such, these contracts are not considered to be derivative financial instruments and are not recorded at fair value on the statements of financial position. Settlements on these physical delivery sales contracts are recognized in revenue in the period the product is delivered to the sales point.

Impairment of financial assets is determined by calculating the expected credit loss ("ECL"). The Company measures an ECL allowance for trade and other receivables. The Company determines the ECL, which is the probability of default events related to the financial asset, by using historical realized bad debts and forward-looking information. The carrying amounts of financial assets are reduced by the amount of the ECL through an allowance account and losses are recognized in the statement of income or loss.

Fair Value of Financial Instruments

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the number of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

Income Taxes

Current and deferred income taxes are recognized in net income or loss, except when they relate to items that are recognized directly in equity, in which case the current and deferred taxes are also recognized directly in equity.

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted at the end of the reporting period. The Company recognizes the financial statement impact of a tax filing position when it is probable that the position will be sustained upon audit. The liability is measured based on an assessment of possible outcomes and their associated probabilities.

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all deductible temporary differences to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced or increased to the extent that it is no longer probable or becomes probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Share-based Compensation Plans

Share Award Incentive Plan

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "Share Awards") may be granted to directors, officers and employees of the Company and its subsidiaries. Pursuant to the Share Award Incentive Plan, Baytex has the option to settle amounts payable related to Share Awards in cash on the settlement date. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not exceed 3.8% of the then-issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents), or the equivalent cash value at the time of vesting. Each performance award entitles the holder to be issued the number of common shares designated in the performance award (plus dividend equivalents) multiplied by a performance multiplier, or the equivalent cash value at the time of vesting. The multiplier is dependent on the performance of the Company relative to predefined corporate performance measures for a particular period. The number of common shares to be issued on the applicable issue date for the Share Awards is adjusted to account for the payments of dividends from the grant date to the applicable issue date.

When Share Awards are accounted for as equity-settled, share-based compensation expense is determined using the fair value of the Share Awards on the grant date which is based on quoted market prices for the Company's common shares. Share Awards vest in equal tranches on the first, second and third anniversaries of the grant date and are expensed over the vesting period using the graded vesting method, with a corresponding increase to contributed surplus. On the vest date, the associated contributed surplus is recognized in shareholders' capital.

In December 2022, the Company received approval from its Board of Directors to settle the existing Share Awards with cash under the terms of the Share Award Incentive Plan. As a result, Baytex recognized the fair value of the liability for amortized unvested Share Awards in trade and other payables. The fair value of the liability recognized exceeded the amount previously recognized in contributed surplus of $4.8 million and the excess was recognized as share-based compensation expense in the period.

Incentive Award Plan and Deferred Share Unit Plan

The Company has a cash-settled incentive award plan (the "Incentive Award Plan") pursuant to which incentive awards may be granted to officers and employees of the Company and its subsidiaries. Each incentive award entitles the holder to receive a cash payment equal to the value of one Baytex common share at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date using the graded vesting method.

The Company has a cash-settled deferred share unit plan (the "DSU Plan") pursuant to which deferred share units ("DSUs") may be granted to independent directors of the Company and its subsidiaries. Each DSU entitles the holder to receive a cash payment equal to the value of one Baytex common share on the date at which they cease to be a member of the Board. The awards vest immediately upon being granted and are expensed in full on the grant date.

Liabilities associated with cash-settled awards are determined based on the fair value of the award at grant date and are subsequently revalued at each period end until the date of settlement. This valuation incorporates the period-end share price, the number of awards outstanding at each period end, and certain management estimates, such as estimated forfeitures and performance multiplier, if applicable. Share-based compensation expense related to cash-settled awards is recognized in the consolidated statements of income and comprehensive income over the relevant service period with a corresponding increase or decrease in trade and other payables. Classification of the associated short-term and long-term liabilities is dependent on the expected payout dates of the individual awards.

Normal Course Issuer Bid ("NCIB") Share Repurchases

On May 2, 2022, Baytex announced the acceptance from the Toronto Stock Exchange ("TSX") for implementation of an NCIB under which Baytex is permitted to purchase for cancellation a specified number of common shares over a specified time frame. The shares repurchased and cancelled are accounted for as a reduction in shareholders' capital at historical cost, with any discount paid recorded to contributed surplus and any premium paid recorded to retained earnings. Total consideration paid includes any commissions or fees paid as part of the transaction.

4. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the U.S.; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 1,926,561**	$ 1,128,137	**$ 962,484**	$ 740,058	**$ —**	$ —	**$ 2,889,045**	$ 1,868,195
Royalties	**(277,428)**	(121,306)	**(285,536)**	(217,850)	**—**	—	**(562,964)**	(339,156)
	1,649,133	1,006,831	**676,948**	522,208	**—**	—	**2,326,081**	1,529,039
Expenses								
Operating	**327,894**	257,658	**94,772**	85,344	**—**	—	**422,666**	343,002
Transportation	**48,561**	32,261	**—**	—	**—**	—	**48,561**	32,261
Blending and other	**189,454**	85,689	**—**	—	**—**	—	**189,454**	85,689
General and administrative	**—**	—	**—**	—	**50,270**	40,804	**50,270**	40,804
Exploration and evaluation	**30,239**	15,212	**—**	—	**—**	—	**30,239**	15,212
Depletion and depreciation	**409,286**	303,135	**171,747**	155,806	**6,017**	5,639	**587,050**	464,580
Impairment reversal	**(267,744)**	(1,100,000)	**—**	(442,414)	**—**	—	**(267,744)**	(1,542,414)
Share-based compensation	**—**	—	**—**	—	**29,056**	11,130	**29,056**	11,130
Financing and interest	**—**	—	**—**	—	**104,817**	111,159	**104,817**	111,159
Financial derivatives loss	**—**	—	**—**	—	**199,010**	287,872	**199,010**	287,872
Foreign exchange loss (gain)	**—**	—	**—**	—	**43,441**	(2,868)	**43,441**	(2,868)
(Gain) loss on dispositions	**(4,898)**	(9,856)	**—**	190	**—**	—	**(4,898)**	(9,666)
Other (income) expense	**(4,009)**	(2,857)	**—**	—	**7,253**	295	**3,244**	(2,562)
	728,783	(418,758)	**266,519**	(201,074)	**439,864**	454,031	**1,435,166**	(165,801)
Net income (loss) before income taxes	**920,350**	1,425,589	**410,429**	723,282	**(439,864)**	(454,031)	**890,915**	1,694,840
Income tax expense								
Current income tax expense							**3,594**	1,272
Deferred income tax expense							**31,716**	79,968
							35,310	81,240
Net income (loss)	**$ 920,350**	$ 1,425,589	**$ 410,429**	$ 723,282	**$ (439,864)**	$ (454,031)	**$ 855,605**	$ 1,613,600
Additions to exploration and evaluation assets	**6,359**	3,298	**—**	—	**—**	—	**6,359**	3,298
Additions to oil and gas properties	**374,443**	204,912	**140,740**	105,093	**—**	—	**515,183**	310,005
Property acquisitions	**1,352**	1,557	**—**	—	**—**	—	**1,352**	1,557
Proceeds from dispositions	**(25,649)**	(7,211)	**—**	(593)	**—**	—	**(25,649)**	(7,804)

As at	**December 31, 2022**	December 31, 2021
Canadian assets	**$ 2,779,596**	$ 2,658,281
U.S. assets	**2,301,047**	2,152,323
Corporate assets	**23,126**	24,039
Total consolidated assets	**$ 5,103,769**	$ 4,834,643

5. EXPLORATION AND EVALUATION ASSETS

	December 31, 2022	December 31, 2021
Balance, beginning of year	**$ 172,824**	$ 191,865
Capital expenditures	**6,359**	3,298
Property acquisitions	**301**	1,100
Divestitures	**(498)**	(166)
Property swaps	**385**	408
Impairment reversal	**22,503**	—
Exploration and evaluation expense	**(30,239)**	(15,212)
Transfers to oil and gas properties (note 6)	**(8,496)**	(7,727)
Foreign currency translation	**5,545**	(742)
Balance, end of year	**$ 168,684**	$ 172,824

At December 31, 2022, the Company identified indicators of impairment reversal for the exploration and evaluation assets within the Peace River CGU due to an increase in land sale values. The recoverable amount for the Peace River CGU exceeded its carrying value and an impairment reversal of $22.5 million was recorded at December 31, 2022. The recoverable amount was based on the CGUs FVLCD and was estimated with reference to arm's length transactions in comparable locations and the discounted cash flows associated with the Company's future development plans.

At December 31, 2021, there wereno indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's CGUs.

6. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2020	**$ 11,423,676**	**$ (8,346,128)**	**$ 3,077,548**
Capital expenditures	310,005	—	310,005
Property acquisitions	274	—	274
Transfers from exploration and evaluation assets (note 5)	7,727	—	7,727
Change in asset retirement obligations (note 9)	(12,222)	—	(12,222)
Divestitures	(37,835)	32,844	(4,991)
Property swaps	(26,131)	25,900	(231)
Impairment reversal	—	1,542,414	1,542,414
Foreign currency translation	(31,977)	34,765	2,788
Depletion	—	(458,941)	(458,941)
Balance, December 31, 2021	**$ 11,633,517**	**$ (7,169,146)**	**$ 4,464,371**
Capital expenditures	515,183	—	515,183
Property acquisitions	1,173	—	1,173
Transfers from exploration and evaluation assets (note 5)	8,496	—	8,496
Change in asset retirement obligations (note 9)	(147,020)	—	(147,020)
Divestitures	(265,166)	241,892	(23,274)
Impairment reversal	—	245,241	245,241
Foreign currency translation	296,033	(158,404)	137,629
Depletion	—	(581,033)	(581,033)
Balance, December 31, 2022	**$ 12,042,216**	**$ (7,421,450)**	**$ 4,620,766**

2022 Impairment Reversal

At December 31, 2022, the Company identified indicators of impairment reversal for oil and gas properties in five CGUs due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves. The recoverable amounts for three CGUs exceeded their carrying values which resulted in an impairment reversal of $245.2 million recorded at December 31, 2022. The recoverable amount for each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2022. The after-tax discount rates applied to the cash flows were between 12% and 23%.

At December 31, 2022, the recoverable amounts of the five CGUs were calculated using the following benchmark reference prices for the years 2023 to 2032 adjusted for commodity differentials specific to the CGU. The prices and costs subsequent to 2032 have been adjusted for inflation at an annual rate of 2.0%.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
WTI crude oil (US$/bbl)	80.33	78.50	76.95	77.61	79.16	80.74	82.36	84.00	85.69	87.40
WCS heavy oil ($/bbl)	76.54	77.75	77.55	80.07	81.89	84.02	85.73	87.44	89.20	91.11
LLS crude oil (US$/bbl)	82.83	80.68	78.81	79.49	81.07	82.68	84.33	86.00	87.71	89.46
Edmonton par oil ($/bbl)	103.76	97.74	95.27	95.58	97.07	99.01	100.99	103.01	105.07	106.69
Henry Hub gas (US$/mmbtu)	4.74	4.50	4.31	4.40	4.49	4.58	4.67	4.76	4.86	4.95
AECO gas ($/mmbtu)	4.23	4.40	4.21	4.27	4.34	4.43	4.51	4.60	4.69	4.79
Exchange rate (CAD/USD)	1.34	1.31	1.30	1.30	1.29	1.29	1.29	1.29	1.29	1.29

The following table summarizes the recoverable amount and impairment reversal for each of the five CGUs at December 31, 2022 and demonstrates the sensitivity of the impairment reversal to reasonably possible changes in key assumptions inherent in the calculation.

	Recoverable amount	Impairment reversal	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU [(1)]	$ 119,031	$ 23,707	$ —	$ —	—
Peace River CGU [(1)]	676,939	140,534	—	—	—
Lloydminster CGU	449,250	—	11,500	53,000	—
Viking CGU	1,322,193	81,000	39,500	78,000	4,000
Eagle Ford CGU	2,102,646	—	95,800	131,100	28,500
	$ 4,670,059	$ 245,241	$ 146,800	$ 262,100	$ 32,500

(1) The impairment reversals for the Conventional and Peace River CGUs were limited to the total accumulated impairments less subsequent depletion of $23.7 million and $140.5 million, respectively. As a result, changes in the key assumptions presented in the table above have no impact on the amount of the impairment reversal as at December 31, 2022.

2021 Impairment Reversals

At June 30, 2021, indicators of impairment reversal were identified for oil and gas properties in each of the Company's six CGUs due to the increase in forecasted commodity prices. The recoverable amount for each of the six CGUs exceeded their carrying amounts which resulted in an impairment reversal of $1.1 billion recorded at June 30, 2021. The recoverable amount for each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2020 and was adjusted by management for operations between December 31, 2020 and June 30, 2021. The after-tax discount rates applied to the cash flows were between 10% and 16%.

At December 31, 2021, indicators of impairment reversal were identified for oil and gas properties in five CGUs due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves. The recoverable amount for three CGUs exceeded their carrying amounts which resulted in an impairment reversal of $416 million recorded at December 31, 2021. The recoverable amount for each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2021. The after-tax discount rates applied to the cash flows were between 12% and 19%.

7. CREDIT FACILITIES

	December 31, 2022	December 31, 2021
Credit facilities - U.S. dollar denominated[1]	**$ 30,394**	$ 156,332
Credit facilities - Canadian dollar denominated	**355,000**	350,182
Credit facilities - principal [2]	**$ 385,394**	$ 506,514
Unamortized debt issuance costs	**(2,363)**	(1,343)
Credit facilities	**$ 383,031**	$ 505,171

(1) U.S. dollar denominated credit facilities balance was US$22.5 million as at December 31, 2022 (December 31, 2021 - US$123.5 million).
(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2021 to December 31, 2022 is the result of net repayments of $136.9 million, partially offset by an increase in the reported amount of U.S. denominated debt of $15.8 million due to foreign exchange.

At December 31, 2022, Baytex had US$850 million of revolving credit facilities (the "Credit Facilities"). On April 1, 2022, Baytex amended its Credit Facilities to increase the revolving credit facility to US$850 million and extend the maturity from April 1, 2024 to April 1, 2026. The Credit Facilities are comprised of a US$50 million operating loan and a US$600 million syndicated revolving loan for Baytex and a US$10 million operating loan and a US$190 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. There were no changes to the financial covenants as a result of the amendments.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity which could be extended by Baytex. Advances under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was3.6% for the year ended December 31, 2022 (2.1% for the year ended December 31, 2021).

The following table summarizes the financial covenants applicable to the Credit Facilities and the Company's compliance therewith at December 31, 2022.

Covenant Description	Position as at December 31, 2022	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.3:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**15.5:1.0**	2.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at December 31, 2022, the Company's Senior Secured Debt totaled $385.4 million.
(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the year ended December 31, 2022 was $1.2 billion.
(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the year ended December 31, 2022 was $80.2 million.

On July 25, 2022 Baytex entered into a $20 million uncommitted unsecured demand revolving letter of credit facility (the "LC Facility"). Letters of credit under this facility are guaranteed by Export Development Canada and do not use capacity available under the Credit Facilities. As at December 31, 2022, Baytex had $15.7 million of outstanding letters of credit under the LC Facility.

8. LONG-TERM NOTES

	December 31, 2022	December 31, 2021
5.625% notes due June 1, 2024 [1]	**$ —**	$ 253,120
8.75% notes due April 1, 2027 [2]	**554,597**	632,800
Total long-term notes - principal [3]	**$ 554,597**	$ 885,920
Unamortized debt issuance costs	**(6,999)**	(11,393)
Total long-term notes - net of unamortized debt issuance costs	**$ 547,598**	$ 874,527

(1) The U.S. dollar denominated principal outstanding of the 5.625% notes was nil at December 31, 2022 (December 31, 2021 - US$200.0 million).
(2) The U.S. dollar denominated principal outstanding of the 8.75% notes was US$409.8 million at December 31, 2022 (December 31, 2021 - US$500.0 million).
(3) The decrease in the principal amount of long-term notes outstanding from December 31, 2021 to December 31, 2022 is the result of principal repayments of $374.1 million and changes in the reported amount of U.S. denominated debt of $42.8 million.

The long-term notes do not contain any significant financial maintenance covenants but do contain standard commercial covenants for debt incurrence and restricted payments.

During 2022, Baytex repurchased and cancelled US$90.2 million principal of the 8.75% Notes due in 2027 and recorded early redemption expense of $2.5 million.

On June 1, 2022 Baytex completed the early redemption of the US$200.0 million principal amount of the 5.625% Notes due in 2024 at par plus accrued interest and recorded a decrease to unamortized debt issuance costs of $1.7 million.

9. ASSET RETIREMENT OBLIGATIONS

	December 31, 2022	December 31, 2021
Balance, beginning of year	**$ 743,683**	$ 760,383
Liabilities incurred	**19,942**	14,845
Liabilities settled	**(18,351)**	(6,662)
Liabilities acquired from property acquisitions	**950**	249
Liabilities divested	**(3,464)**	(3,161)
Property swaps	**—**	(4,113)
Accretion (note 15)	**15,683**	12,381
Government grants [1]	**(4,009)**	(2,857)
Change in estimate	**6,124**	(9,686)
Changes in discount rates and inflation rates [2]	**(173,086)**	(17,381)
Foreign currency translation	**1,451**	(315)
Balance, end of year	**$ 588,923**	$ 743,683
Less current portion of asset retirement obligations	**12,813**	11,080
Non-current portion of asset retirement obligations	**$ 576,110**	$ 732,603

(1) During 2022, Baytex recognized $4.0 million of non-cash other income and a reduction in asset retirement obligations related to government grants provided by the Government of Alberta and the Government of Saskatchewan ($2.9 million in 2021).
(2) The discount and inflation rates at December 31, 2022 were 3.3% and 2.1% respectively (December 31, 2021 - 1.7% and 1.8%).

At December 31, 2022, the undiscounted amount of estimated cash flows required to settle the asset retirement obligations is $724.8 million (December 31, 2021 - $721.7 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2022, calculated using an estimated inflation rate of 2.1% (December 31, 2021 - 1.8%) and a risk free discount rate of 3.3% (December 31, 2021 - 1.7%), is $588.9 million (December 31, 2021 - $743.7 million). These costs are expected to be incurred over the next 60 years.

10. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2022, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meeting of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

During 2022, the TSX accepted Baytex's notice of intention to implement an NCIB. Under the terms of the NCIB, the Company may purchase for cancellation up to 56.3 million common shares over the 12-month period commencing May 9, 2022. The number of shares authorized for repurchase represents 10% of the Company's public float as at April 29, 2022. Purchases are made on the open market at prices prevailing at the time of the transaction.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2020	**561,227**	**$ 5,729,418**
Vesting of share awards	2,986	7,175
Balance, December 31, 2021	**564,213**	**$ 5,736,593**
Vesting of share awards	5,035	8,501
Common shares repurchased and cancelled	(24,318)	(245,430)
Balance, December 31, 2022	**544,930**	**$ 5,499,664**

During 2022, Baytex repurchased and cancelled 24.3 million common shares at an average price of $6.54 per share for total consideration of $159.0 million. The total consideration paid includes the commissions and fees and is recorded as a reduction to shareholders' equity.

11. SHARE-BASED COMPENSATION PLAN

For the year ended December 31, 2022, the Company recorded total share-based compensation expense of $29.1 million ($11.1 million for the year ended December 31, 2021) which includes $25.9 million of expense related to cash-settled awards and the associated equity total return swaps ($4.7 million for the year ended December 31, 2021).

The Company's closing share price on December 31, 2022 was $6.08 (December 31, 2021 - $3.91).

Share Award Incentive Plan

Baytex has a Share Award Incentive Plan pursuant to which it issues restricted and performance awards. A restricted award entitles the holder of each award to receive one common share of Baytex or the equivalent cash value at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares or the cash equivalent value on vesting; the number of common shares issued is determined by a performance multiplier. The multiplier can range between zero and two and is calculated based on a number of factors determined and approved by the Board of Directors on an annual basis. The Share Awards vest in equal tranches on the first, second and third anniversaries of the grant date.

In December 2022, the Company received approval from its Board of Directors to settle the existing Share Awards with cash upon vesting under the terms of the Share Award Incentive Plan. As a result, Baytex recognized the fair value of the liability for amortized unvested Share Awards in trade and other payables. The fair value of the liability recognized exceeded the amount previously recognized in contributed surplus of $4.8 million and the excess was recognized as share-based compensation expense in the period.

The weighted average fair value of Share Awards granted during the year ended December 31, 2022 was $5.08 per restricted and performance award ($1.31 for the year ended December 31, 2021).

The number of Share Awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards	Total number of Share Awards
Balance, December 31, 2020	**4,122**	**4,088**	**8,210**
Granted	—	4,067	4,067
Added by performance factor	—	669	669
Vested	(1,861)	(1,152)	(3,013)
Forfeited	(168)	(291)	(459)
Balance, December 31, 2021	**2,093**	**7,381**	**9,474**
Granted	68	1,391	1,459
Vested	(1,377)	(3,630)	(5,007)
Forfeited	(22)	(346)	(368)
Balance, December 31, 2022	**762**	**4,796**	**5,558**

Incentive Award Plan

Baytex has an Incentive Award Plan whereby the holder of each incentive award is entitled to receive a cash payment equal to the value of one Baytex common share at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in trade and other payables.

During the year ended December 31, 2022, Baytex granted 1.4 million awards under the Incentive Award Plan at a fair value of $5.70 per award (5.0 million awards at $1.33 per award for the year ended December 31, 2021). At December 31, 2022 there were 5.1 million awards outstanding under the Incentive Award Plan (December 31, 2021 - 6.4 million).

DSU Plan

Baytex has a DSU Plan whereby each independent director of Baytex is entitled to receive a cash payment equal to the value of one Baytex common share on the date at which they cease to be a member of the Board. The awards vest immediately upon being granted and are expensed in full on the grant date. The units are recognized at fair value at each period end and are included in trade and other payables.

During the year ended December 31, 2022, Baytex granted 0.2 million awards under the DSU Plan at a fair value of $5.68 per award (0.9 million awards at $1.29 per award for the year ended December 31, 2021). At December 31, 2022, there were 1.0 million awards outstanding under the DSU Plan (December 31, 2021 - 0.8 million).

Equity Total Return Swaps

The Company uses equity total return swaps on the equivalent number of Baytex common shares in order to fix a portion of the aggregate cost of the Company's cash-settled plans including the Incentive Award Plan, the DSU Plan and the Share Award Incentive Plan, at the fair value determined on the grant date.

The fair value of the equity total return swap included in the carrying value of the Company's financial derivatives was nil at December 31, 2022 (December 31, 2021 - asset of $6.5 million). At December 31, 2022, an asset of $21.2 million associated with the equity total return swap was included in trade and other receivables.

12. NET INCOME PER SHARE

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted to common shares. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the year.

	Years Ended December 31					
	2022			2021		
	Net income	**Weighted average common shares (000's)**	**Net income per share**	Net income	Weighted average common shares (000's)	Net income per share
Net income - basic	**$ 855,605**	**557,986**	**$ 1.53**	$ 1,613,600	563,674	$ 2.86
Dilutive effect of share awards	**—**	**5,849**	**—**	—	7,936	—
Net income - diluted	**$ 855,605**	**563,835**	**$ 1.52**	$ 1,613,600	571,610	$ 2.82

For the year ended December 31, 2022,0.3 million shares were excluded from the calculation of diluted income per share as their effect was anti-dilutive. For the year ended December 31, 2021, no share awards were excluded from the calculation of diluted income per share as their effect was dilutive.

13. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales from contracts with customers for the Company's Canadian and U.S. operating segments is set forth in the following table.

	Years Ended December 31					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 693,043**	**$ 777,506**	**$ 1,470,549**	$ 480,199	$ 585,635	$ 1,065,834
Heavy oil	**1,102,076**	**—**	**1,102,076**	560,696	—	560,696
NGL	**30,847**	**89,658**	**120,505**	18,904	75,611	94,515
Natural gas sales	**100,595**	**95,320**	**195,915**	68,338	78,812	147,150
Total petroleum and natural gas sales	**$ 1,926,561**	**$ 962,484**	**$ 2,889,045**	$ 1,128,137	$ 740,058	$ 1,868,195

Included in accounts receivable at December 31, 2022 is $180.3 million of accrued receivables related to delivered volumes (December 31, 2021 - $154.0 million).

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2022	2021
Net income before income taxes	**$ 890,915**	$ 1,694,840
Expected income taxes at the statutory rate of 24.80% (2021 – 25.12%) [1]	**220,947**	425,744
Increase (decrease) in income taxes resulting from:		
Effect of foreign exchange	**4,976**	(841)
Effect of rate adjustments for foreign jurisdictions	**(25,522)**	(21,746)
Effect of change in deferred tax benefit not recognized [2][3]	**(129,931)**	(325,295)
Effect of internal debt restructuring	**(44,762)**	—
Adjustments, assessments and other	**9,602**	3,378
Income tax expense	**$ 35,310**	$ 81,240

(1) The expected income tax rate decreased due to changes in the provincial apportionment of Canadian income.
(2) A deferred income tax asset of $14.4 million remains unrecognized due to uncertainty surrounding future capital gains (December 31, 2021 - $29.8 million). The unrecognized deferred income tax asset relates to realized and unrealized foreign exchange losses arising from the repayment of previously issued U.S. dollar denominated long-term notes and from the translation of U.S. dollar denominated long-term notes currently outstanding.
(3) A deferred income tax asset of $115.8 million was previously unrecognized due to uncertainty surrounding commodity prices. The tax benefit associated with the deferred income tax asset has been fully recognized in the current period as a result of the impairment reversals related to oil and gas properties and E&E assets recognized for the year ended December 31, 2022.

As disclosed in the 2021 annual financial statements, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that denied $591.0 million of non-capital loss deductions that relate to the calculation of income taxes for the years 2011 through 2015. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to the Company's file in July 2018. Baytex remains confident that the original tax filings are correct and intends to defend those tax filings through the appeals process.

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2022	Recognized in Net Income	Foreign Currency Translation Adjustment	**December 31, 2022**
Taxable temporary differences:				
Petroleum and natural gas properties	$ (760,579)	$ (18,081)	$ (28,854)	**$ (807,514)**
Financial derivatives	—	(2,506)	—	**(2,506)**
Other	(21,616)	(1,137)	1,802	**(20,951)**
Deductible temporary differences:				
Asset retirement obligations	185,336	(40,693)	632	**145,275**
Financial derivatives	31,492	(31,492)	—	**—**
Non-capital losses [1][2]	342,884	18,707	12,242	**373,833**
Finance costs	55,027	43,486	4,736	**103,249**
Net deferred income tax liability [3]	$ (167,456)	$ (31,716)	$ (9,442)	**$ (208,614)**

(1) Non-capital loss carry-forwards at December 31, 2022 totaled $1.8 billion and expire from 2033 to 2040.
(2) A deferred income tax asset of $57.2 million has been recognized in respect of non-capital losses of a wholly owned financing subsidiary of Baytex; which losses will be offset against future interest income to be earned as a result of an internal debt restructuring.
(3) The net deferred income tax liability is comprised of a deferred income tax asset of $57.2 million and a deferred income tax liability of $265.9 million.

As at		January 1, 2021	Recognized in Net Loss	Foreign Currency Translation Adjustment		December 31, 2021
Taxable temporary differences:						
Petroleum and natural gas properties	$	(502,625)	$ (257,800)	$ (154)	**$**	**(760,579)**
Other		(22,377)	624	137		**(21,616)**
Deductible temporary differences:						
Asset retirement obligations		187,840	(2,436)	(68)		**185,336**
Financial derivatives		5,410	26,082	—		**31,492**
Non-capital losses [(1)]		241,514	104,479	(3,109)		**342,884**
Finance costs		3,705	49,083	2,239		**55,027**
Net deferred income tax liability	$	(86,533)	$ (79,968)	$ (955)	**$**	**(167,456)**

(1) Non-capital loss carry-forwards at December 31, 2021 totaled $2.0 billion and expire from 2033 to 2039.

15. FINANCING AND INTEREST

	Years Ended December 31			
		2022		2021
Interest on Credit Facilities	**$**	**19,550**	$	13,300
Interest on long-term notes		**60,643**		78,546
Interest on lease obligations		**193**		223
Cash interest	**$**	**80,386**	$	92,069
Amortization of debt issue costs		**6,286**		4,858
Accretion of asset retirement obligations (note 9)		**15,683**		12,381
Early redemption expense (note 8)		**2,462**		1,851
Financing and interest	**$**	**104,817**	$	111,159

16. FOREIGN EXCHANGE

	Years Ended December 31			
		2022		2021
Unrealized foreign exchange (gain) loss - intercompany notes[(1)]	**$**	**(2,674)**	$	12,000
Unrealized foreign exchange loss (gain) - long-term notes & Credit Facilities		**47,747**		(13,905)
Realized foreign exchange gain		**(1,632)**		(963)
Foreign exchange loss (gain)	**$**	**43,441**	$	(2,868)

(1) Baytex had a series of intercompany notes totaling US$601.0 million outstanding at December 31, 2021 that were issued from a Canadian functional currency subsidiary to a U.S. functional currency subsidiary. These notes were eliminated upon consolidation within the Statement of Financial Position and were revalued at the relevant foreign exchange rate at each period end. Foreign exchange gains or losses incurred within the Canadian functional currency subsidiary were recognized in unrealized foreign exchange gain or loss whereas those within the U.S. functional currency subsidiary were recognized in other comprehensive income. In January 2022, the intercompany notes were transferred from the Canadian functional currency subsidiary to another U.S. functional currency subsidiary. As a result, foreign exchange gains and losses incurred on these notes after the transfer are recognized in other comprehensive income.

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, Credit Facilities and long-term notes. The fair value of trade and other receivables and trade and other payables approximates carrying value due to the short term to maturity. The fair value of the Credit Facilities is equal to the principal amount outstanding as the Credit Facilities bear interest at floating rates and credit spreads that are indicative of market rates. The fair value of the long-term notes is determined based on market prices.

The carrying value and fair value of the Company's financial instruments carried on the consolidated statements of financial position are classified into the following categories:

	December 31, 2022		December 31, 2021		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial Derivatives	**$ 10,105**	**$ 10,105**	$ 8,654	$ 8,654	Level 2
Total	**$ 10,105**	**$ 10,105**	$ 8,654	$ 8,654	
Amortized cost					
Cash	**$ 5,464**	**$ 5,464**	$ —	$ —	—
Trade and other receivables	**228,485**	**228,485**	173,409	173,409	—
Total	**$ 233,949**	**$ 233,949**	$ 173,409	$ 173,409	
Financial Liabilities					
FVTPL					
Financial Derivatives	**$ —**	**$ —**	$ (134,020)	$ (134,020)	Level 2
Total	**$ —**	**$ —**	$ (134,020)	$ (134,020)	
Amortized cost					
Trade and other payables	**$ (281,404)**	**$ (281,404)**	$ (190,692)	$ (190,692)	—
Credit Facilities	**(383,031)**	**(385,394)**	(505,171)	(506,514)	—
Long-term notes	**(547,598)**	**(563,292)**	(874,527)	(917,889)	Level 1
Total	**$ (1,212,033)**	**$ (1,230,090)**	$ (1,570,390)	$ (1,615,095)	

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2022 or 2021.

Foreign Currency Risk

Baytex is exposed to fluctuations in foreign exchange rates as a result of the U.S. dollar portion of its Credit Facilities, long-term notes, intercompany notes, crude oil sales based on U.S. dollar benchmark prices and commodity financial derivative contracts that are settled in U.S. dollars. The Company's net income or loss, comprehensive income or loss and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

A $0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities would impact net income or loss before income taxes by approximately $4.2 million.

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities recorded in entities with a Canadian dollar functional currency at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2022	December 31, 2021	**December 31, 2022**	December 31, 2021
U.S. dollar denominated	**US$6,980**	US$602,503	**US$430,171**	US$829,934

Interest Rate Risk

The Company's interest rate risk arises from borrowing at floating rates under the Credit Facilities (note 7). Based on the principal outstanding on the Credit Facilities as at December 31, 2022, a change of 100 basis points in interest rates would impact net income or loss before income taxes by approximately $3.8 million.

Commodity Price Risk

Baytex utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivatives is governed by a Risk Management Policy approved by the Board of Directors of Baytex which sets out limits on the use of derivatives. Baytex does not use financial derivatives for speculative purposes. Baytex's financial derivative contracts are subject to master netting agreements that create a legally enforceable right to offset by the counterparty the related financial assets and financial liabilities.

When assessing the potential impact of crude oil price changes on the crude oil financial derivative contracts outstanding as at December 31, 2022, a US$1.00/bbl change in the underlying benchmark crude oil prices would impact net income before income taxes by approximately $4.7 million. There were no natural gas derivative contracts outstanding as at December 31, 2022.

Financial Derivative Contracts

Baytex had the following commodity financial derivative contracts outstanding as at February 23, 2023.

	Period	Volume	Price/Unit [(1)]	Index
Oil				
3-way option [(2)]	Jan 2023 to Dec 2023	2,000 bbl/d	US$55.00/US$66.00/US$84.00	WTI
3-way option [(2)]	Jan 2023 to Dec 2023	2,500 bbl/d	US$60.00/US$75.00/US$91.54	WTI
3-way option [(2)]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$100.00	WTI
3-way option [(2)]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$106.50	WTI
Basis Swap [(3)]	Apr 2023 to Dec 2023	1,500 bbl/d	WTI less US$2.50/bbl	MSW

(1) Based on the weighted average price per unit for the period.
(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$65.00/US$85.00/US$100.00 contract, Baytex receives WTI plus US$20.00/bbl when WTI is at or below US$65.00/bbl; Baytex receives US$85.00/bbl when WTI is between US$65.00/bbl and US$85.00/bbl; Baytex receives the market price when WTI is between US$85.00/bbl and US$100.00/bbl; and Baytex receives US$100.00/bbl when WTI is above US$100.00/bbl.
(3) Contracts entered subsequent to December 31, 2022.

The following table sets forth the realized and unrealized gains and losses recorded on financial derivatives.

	Years Ended December 31	
	2022	2021
Realized financial derivatives loss	**$ 334,481**	$ 184,241
Unrealized financial derivatives (gain) loss	**(135,471)**	103,631
Financial derivatives loss	**$ 199,010**	$ 287,872

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures.

As at December 31, 2022, Baytex had $385.4 million (December 31, 2021 - $506.5 million) of principal amounts outstanding on its Credit Facilities which have total availability of $1.2 billion (December 31, 2021 - $1.0 billion). On July 25, 2022 Baytex entered into a $20 million uncommitted unsecured demand revolving letter of credit facility (the "LC Facility"). Letters of credit under this facility are guaranteed by Export Development Canada and do not use available capacity under the Credit Facilities. As at December 31, 2022, Baytex had $15.7 million of outstanding letters of credit under the LC Facility (December 31, 2021 - $15.0 million).

The timing of cash outflows relating to financial liabilities as at December 31, 2022 is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 281,404**	$ 272,195	$ 9,209	$ —	$ —
Credit Facilities - principal [(1)]	**385,394**	—	—	385,394	—
Long-term notes - principal [(2)]	**554,597**	—	—	554,597	—
Interest on long-term notes [(3)]	**206,340**	48,527	97,054	60,759	—
Lease obligations - principal	**6,760**	3,641	2,822	297	—
	$ 1,434,495	**$ 324,363**	**$ 109,085**	**$ 1,001,047**	**$ —**

(1) On April 1, 2022, Baytex extended the maturity of the Credit Facilities to April 1, 2026.
(2) The US$409.8 million principal amount of 8.75% senior unsecured notes is due April 1, 2027.
(3) Excludes interest on Credit Facilities as interest payments on Credit Facilities fluctuate based on amounts outstanding and the prevailing interest rate at the time of borrowing.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at December 31, 2022, the Company is exposed to credit risk with respect to its trade and other receivables and financial derivatives. Baytex manages these risks through the selection and monitoring of credit-worthy counterparties.

Most of the Company's trade and other receivables relate to petroleum and natural gas sales. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts after reviewing the creditworthiness of the entity. Letters of credit or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on trade and other receivables at December 31, 2022 relates to accrued revenues. Accounts receivable from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. Included in trade and other receivables at December 31, 2022 is $180.3 million (December 31, 2021 - $154.0 million) of accrued receivables related to delivered volumes.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of trade and other receivables is reduced by adjusting the allowance for doubtful accounts and recording a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at December 31, 2022, allowance for doubtful accounts was $2.5 million (December 31, 2021 - $2.6 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2022, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was $3.0 million (December 31, 2021 - $1.8 million). Baytex has estimated the lifetime expected credit loss as at and for the year ended December 31, 2022 to be nominal.

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows at December 31, 2022.

Trade and Other Receivables Aging	**December 31, 2022**	December 31, 2021
Current (less than 30 days)	**$ 222,721**	$ 171,058
31-60 days	**1,993**	441
61-90 days	**766**	107
Past due (more than 90 days)	**3,005**	1,803
	$ 228,485	$ 173,409

18. SUPPLEMENTAL INFORMATION

Changes in Non-Cash Working Capital Items

	Years Ended December 31	
	2022	2021
Trade and other receivables	**$ (55,076)**	$ (65,932)
Trade and other payables	**90,712**	34,737
	$ 35,636	$ (31,195)
Changes in non-cash working capital related to:		
Operating activities	**$ 26,072**	$ (26,582)
Investing activities	**9,401**	(2,797)
Transfers from equity	**4,791**	—
Foreign currency translation on non-cash working capital	**(4,628)**	(1,816)
	$ 35,636	$ (31,195)

Income Statement Presentation

Baytex's consolidated statements of income and comprehensive income are prepared primarily according to the nature of expense, with the exception of employee compensation costs which are included in both operating expense and general and administrative expense line items.

The following table details the amount of total employee compensation costs included in the operating expense and general and administrative expense.

	Years Ended December 31	
	2022	2021
Operating	**$ 11,814**	$ 11,053
General and administrative	**35,935**	29,538
Total employee compensation costs	**$ 47,749**	$ 40,591

19. COMMITMENTS

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2022, and the expected timing of funding of these obligations, are noted in the table below.

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Processing agreements	**$ 6,372**	$ 1,071	$ 1,081	$ 754	$ 3,466
Transportation agreements	**195,414**	34,790	79,661	70,167	10,796
Total	**$ 201,786**	$ 35,861	$ 80,742	$ 70,921	$ 14,262

Baytex also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives (see note 9). The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statements of financial position. Programs to abandon and reclaim wellsites and facilities are undertaken regularly in accordance with applicable legislative requirements.

20. RELATED PARTIES

Transactions with key management personnel and directors are noted in the table below.

	Years Ended December 31	
	2022	2021
Short-term employee benefits	**$ 6,868**	$ 5,995
Share-based compensation	**9,043**	5,917
Termination payments	**1,758**	—
Total compensation for key management personnel	**$ 17,669**	$ 11,912

21. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute its capital programs, while meeting short and long-term commitments. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At December 31, 2022, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables, cash and the Credit Facilities.

In order to manage its capital structure and liquidity, Baytex may from time-to-time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital-intensive nature of Baytex's operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Baytex's capital resources consist primarily of Adjusted Funds Flow, available Credit Facilities and proceeds received from the divestiture of oil and gas properties. The following capital management measures and ratios are used to monitor current and projected sources of liquidity.

Net Debt

The Company uses net debt to monitor its current financial position and to evaluate existing sources of liquidity. Baytex also uses net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Baytex also uses net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor the Company's existing capital structure and future liquidity requirements.

The following table reconciles Net Debt to amounts disclosed in the primary financial statements.

	December 31, 2022	December 31, 2021
Credit Facilities	**$ 383,031**	$ 505,171
Unamortized debt issuance costs - Credit Facilities (note 7)	**2,363**	1,343
Long-term notes	**547,598**	874,527
Unamortized debt issuance costs - Long-term notes (note 8)	**6,999**	11,393
Trade and other payables	**281,404**	190,692
Cash	**(5,464)**	—
Trade and other receivables	**(228,485)**	(173,409)
Net Debt	**$ 987,446**	$ 1,409,717
Net Debt to Adjusted Funds Flow	**0.8**	1.9

Adjusted Funds Flow

Adjusted Funds Flow is used to monitor operating performance and the Company's ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirement obligations settled during the applicable period.

Adjusted Funds Flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Years Ended December 31	
	2022	2021
Cash flows from operating activities	**$ 1,172,872**	$ 712,384
Change in non-cash working capital	**(26,072)**	26,582
Asset retirement obligations settled	**18,351**	6,662
Adjusted Funds Flow	**$ 1,165,151**	$ 745,628

BAYTEX ENERGY CORP. **Exhibit 99.3**
Management's Discussion and Analysis
For the years ended December 31, 2022 and 2021
Dated February 23, 2023

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 2022 and 2021. This information is provided as of February 23, 2023. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three months and year ended December 31, 2022 ("Q4/2022" and "2022") have been compared with the results for the three months and year ended December 31, 2021 ("Q4/2021" and "2021"). This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2022 and 2021, together with the accompanying notes and the Annual Information Form ("AIF") for the year ended December 31, 2022. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

Baytex Energy Corp. is a North American focused energy company based in Calgary, Alberta. The Company operates in Canada and the United States ("U.S."). The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

2022 ANNUAL HIGHLIGHTS

Baytex delivered strong operating and financial results in 2022. We invested $521.5 million in exploration and development expenditures and generated annual production of 83,519 boe/d. Free cash flow[(1)] of $621.5 million reflects our strong financial performance for 2022 and was used for debt reduction and to initiate direct returns to shareholders.

Energy prices were strong due to uncertainty surrounding global energy security while recent concerns over high inflation and slowing economic activity have caused declines in oil prices in late 2022. The average WTI benchmark price for 2022 was US$94.23/bbl which was US$26.31/bbl higher than 2021 when WTI averaged US$67.92/bbl.

Production increased to 83,519 boe/d in 2022 compared to 80,156 boe/d in 2021 primarily from strong well results in our Clearwater program. Production was consistent with expectations and our revised annual guidance of 84,000 boe/d. Production in Canada was 55,275 boe/d in 2022 which is a 5,851 boe/d increase from 2021 driven primarily from our success in the Clearwater play at Peavine. In the U.S., production decreased to 28,245 boe/d in 2022 from 30,731 boe/d in 2021 with less activity on our lands in 2022. Exploration and development expenditures were $521.5 million for 2022 with $140.7 million invested in the U.S. and $380.8 million invested in Canada.

Adjusted funds flow[(2)] of $1.2 billion and free cash flow of $621.5 million in 2022 were higher than $745.6 million and $421.3 million for 2021, respectively, as a result of higher benchmark prices and production. Cash flows from operating activities increased to $1.2 billion in 2022 compared to $712.4 million in 2021. Our strong operating and financial results contributed to net income of $855.6 million for 2022 compared to $1.6 billion in 2021 which included impairment reversals of $1.5 billion compared to impairment reversals of $267.7 million recorded in 2022.

(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. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

We used free cash flow[1] of $621.5 million generated during 2022 for debt reduction and shareholder returns. Net debt[2] of $987.4 million at December 31, 2022 was $422.3 million lower than $1.4 billion at December 31, 2021 and we repurchased and cancelled 24.3 million common shares for $159.0 million during 2022, representing 4.3% of the shares outstanding at commencement of the normal course issuer bid.

(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. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information

GUIDANCE

In 2023, we will advance development across our high-quality asset base, further delineate our Peavine Clearwater acreage and progress our Duvernay light oil resource play. We are committed to allocating 25% of free cash flow to share buybacks until we reach our net debt target of $800 million, at which time we anticipate increasing our shareholder returns to 50% of free cash flow.

Our 2023 annual guidance includes exploration and development expenditures of $575 - $650 million and is designed to generate annual production of 86,000 - 89,000 boe/d. Additional activity and Clearwater development in 2023 will result in exploration and development expenditures of $575 - $650 million in 2023 compared to $522 million in 2022. Production growth will be driven by our Canadian assets which we expect to result in a modest increase in our per unit expected operating and transportation costs for 2023 relative to our 2022 results. We expect lower cash interest expense in 2023 relative to 2022 due to lower net debt as we continue to use free cash flow for debt repayment. We are committed to reducing our inactive wellbore count and have budgeted for $25 million of asset retirement spending in 2023 relative to $18 million in 2022.

The following table compares our 2022 revised annual guidance and 2023 annual guidance to our 2022 results. Production and exploration and development expenditures for 2022 were consistent with our 2022 revised annual guidance, as well as expenses which reflects our ongoing effort to maintain a competitive cost structure despite inflationary pressures in our industry.

	2022 Revised Annual Guidance [1]	2022 Results	2023 Annual Guidance [2]
Exploration and development expenditures	~$515 million	$522 million	$575 - $650 million
Production (boe/d)	~84,000 boe/d	83,519	86,000 - 89,000
Expenses:			
Average royalty rate [3]	21.0% - 22.0%	20.9 %	20.0% - 22.0%
Operating [4]	$13.75 - $14.25/boe	$13.86/boe	$14.00 - $14.75/boe
Transportation [4]	$1.50 - $1.60/boe	$1.59/boe	$1.90 - $2.10/boe
General and administrative [4]	$48 million ($1.57/boe)	$50 million ($1.65/boe)	$52 million ($1.63/boe)
Cash Interest [4]	$79 million ($2.58/boe)	$80 million ($2.64/boe)	$65 million ($2.04/boe)
Leasing expenditures	$3 million	$4 million	$4 million
Asset retirement obligations settled [5]	$20 million	$18 million	$25 million

(1) As announced on November 3, 2022.
(2) As announced on December 7, 2022.
(3) 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. Refer to the Specified Financial Measures section in this MD&A for further information.
(4) Refer to Operating Expense, Transportation Expense, General and Administrative Expense and Financing and Interest Expense sections of this MD&A for description of the composition of these measures.
(5) Government grants reduced asset retirement obligations by $4.0 million in 2022.

RESULTS OF OPERATIONS

The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

Production

	Years Ended December 31					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**16,060**	**17,041**	**33,101**	16,943	18,846	35,789
Heavy oil	**28,993**	**—**	**28,993**	22,188	—	22,188
Natural Gas Liquids ("NGL")	**1,896**	**5,679**	**7,575**	1,671	5,573	7,244
Total liquids (bbl/d)	**46,949**	**22,720**	**69,669**	40,802	24,419	65,221
Natural gas (mcf/d)	**49,954**	**33,146**	**83,101**	51,733	37,874	89,606
Total production (boe/d)	**55,275**	**28,245**	**83,519**	49,424	30,731	80,156
Production Mix						
Segment as a percent of total	**66 %**	**34 %**	**100 %**	62 %	38 %	100 %
Light oil and condensate	**29 %**	**60 %**	**40 %**	34 %	61 %	45 %
Heavy oil	**52 %**	**— %**	**35 %**	45 %	— %	28 %
NGL	**3 %**	**20 %**	**9 %**	3 %	18 %	9 %
Natural gas	**16 %**	**20 %**	**16 %**	18 %	21 %	18 %

Production averaged 83,519 boe/d in 2022 compared to 80,156 boe/d in 2021. Production was higher in 2022 as a result of our successful development program in Canada which included strong Clearwater well results.

In Canada, production increased to 55,275 boe/d in 2022 compared to 49,424 boe/d in 2021 due to strong well performance from our Clearwater development program at Peavine. In the U.S., production was 28,245 boe/d in 2022 compared to 30,731 boe/d for 2021 which reflects reduced activity levels in 2022. We initiated production from 68 (16.8 net) wells on our U.S. properties during 2022 compared to 93 (23.1 net) wells in 2021.

Total production of 83,519 boe/d for 2022 was consistent with our revised annual guidance of approximately 84,000 boe/d. We expect production in 2023 to average 86,000 - 89,000 boe/d with exploration and development expenditures of $575 - $650 million.

COMMODITY PRICES

The prices received for our crude oil and natural gas production directly impact our earnings, free cash flow and our financial position.

Crude Oil

Global benchmark prices for crude oil were higher throughout 2022 relative to 2021 due to strong demand and heightened geopolitical tensions. These factors resulted in the WTI benchmark price averaging US$94.23/bbl for 2022 which is US$26.31/bbl higher than US$67.92/bbl for 2021.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf coast. The MEH benchmark trades at a premium to WTI as a result of access to global markets. The MEH benchmark averaged US$97.79/bbl during 2022, representing a premium of US$3.57/bbl relative to WTI, compared to US$69.26/bbl or a premium of US$1.34/bbl for 2021. The MEH benchmark traded at a higher premium to WTI in 2022 as a result of heightened uncertainty over global supply relative to 2021.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate from period to period based on production and inventory levels in Western Canada.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $119.95/bbl for 2022 compared to $80.23/bbl for 2021. Edmonton par traded at a US$2.07/bbl discount to WTI in 2022 which is slightly narrower than a discount of US$3.92/bbl for 2021 due to higher demand for Canadian oil in 2022.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark price for 2022 averaged $98.94/bbl compared to $68.79/bbl for 2021. The WCS differential to WTI was US$18.21/bbl 2022 compared to US$13.05/bbl in 2021 due to reduced refining capacity for Canadian heavy oil following the release of oil from the U.S. Strategic Petroleum Reserve in addition to refining outages.

Natural Gas

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. Strong global demand for natural gas resulted in higher NYMEX benchmark prices in 2022 relative to 2021. The NYMEX natural gas benchmark averaged US$6.64/mmbtu for 2022 compared to US$3.84/mmbtu for 2021.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a discount to NYMEX as a result of limited market access for Canadian natural gas production. Increase global demand for natural gas resulted in higher AECO benchmark prices in 2022 relative to 2021 while maintenance on the Nova Gas Transmission Line limited export capacity from Alberta and resulted in a wider AECO basis to NYMEX of -US$2.37/mmbtu in 2022 compared to -US$1.00/mmbtu in 2021. The AECO benchmark averaged $5.56/mcf during 2022 compared to $3.56/mcf during 2021.

The following tables compare select benchmark prices and our average realized selling prices for the years ended December 31, 2022 and 2021.

	Years Ended December 31		
	2022	2021	Change
Benchmark Averages			
WTI oil (US$/bbl) [(1)]	**94.23**	67.92	26.31
MEH oil (US$/bbl) [(2)]	**97.79**	69.26	28.53
MEH oil differential to WTI (US$/bbl)	**3.57**	1.34	2.23
Edmonton par oil ($/bbl) [(3)]	**119.95**	80.23	39.72
Edmonton par oil differential to WTI (US$/bbl)	**(2.07)**	(3.92)	1.85
WCS heavy oil ($/bbl) [(4)]	**98.94**	68.79	30.15
WCS heavy oil differential to WTI (US$/bbl)	**(18.21)**	(13.05)	(5.16)
AECO natural gas price ($/mcf) [(5)]	**5.56**	3.56	2.00
NYMEX natural gas price (US$/mmbtu) [(6)]	**6.64**	3.84	2.80
CAD/USD average exchange rate	**1.3016**	1.2536	0.0480

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.
(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(4) WCS refers to the average posting price for the benchmark WCS heavy oil.
(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Years Ended December 31					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) [1]	**$ 118.23**	**$ 125.00**	**$ 121.72**	$ 77.65	$ 85.14	$ 81.59
Heavy oil, net of blending and other expense ($/bbl) [2]	**86.24**	**—**	**86.24**	58.65	—	58.65
NGL ($/bbl) [1]	**44.57**	**43.25**	**43.58**	30.99	37.17	35.74
Natural gas ($/mcf) [1]	**5.52**	**7.88**	**6.46**	3.62	5.70	4.50
Total sales, net of blending and other expense ($/boe)[2]	**$ 86.10**	**$ 93.36**	**$ 88.56**	$ 57.79	$ 65.98	$ 60.93

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.
(2) 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. Refer to the Specified Financial Measures section in this MD&A for further information.

Average Realized Sales Prices

Our total sales, net of blending and other expense per boe was $88.56/boe for 2022 compared to $60.93/boe for 2021. In Canada, our realized sales price of $86.10/boe for 2022 was higher than $57.79/boe for 2021. Our realized sales price in the U.S. was $93.36/boe in 2022 increased from $65.98/boe in 2021. The increase in our realized price in Canada and the U.S. for 2022 was a result of higher North American benchmark prices relative to 2021.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price in 2022 was $118.23/bbl compared to $77.65/bbl in 2021. Our realized light oil and condensate price for 2022 increased with the improvement in the benchmark price and represents a discount of $1.72/bbl to the Edmonton par benchmark which is relatively consistent with a discount of $2.58/bbl in 2021.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $125.00/bbl for 2022 compared to $85.14/bbl for 2021. Expressed in U.S. dollars, our realized light oil and condensate price of US$96.04/bbl for 2022 and US$67.92/bbl in 2021 represents discounts to MEH of US$1.75/bbl for 2022 which is relatively consistent with a discount of US$1.34/bbl in 2021.

Our realized heavy oil price, net of blending and other expense averaged $86.24/bbl in 2022 compared to $58.65/bbl in 2021. The increase $27.59/bbl in our realized heavy oil price, net of blending and other expense is primarily a result of the $30.15/bbl increase in WCS benchmark in 2022 compared to 2021.

Our realized NGL price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices of the underlying products. Our realized NGL price was $43.58/bbl in 2022 or 36% of WTI (expressed in Canadian dollars) compared to $35.74/bbl or 42% of WTI (expressed in Canadian dollars) in 2021.

We compare our realized natural gas price in Canada to the AECO benchmark price and to the NYMEX benchmark in the U.S. Our realized natural gas price in Canada was $5.52/mcf for 2022 compared to $3.62/mcf for 2021. The increase in our realized gas price in Canada is relatively consistent with the increase in the AECO benchmark in 2022 compared to 2021. In the U.S., our realized natural gas price of US$6.05/mcf for 2022 and US$4.55/mcf for 2021 represents a discount to NYMEX of US$0.59/mcf for 2022 compared to a premium of US$0.71/mcf for 2021 when severe weather events disrupted supply and increased demand in the U.S. Gulf coast.

PETROLEUM AND NATURAL GAS SALES

	Years Ended December 31					
	2022			2021		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 693,043**	**$ 777,506**	**$ 1,470,549**	$ 480,199	$ 585,635	$ 1,065,834
Heavy oil	**1,102,076**	**—**	**1,102,076**	560,696	—	560,696
NGL	**30,847**	**89,658**	**120,505**	18,904	75,611	94,515
Total liquids sales	**1,825,966**	**867,164**	**2,693,130**	1,059,799	661,246	1,721,045
Natural gas sales	**100,595**	**95,320**	**195,915**	68,338	78,812	147,150
Total petroleum and natural gas sales	**1,926,561**	**962,484**	**2,889,045**	1,128,137	740,058	1,868,195
Blending and other expense	**(189,454)**	**—**	**(189,454)**	(85,689)	—	(85,689)
Total sales, net of blending and other expense[1]	**$ 1,737,107**	**$ 962,484**	**$ 2,699,591**	$ 1,042,448	$ 740,058	$ 1,782,506

(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. Refer to the Specified Financial Measures section in this MD&A for further information.

Total sales, net of blending and other expense, of $2.7 billion for 2022 increased $917.1 million from $1.8 billion for 2021. The increase in total sales, net of blending and other expense, in 2022 is primarily a result of higher realized pricing along with an increase in production due to our successful development program in Canada.

In Canada, total sales, net of blending and other expense, was $1.7 billion for 2022 which is an increase of $694.7 million from $1.0 billion reported for 2021. The increase in total petroleum and natural gas sales was the result of higher realized pricing and increased production relative to 2021. Strong realized pricing resulted in a $571.2 million increase in total sales, net of blending and other expense, while higher production contributed to a $123.5 million increase in total sales, net of blending and other expense, relative to 2021.

In the U.S., petroleum and natural gas sales of $962.5 million in 2022 was $222.4 million higher than $740.1 million reported for 2021. Higher pricing resulted in a $282.3 million increase to total petroleum and natural gas sales while lower production resulted in a $59.8 million decrease in total sales relative to 2021.

ROYALTIES

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the years ended December 31, 2022 and 2021.

	Years Ended December 31					
	2022			2021		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 277,428**	**$ 285,536**	**$ 562,964**	$ 121,306	$ 217,850	$ 339,156
Average royalty rate [1][2]	**16.0 %**	**29.7 %**	**20.9 %**	11.6 %	29.4 %	19.0 %
Royalties per boe [3]	**$ 13.75**	**$ 27.70**	**$ 18.47**	$ 6.72	$ 19.42	$ 11.59

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.
(2) 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. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period.

Royalties for 2022 were $563.0 million or 20.9% of total sales, net of blending and other expense, compared to $339.2 million or 19.0% in 2021. Total royalty expense was higher in 2022 due to higher total sales, net of blending and other expense, relative to 2021. Our average royalty rate of 20.9% for 2022 is higher than 19.0% for 2021 due to a higher royalty rate on our Canadian properties as a result of higher commodity prices. Our average royalty rate of 20.9% for 2022 was slightly lower than our revised annual guidance range of 21.0% - 22.0% for 2022.

In Canada, the average royalty rate[1] was 16.0% in 2022 which was higher than 11.6% for 2021 as certain production in Canada is subject to higher royalty rates with higher benchmark commodity prices. In the U.S., the average royalty rate was 29.7% for 2022 which is consistent with 29.4% for 2021 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

We expect our average royalty rate to be within the range of 20.0% - 22.0% for 2023 which is consistent with 2022.

(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. Refer to the Specified Financial Measures section in this MD&A for further information.

OPERATING EXPENSE

	Years Ended December 31					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 327,894**	**$ 94,772**	**$ 422,666**	$ 257,658	$ 85,344	$ 343,002
Operating expense per boe [1]	**$ 16.25**	**$ 9.19**	**$ 13.86**	$ 14.28	$ 7.61	$ 11.72

(1) Operating expense per boe is calculated as operating expense divided by barrels of oil equivalent production volume for the applicable period.

Total operating expense was $422.7 million ($13.86/boe) in 2022 compared to $343.0 million ($11.72/boe) in 2021. The increase in total operating expense is due to increased production and cost inflation throughout our operations in 2022 relative to 2021. Operating expense of $13.86/boe for 2022 was at the low

end our revised annual guidance range of $13.75 - $14.25/boe.

In Canada, operating expense was $327.9 million ($16.25/boe) for 2022 compared to $257.7 million ($14.28/boe) for 2021. Our U.S. operating expense was $94.8 million ($9.19/boe) for 2022 compared to $85.3 million ($7.61/boe) for 2021. Expressed in U.S. dollars, per unit operating expense was US$7.06/boe for 2022 compared to US$6.07/boe for 2021. The increase in per unit operating expense in Canada and the U.S. was primarily due to increased costs from energy inputs resulting in higher fuel, electricity and hauling costs along with additional workover and maintenance activity in 2022 relative to 2021.

We expect annual operating expense of $14.00 - $14.75/boe for 2023 which reflects the impact of inflation and higher production from our Canadian operations relative to 2022.

TRANSPORTATION EXPENSE

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates.

The following table compares our transportation expense for the years ended December 31, 2022 and 2021.

	Years Ended December 31					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 48,561**	**$ —**	**$ 48,561**	$ 32,261	$ —	$ 32,261
Transportation expense per boe[(1)]	**$ 2.41**	**$ —**	**$ 1.59**	$ 1.79	$ —	$ 1.10

(1) Transportation expense per boe is calculated as transportation expense divided by barrels of oil equivalent production volume for the applicable period.

Transportation expense was $48.6 million ($1.59/boe) for 2022 compared to $32.3 million ($1.10/boe) for 2021. Total transportation expense and per unit costs are higher in 2022 relative to 2021 as a result of additional heavy oil production along with higher trucking rates due to higher fuel costs.

Transportation expense of $1.59/boe in 2022 was within our revised annual guidance range of $1.50 - $1.60/boe for 2022. We expect annual transportation expense of $1.90 - $2.10/boe for 2023 which is higher than 2022 as we continue to increase production in our heavy oil assets.

BLENDING AND OTHER EXPENSE

Blending and other expense primarily includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines in order to meet pipeline specifications. The purchased diluent is recorded as blending and other expense. The price received for the blended product is recorded as heavy oil sales revenue. We net blending and other expense against heavy oil sales to compare the realized price on our produced volumes to benchmark pricing.

Blending and other expense was $189.5 million for 2022 compared to $85.7 million for 2021. Higher blending and other expense reflects an increase in the price of condensate purchased as diluent along with an increase in heavy oil production shipped via pipeline in 2022 relative to 2021.

FINANCIAL DERIVATIVES

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates, interest rates and changes in our share price. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our free cash flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets fluctuate and as new contracts are entered. The following table summarizes the results of our financial derivative contracts for the years ended December 31, 2022 and 2021.

	Years Ended December 31		
($ thousands)	**2022**	2021	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ (299,788)**	$ (170,975)	$ (128,813)
Natural gas	**(34,693)**	(13,266)	(21,427)
Total	**$ (334,481)**	$ (184,241)	$ (150,240)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ 136,879**	$ (105,492)	$ 242,371
Natural gas	**5,082**	(5,749)	10,831
Equity total return swap	**(6,490)**	7,610	(14,100)
Total	**$ 135,471**	$ (103,631)	$ 239,102
Total financial derivatives gain (loss)			
Crude oil	**$ (162,909)**	$ (276,467)	$ 113,558
Natural gas	**(29,611)**	(19,015)	(10,596)
Equity total return swap	**(6,490)**	7,610	(14,100)
Total	**$ (199,010)**	$ (287,872)	$ 88,862

We recorded a financial derivatives loss of $199.0 million for 2022 compared to a loss of $287.9 million for 2021. The realized financial derivatives loss for 2022 of $334.5 million was a result of the market prices for crude oil and natural gas settling at levels above the prices set in our derivative contracts. The unrealized financial derivatives gain of $135.5 million for 2022 is primarily due to changes in forecasted crude oil pricing used to revalue the volumes outstanding on our crude oil contracts in place at December 31, 2022 relative to December 31, 2021. The fair value of our financial derivative contracts resulted in a net asset of $10.1 million at December 31, 2022 compared to a net liability of $125.4 million at December 31, 2021.

Baytex had the following commodity financial derivative contracts as at February 23, 2023.

	Period	Volume	Price/Unit [1]	Index
Oil				
3-way option [2]	Jan 2023 to Dec 2023	2,000 bbl/d	US$55.00/US$66.00/US$84.00	WTI
3-way option [2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$60.00/US$75.00/US$91.54	WTI
3-way option [2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$100.00	WTI
3-way option [2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$106.50	WTI
Basis Swap [3]	Apr 2023 to Dec 2023	1,500 bbl/d	WTI less US$2.50/bbl	MSW

(1) Based on the weighted average price per unit for the period.
(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$65.00/US$85.00/US$100.00 contract, Baytex receives WTI plus US$20.00/bbl when WTI is at or below US$65.00/bbl; Baytex receives US$85.00/bbl when WTI is between US$65.00/bbl and US$85.00/bbl; Baytex receives the market price when WTI is between US$85.00/bbl and US$100.00/bbl; and Baytex receives US$100.00/bbl when WTI is above US$100.00/bbl.
(3) Contracts entered subsequent to December 31, 2022.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the years ended December 31, 2022 and 2021.

	Years Ended December 31					
	2022			2021		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**55,275**	**28,245**	**83,519**	49,424	30,731	80,156
Operating netback:						
Total sales, net of blending and other expense[1]	**$ 86.10**	**$ 93.36**	**$ 88.56**	$ 57.79	$ 65.98	$ 60.93
Less:						
Royalties [2]	**(13.75)**	**(27.70)**	**(18.47)**	(6.72)	(19.42)	(11.59)
Operating expense [2]	**(16.25)**	**(9.19)**	**(13.86)**	(14.28)	(7.61)	(11.72)
Transportation expense [2]	**(2.41)**	**—**	**(1.59)**	(1.79)	—	(1.10)
Operating netback [1]	**$ 53.69**	**$ 56.47**	**$ 54.64**	$ 35.00	$ 38.95	$ 36.52
Realized financial derivatives loss [3]	**—**	**—**	**(10.97)**	—	—	(6.30)
Operating netback after financial derivatives [1]	**$ 53.69**	**$ 56.47**	**$ 43.67**	$ 35.00	$ 38.95	$ 30.22

(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. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.
(3) Calculated as realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our operating netback of $54.64/boe for 2022 was higher than $36.52/boe for 2021 due to an increase in benchmark pricing in Canada and the U.S. which resulted in higher per unit sales, net of royalties. Total operating expense and transportation expense of $15.45/boe was higher than $12.82/boe in 2021 due to inflation which resulted in higher fuel, electricity and hauling costs along with increased workover and maintenance activity in 2022. Including realized losses on financial derivatives, our operating netback was $43.67/boe for 2022 compared to $30.22/boe for 2021.

GENERAL AND ADMINISTRATIVE EXPENSE

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs and administrative recoveries earned for operating exploration and development activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated exploration and development activity during the period.

The following table summarizes our G&A expense for the years ended December 31, 2022 and 2021.

	Years Ended December 31		
($ thousands except for per boe)	**2022**	2021	Change
Gross general and administrative expense	**$ 55,785**	$ 44,368	$ 11,417
Overhead recoveries	**(5,515)**	(3,564)	(1,951)
General and administrative expense	**$ 50,270**	$ 40,804	$ 9,466
General and administrative expense per boe[(1)]	**$ 1.65**	$ 1.39	$ 0.26

(1) General and administrative expense per boe is calculated as general and administrative expense divided by barrels of oil equivalent production volume for the applicable period.

G&A expense was $50.3 million ($1.65/boe) for 2022 compared to $40.8 million ($1.39/boe) for 2021. G&A expense was $9.5 million higher relative to 2021 due to higher staffing costs associated with increased activity levels in Canada and inflation during 2022. G&A expense of $50.3 million ($1.65/boe) for 2022 was consistent with expectations and was slightly above our revised annual guidance of $48 million ($1.57/boe). We expect annual G&A expense of $52 million ($1.63/boe) for 2023.

FINANCING AND INTEREST EXPENSE

Financing and interest expense includes interest on our credit facilities, long-term notes and lease obligations as well as non-cash financing costs which include the accretion on our debt issue costs and asset retirement obligations. Financing and interest expense varies depending on debt levels outstanding during the period, the applicable borrowing rates, CAD/USD foreign exchange rates, along with the carrying amount of asset retirement obligations and the discount rates used to present value these obligations.

The following table summarizes our financing and interest expense for the years ended December 31, 2022 and 2021.

	Years Ended December 31		
($ thousands except for per boe)	**2022**	2021	Change
Interest on credit facilities	**$ 19,550**	$ 13,300	$ 6,250
Interest on long-term notes	**60,643**	78,546	(17,903)
Interest on lease obligations	**193**	223	(30)
Cash interest	**$ 80,386**	$ 92,069	$ (11,683)
Amortization of debt issue costs	**6,286**	4,858	1,428
Accretion of asset retirement obligations	**15,683**	12,381	3,302
Early redemption expense	**$ 2,462**	$ 1,851	611
Financing and interest expense	**$ 104,817**	$ 111,159	$ (6,342)
Cash interest per boe[(1)]	**$ 2.64**	$ 3.15	$ (0.51)
Financing and interest expense per boe[(1)]	**$ 3.44**	$ 3.80	$ (0.36)

(1) Calculated as cash interest or financing and interest expense divided by barrels of oil equivalent production volume for the applicable period.

Financing and interest expense was $104.8 million ($3.44/boe) in 2022 compared to $111.2 million ($3.80/boe) in 2021. Lower debt levels have resulted in reduced financing and interest expense in 2022 relative to 2021.

Cash interest of $80.4 million ($2.64/boe) in 2022 was lower than $92.1 million ($3.15/boe) in 2021 as we had less debt outstanding during 2022. The interest on our long-term notes was lower as the average principal amount outstanding was lower in 2022 due to the repurchase and redemption of US$200 million of long-term notes during 2021 and US$290.2 million during 2022. Interest on our credit facilities was higher in 2022 relative to 2021 consistent with the increase in benchmark borrowing rates. The weighted average interest rate applicable on our credit facilities was 3.6% in 2022 compared to 2.1% in 2021.

Financing and interest expense for 2022 includes the accelerated amortization of debt issue costs and $2.5 million of early redemption expense associated with the redemption of $90.2 million principal amount of the 8.75% Notes in 2022. Accretion of asset retirement obligations of $15.7 million for 2022 was higher than $12.4 million for 2021 due to higher discount rates in 2022 relative to 2021.

Cash interest of $80.4 million ($2.64/boe) for 2022 was consistent with our revised annual guidance of $79 million ($2.58/boe). We expect cash interest to be $65 million ($2.04/boe) for 2023 as we continue to reduce the amount of debt in our capital structure.

EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $30.2 million for 2022 compared to $15.2 million for 2021.

DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the years ended December 31, 2022 and 2021.

	Years Ended December 31		
($ thousands except for per boe)	**2022**	2021	Change
Depletion	**$ 581,033**	$ 458,941	$ 122,092
Depreciation	**6,017**	5,639	378
Depletion and depreciation	**$ 587,050**	$ 464,580	$ 122,470
Depletion and depreciation per boe[(1)]	**$ 19.26**	$ 15.88	$ 3.38

(1) Depletion and depreciation expense per boe is calculated as depletion and depreciation expense divided by barrels of oil equivalent production volume for the applicable period.

Depletion and depreciation expense was $587.1 million ($19.26/boe) for 2022 compared to $464.6 million ($15.88/boe) reported for 2021. Total depletion and depreciation expense as well as the depletion and depreciation rate per boe were higher in 2022 relative to 2021 as a result of $1.5 billion of impairment reversals recorded during 2021 which increased the depletable base of our oil and gas properties.

IMPAIRMENT

2022 Impairment Reversal

At December 31, 2022, we identified indicators of impairment reversal for oil and gas properties in five of our six cash-generating units ("CGUs") due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves. We recorded an impairment reversal for oil and gas properties of $245.2 million as the estimated recoverable amounts in three of our CGUs exceeded their carrying values. At December 31, 2022, we identified indicators of impairment reversal for E&E assets in the Peace River CGU due to an increase in land sale values and recorded an impairment reversal of $22.5 million. The total impairment reversal recorded at December 31, 2022 was $267.7 million.

At December 31, 2022, the recoverable amount of oil and gas properties for the five CGUs were calculated using the following benchmark reference prices for the years 2023 to 2032 adjusted for commodity differentials specific to the CGU. The prices and costs subsequent to 2032 have been adjusted for inflation at an annual rate of 2.0%.

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
WTI crude oil (US$/bbl)	80.33	78.50	76.95	77.61	79.16	80.74	82.36	84.00	85.69	87.40
WCS heavy oil ($/bbl)	76.54	77.75	77.55	80.07	81.89	84.02	85.73	87.44	89.20	91.11
LLS crude oil (US$/bbl)	82.83	80.68	78.81	79.49	81.07	82.68	84.33	86.00	87.71	89.46
Edmonton par oil ($/bbl)	103.76	97.74	95.27	95.58	97.07	99.01	100.99	103.01	105.07	106.69
Henry Hub gas (US$/mmbtu)	4.74	4.50	4.31	4.40	4.49	4.58	4.67	4.76	4.86	4.95
AECO gas ($/mmbtu)	4.23	4.40	4.21	4.27	4.34	4.43	4.51	4.60	4.69	4.79
Exchange rate (CAD/USD)	1.34	1.31	1.30	1.30	1.29	1.29	1.29	1.29	1.29	1.29

The following table summarizes the recoverable amount and impairment reversal for each of the five CGUs at December 31, 2022 and demonstrates the sensitivity of the impairment reversal to reasonably possible changes in key assumptions inherent in the calculation.

	Recoverable amount	Impairment Reversal	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU [(1)]	$ 119,031	$ 23,707	$ —	$ —	$ —
Peace River CGU [(1)]	676,939	140,534	—	—	—
Lloydminster CGU	449,250	—	11,500	53,000	—
Viking CGU	1,322,193	81,000	39,500	78,000	4,000
Eagle Ford CGU	2,102,646	—	95,800	131,100	28,500
	$ 4,670,059	$ 245,241	$ 146,800	$ 262,100	$ 32,500

(1) The impairment reversals for the Conventional and Peace River CGUs were limited to total accumulated impairments less subsequent depletion of $23.7 million and $140.5 million, respectively. As a result, changes in the key assumptions presented in the table above have no impact on the amount of the impairment as at December 31, 2022.

2021 Impairment Reversals

We identified indicators of impairment reversal for oil and gas properties in each of our six CGU's at June 30, 2021 and December 31, 2021 due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves which resulted in total impairment reversals of $1.5 billion recorded during 2021.

SHARE-BASED COMPENSATION EXPENSE

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan, Incentive Award Plan, and Deferred Share Unit Plan. SBC expense associated with equity-classified awards is recognized in net income or loss over the vesting period of the awards with a corresponding increase in contributed surplus. SBC expense associated with cash-settled awards is recognized in net income or loss over the vesting period of the awards with a corresponding financial liability included in trade and other payables, and includes gains or losses on equity total return swaps. SBC expense varies with the quantity of unvested share awards outstanding and the grant date fair value assigned to the share awards.

We recorded SBC expense of $29.1 million for 2022 which is higher than $11.1 million reported for 2021. The total expense for 2022 is comprised of non-cash compensation expense of $3.2 million (2021 - $6.4 million) and cash compensation expense of $25.9 million (2021 - $4.7 million) related to cash-settled awards and the associated equity total return swap. In December 2022, we received approval from our Board of Directors to settle the existing Share Awards with cash upon vesting under the terms of the Share Award Incentive Plan. Total SBC expense for 2022 is higher relative to 2021 as a result of the fair value adjustment recorded on conversion of our employee compensation plans from equity-settled to cash-settled.

FOREIGN EXCHANGE

Unrealized foreign exchange gains and losses are primarily a result of changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities in our Canadian functional currency entities. The long-term notes and credit facilities are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate resulting in unrealized gains and losses. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

	Years Ended December 31		
($ thousands except for exchange rates)	**2022**	2021	Change
Unrealized foreign exchange loss (gain)	**$ 45,073**	$ (1,905)	$ 46,978
Realized foreign exchange gain	**(1,632)**	(963)	(669)
Foreign exchange loss (gain)	**$ 43,441**	$ (2,868)	$ 46,309
CAD/USD exchange rates:			
At beginning of period	**1.2656**	1.2755	
At end of period	**1.3534**	1.2656	

We recorded a foreign exchange loss of $43.4 million for 2022 compared to a gain of $2.9 million for 2021.

The unrealized foreign exchange loss of $45.1 million for 2022 is primarily related to changes in the reported amount of our long-term notes and credit facilities due to a weakening of the Canadian dollar relative to U.S. dollar at December 31, 2022 compared to December 31, 2021. The unrealized foreign exchange gain of $1.9 million for 2021 relates to the remeasurement of our long-term notes, intercompany notes and credit facilities due to the changes in the value of the Canadian dollar relative to the U.S. dollar at December 31, 2021 compared to December 31, 2020.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange gain of $1.6 million for 2022 compared to $1.0 million for 2021.

INCOME TAXES

	Years Ended December 31		
($ thousands)	**2022**	2021	Change
Current income tax expense	**$ 3,594**	$ 1,272	$ 2,322
Deferred income tax expense	**31,716**	79,968	(48,252)
Total income tax expense	**$ 35,310**	$ 81,240	$ (45,930)

Current income tax expense was $3.6 million for 2022 compared to $1.3 million recorded in 2021. Current income tax is higher in 2022 due to higher state tax owed on our U.S. operations.

We recorded deferred income tax expense of $31.7 million for 2022 compared to $80.0 million for 2021. The deferred income tax expense in 2022 is lower compared to the expense recorded in 2021 due to lower net income before income taxes recorded in 2022.

As disclosed in the 2021 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA") that deny $591.0 million of non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. In September 2016, we filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to our file in July 2018. We remain confident that our original tax filings are correct and intend to defend these tax filings through the appeals process.

The following table summarizes our Canadian and U.S. tax pools.

Canadian Tax Pools *($ thousands)*	**December 31, 2022**	December 31, 2021
Canadian oil and natural gas property expenditures	**$ 355,028**	$ 406,475
Canadian development expenditures	**483,270**	480,814
Undepreciated capital costs	**275,987**	287,170
Non-capital losses	**818,326**	996,556
Financing costs and other	**62,442**	12,835
Total Canadian tax pools	**$ 1,995,053**	$ 2,183,850
U.S. Tax Pools *($ thousands)*		
Depletion	**$ 139,013**	$ 136,505
Intangible drilling costs	**—**	1,898
Tangibles	**14,483**	23,949
Net operating losses	**813,753**	992,258
Other	**96,157**	152,509
Total U.S. tax pools	**$ 1,063,406**	$ 1,307,119

NET INCOME

Net income for the years ended December 31, 2022 and 2021 are set forth in the following table.

	Years Ended December 31		
($ thousands)	**2022**	2021	Change
Petroleum and natural gas sales	**$ 2,889,045**	$ 1,868,195	$ 1,020,850
Royalties	**(562,964)**	(339,156)	(223,808)
Revenue, net of royalties	**2,326,081**	1,529,039	797,042
Expenses			
Operating	**(422,666)**	(343,002)	(79,664)
Transportation	**(48,561)**	(32,261)	(16,300)
Blending and other	**(189,454)**	(85,689)	(103,765)
Operating netback [(1)]	**$ 1,665,400**	$ 1,068,087	$ 597,313
General and administrative	**(50,270)**	(40,804)	(9,466)
Cash interest	**(80,386)**	(92,069)	11,683
Realized financial derivatives loss	**(334,481)**	(184,241)	(150,240)
Realized foreign exchange gain	**1,632**	963	669
Other expense	**(7,253)**	(295)	(6,958)
Current income tax expense	**(3,594)**	(1,272)	(2,322)
Cash share-based compensation	**(25,897)**	(4,741)	(21,156)
Adjusted funds flow [(2)]	**$ 1,165,151**	$ 745,628	$ 419,523
Exploration and evaluation	**(30,239)**	(15,212)	(15,027)
Depletion and depreciation	**(587,050)**	(464,580)	(122,470)
Non-cash share-based compensation	**(3,159)**	(6,389)	3,230
Non-cash financing and interest	**(24,431)**	(19,090)	(5,341)
Non-cash other income	**4,009**	2,857	1,152
Unrealized financial derivatives gain (loss)	**135,471**	(103,631)	239,102
Unrealized foreign exchange (loss) gain	**(45,073)**	1,905	(46,978)
Gain on dispositions	**4,898**	9,666	(4,768)
Impairment reversal	**267,744**	1,542,414	(1,274,670)
Deferred income tax expense	**(31,716)**	(79,968)	48,252
Net income	**$ 855,605**	$ 1,613,600	$ (757,995)

(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. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

We generated adjusted funds flow of $1.2 billion for 2022 compared to $745.6 million for 2021. The $419.5 million increase in adjusted funds flow for 2022 is primarily due to higher operating netback which increased $597.3 million as a result of higher commodity prices that increased revenues, net of royalties. The increase in operating netback was partially offset by a $150.2 million increase in realized financial derivative losses.

We reported net income of $855.6 million for 2022 compared to $1.6 billion for 2021. The decrease in net income for 2022 relative to 2021 is primarily a result of the $1.5 billion impairment reversal recorded in 2021 exceeding the $267.7 million impairment reversal recorded in 2022. The decrease in net income was partially offset by a $239.1 million increase in unrealized financial derivative gains.

OTHER COMPREHENSIVE INCOME

Other comprehensive income is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation gain of $124.1 million for 2022 relates to the change in value of our U.S. net assets and is due to the weakening of the Canadian dollar relative to the U.S. dollar at December 31, 2022 compared to December 31, 2021. The CAD/USD exchange rate was 1.3534 CAD/USD at December 31, 2022 compared to 1.2656 CAD/USD at December 31, 2021.

CAPITAL EXPENDITURES

Capital expenditures for the years ended December 31, 2022 and 2021 are summarized as follows.

	Years Ended December 31					
	2022			2021		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 321,836**	**$ 136,746**	**$ 458,582**	$ 182,761	$ 102,985	$ 285,746
Facilities	**32,573**	**3,151**	**35,724**	18,213	924	19,137
Land, seismic and other	**26,393**	**843**	**27,236**	7,236	1,184	8,420
Exploration and development expenditures	**$ 380,802**	**$ 140,740**	**$ 521,542**	$ 208,210	$ 105,093	$ 313,303
Property acquisitions	**$ 1,352**	**$ —**	**$ 1,352**	$ 1,557	$ —	$ 1,557
Proceeds from dispositions	**$ (25,649)**	**$ —**	**$ (25,649)**	$ (7,211)	$ (593)	$ (7,804)

Exploration and development expenditures were $521.5 million for 2022 compared to $313.3 million for 2021. Exploration and development expenditures were higher as development increased with stronger commodity prices in 2022 along with inflationary pressures that have resulted in higher costs relative to 2021.

In Canada, exploration and development expenditures were $380.8 million in 2022 which is $172.6 million higher than $208.2 million in 2021. Drilling and completion spending of $321.8 million in 2022 reflects higher light and heavy oil development activity relative to 2021 when we spent $182.8 million. We also invested $32.6 million on facilities, $26.4 million on land, seismic and other expenditures and completed a minor non-core property disposition in our conventional business unit in West Central Alberta for proceeds of $25.6 million. Exploration and development expenditures in 2022 include costs associated with drilling 140 (134.3 net) light oil wells, 63 (60.1 net) heavy oil wells and 2 (2.0 net) conventional oil and gas wells. Exploration and development expenditures of $208.2 million for 2021 include costs associated with drilling 125 (123.2 net) light oil wells, 37 (33.5 net) heavy oil wells and 2 (2.0 net) conventional natural gas wells.

Total U.S. exploration and development expenditures were $140.7 million for 2022 which is $35.6 million higher than $105.1 million for 2021. Exploration and development expenditures of $140.7 million for 2022 include costs associated with the drilling of 64 (15.8 net) wells along with completing 68 (16.8 net) wells that were brought on production in the year. The timing and pace of development activity along with inflationary pressures and weaker Canadian dollar resulted in exploration and development expenditures that were higher than 2021 when we spent $105.1 million and drilled 67 (15.5 net) wells and brought 93 (23.1 net) wells on production.

Total exploration and development expenditures of $521.5 million for 2022 was consistent with our revised annual guidance of approximately $515 million. We expect annual exploration and development expenditures of $575 - $650 million for 2023 which reflects the impact of inflation and additional activity in Canada relative to 2022.

CAPITAL RESOURCES AND LIQUIDITY

Our objective for capital management is to maintain a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions. At December 31, 2022, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables, cash and the credit facilities.

In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital intensive nature of our operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties.

Management of debt levels is a priority for Baytex in order to sustain operations and support long-term plans. At December 31, 2022, net debt[(1)] of $987.4 million was $422.3 million lower than $1.4 billion at December 31, 2021. The decrease in net debt for 2022 is primarily a result of free cash flow[(2)] of $621.5 million generated during 2022 being allocated to debt repayment which was partially offset by $159.0 million in common share repurchases completed in conjunction with our shareholder returns initiative.

In May 2022, we began repurchasing our common shares under a previously announced normal course issuer bid ("NCIB") as part of our shareholder return framework. During 2022 we spent $159.0 million to repurchase and cancel 24.3 million common shares at an average price of $6.54 per share, representing 4.3% of the total shares outstanding at the commencement of the NCIB.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a trailing twelve month basis. At December 31, 2022, our net debt to adjusted funds flow ratio[(1)] was 0.8 compared to a ratio of 1.9 as at December 31, 2021. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2021 is attributed to higher adjusted funds flow during 2022 and lower net debt as at December 31, 2022.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) 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. Refer to the Specified Financial Measures section in this MD&A for further information.

Credit Facilities

At December 31, 2022, we had $385.4 million of principal amount outstanding under our revolving credit facilities which total US$850 million (the "Credit Facilities"). On April 1, 2022, we amended the Credit Facilities to expand our revolving capacity to US$850 million and extended the maturity to April 1, 2026. The Credit Facilities are comprised of a US$50 million operating loan and a US$600 million syndicated revolving loan for Baytex and a US$10 million operating loan and a US$190 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex energy USA, Inc.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. There are no mandatory principal payments required prior to maturity which could be extended upon our request. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. Advances under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was 3.6% for 2022 as compared to 2.1% for 2021. The interest rate on our Credit Facilities has increased with higher government benchmark rates in 2022 relative to 2021.

On July 25, 2022 we entered into a $20 million uncommitted unsecured demand revolving letter of credit facility (the "LC Facility"). Letters of credit under this facility are guaranteed by Export Development Canada and do not use available capacity under the Credit Facilities. As at December 31, 2022, we had $15.7 million of outstanding letters of credit under the LC Facility.

The agreements and associated amending agreements relating to the Credit Facilities are accessible on the SEDAR website at www.sedar.com.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at December 31, 2022.

Covenant Description	Position as at December 31, 2022	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.3:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**15.5:1.0**	2.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the credit facilities and other secured obligations identified in the credit facility agreement. As at December 31, 2022, the Company's Senior Secured Debt totaled $385.4 million.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended December 31, 2022 was $1.2 billion.

(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the twelve months ended December 31, 2022 were $80.2 million.

Long-Term Notes

We have one series of long-term notes outstanding with a total principal amount of $554.6 million as at December 31, 2022. The long-term notes do not contain any financial maintenance covenants.

On February 5, 2020, we issued US$500 million aggregate principal amount of senior unsecured notes due April 1, 2027 bearing interest at a rate of 8.75% per annum payable semi-annually (the "8.75% Senior Notes"). The 8.75% Senior 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. During 2022, Baytex repurchased and cancelled an aggregate principal amount of US$90.2 million of the 8.75% Notes.

On June 1, 2022, we redeemed and cancelled the remaining US$200 million principal amount of the 5.625% notes due June 1, 2024.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the year ended December 31, 2022, we issued 5.0 million common shares pursuant to our share-based compensation program and cancelled 24.3 million repurchased under a NCIB. As at February 23, 2023, we had 544.9 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2022 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 281,404**	$ 272,195	$ 9,209	$ —	$ —
Credit Facilities - principal [1]	**385,394**	—	—	385,394	—
Long-term notes - principal [2]	**554,597**	—	—	554,597	—
Interest on long-term notes [3]	**206,340**	48,527	97,054	60,759	—
Lease obligations - principal	**6,760**	3,641	2,822	297	
Processing agreements	**6,372**	1,071	1,081	754	3,466
Transportation agreements	**195,414**	34,790	79,661	70,167	10,796
Total	**$ 1,636,281**	$ 360,224	$ 189,827	$ 1,071,968	$ 14,262

(1) On April 1, 2022 we extended the maturity of our credit facilities to April 1, 2026.

(2) The US$409.8 million principal amount of 8.75% senior unsecured notes is due April 1, 2027.

(3) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

FOURTH QUARTER OPERATING AND FINANCIAL RESULTS

	Three Months Ended December 31					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total daily production						
Light oil and condensate (bbl/d)	**14,511**	**17,594**	**32,105**	16,388	18,598	34,986
Heavy oil (bbl/d)	**32,819**	**—**	**32,819**	23,482	—	23,482
NGL (bbl/d)	**1,958**	**5,703**	**7,661**	1,713	6,271	7,984
Total liquids (bbl/d)	**49,288**	**23,297**	**72,585**	41,583	24,869	66,452
Natural gas (mcf/d)	**45,953**	**39,726**	**85,679**	52,673	33,356	86,029
Total production (boe/d)	**56,946**	**29,918**	**86,864**	50,362	30,428	80,789
Operating netback ($/boe)						
Light oil and condensate ($/bbl) [1]	**$ 108.21**	**$ 114.64**	**$ 111.73**	$ 91.17	$ 97.68	$ 94.63
Heavy oil, net of blending and other expense ($/bbl) [2]	**64.06**	**—**	**64.06**	67.76	—	67.76
NGL ($/bbl) [1]	**39.68**	**38.36**	**38.70**	41.73	39.42	39.92
Natural gas ($/mcf) [1]	**5.38**	**6.93**	**6.10**	4.65	6.70	5.44
Total sales, net of blending and other per boe [2]	**70.20**	**83.94**	**74.93**	67.54	75.17	70.42
Royalties per boe [3]	**(10.06)**	**(25.06)**	**(15.23)**	(8.15)	(22.28)	(13.47)
Operating expense per boe [3]	**(15.98)**	**(7.48)**	**(13.06)**	(15.37)	(8.63)	(12.83)
Transportation expense per boe [3]	**(2.83)**	**—**	**(1.85)**	(1.76)	—	(1.10)
Operating netback per boe [2]	**$ 41.33**	**$ 51.40**	**$ 44.79**	$ 42.26	$ 44.26	$ 43.02
Financial						
Petroleum and natural gas sales	**$ 417,952**	**$ 231,034**	**$ 648,986**	$ 341,966	$ 210,437	$ 552,403
Royalties	**(52,718)**	**(68,973)**	**(121,691)**	(37,770)	(62,382)	(100,152)
Revenue, net of royalties	**365,234**	**162,061**	**527,295**	304,196	148,055	452,251
Operating	**(83,742)**	**(20,593)**	**(104,335)**	(71,203)	(24,154)	(95,357)
Transportation	**(14,817)**	**—**	**(14,817)**	(8,169)	—	(8,169)
Blending and other	**(50,174)**	**—**	**(50,174)**	(29,021)	—	(29,021)
Operating netback [2]	**$ 216,501**	**$ 141,468**	**$ 357,969**	$ 195,803	$ 123,901	$ 319,704
General and administrative	**—**	**—**	**(14,945)**	—	—	(11,481)
Cash interest	**—**	**—**	**(19,711)**	—	—	(21,319)
Realized financial derivatives (loss) gain	**—**	**—**	**(49,665)**	—	—	(70,544)
Other	**—**	**—**	**(18,096)**	—	—	(1,594)
Adjusted funds flow [4]	**$ 216,501**	**$ 141,468**	**$ 255,552**	$ 195,803	$ 123,901	$ 214,766
Net income	**$ 366,104**	**$ 88,480**	**$ 352,807**	$ 526,412	$ 72,457	$ 563,239
Exploration and development expenditures	**$ 85,641**	**$ 17,993**	**$ 103,634**	$ 59,821	$ 14,174	$ 73,995
Property acquisitions	**$ 1,085**	**$ —**	**$ 1,085**	$ 1,443	$ —	$ 1,443
Proceeds from dispositions	**$ (148)**	**$ —**	**$ (148)**	$ (6,857)	$ —	$ (6,857)
Net debt [4]			**$ 987,446**			$ 1,409,717

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.
(2) 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. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Calculated as royalties expense, operating expense or transportation expense divided by barrels of oil equivalent production volume for the applicable period.
(4) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

	Three Months Ended December 31		
	2022	2021	Change
Benchmark Averages			
WTI oil (US$/bbl) [1]	**82.64**	77.19	5.45
MEH oil (US$/bbl) [2]	**85.88**	78.89	6.99
MEH oil differential to WTI (US$/bbl)	**3.24**	1.70	1.54
Edmonton par oil ($/bbl) [3]	**109.57**	93.29	16.28
Edmonton par oil differential to WTI (US$/bbl)	**(1.94)**	(3.15)	1.21
WCS heavy oil ($/bbl) [4]	**77.37**	78.82	(1.45)
WCS heavy oil differential to WTI (US$/bbl)	**(25.65)**	(14.63)	(11.02)
AECO natural gas price ($/mcf) [5]	**5.58**	4.94	0.64
NYMEX natural gas price (US$/mmbtu) [6]	**6.26**	5.83	0.43
CAD/USD average exchange rate	**1.3577**	1.2600	0.0977

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.
(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(4) WCS refers to the average posting price for the benchmark WCS heavy oil.
(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

Our operating and financial results for Q4/2022 reflect the successful execution of our 2022 development programs and strong benchmark commodity prices. We invested $103.6 million on exploration and development expenditures in Q4/2022 and delivered production of 86,864 boe/d. Free cash flow[1] was $143.3 million in Q4/2022 which reflects strong commodity prices and the disciplined execution of our development programs.

In Canada, production averaged 56,946 boe/d in Q4/2022 which was 6,584 boe/d higher than 50,362 boe/d reported for Q4/2021 as a result of our successful Clearwater program and higher development activity in 2022 relative to 2021. Strong benchmark pricing resulted in our realized price of $70.20/boe for Q4/2022 which was $2.66/boe higher than $67.54/boe for Q4/2021. In Q4/2022, the Edmonton Par benchmark increased to $109.57/bbl compared to $93.29/bbl for the same period in 2021. This increase was partially offset by a lower WCS heavy oil benchmark which decreased slightly to $77.37/bbl in Q4/2022 from $78.82/bbl for the same period of 2021. Higher commodity prices and production resulted in an operating netback[1] of $216.5 million ($41.33/boe) for Q4/2022 which was $20.7 million ($0.93/boe) higher than $195.8 million ($42.26/boe) reported for Q4/2021. Exploration and development expenditures of $85.6 million in Q4/2022 includes drilling costs associated with 51 (49.6 net) wells and bringing 49 (47.4 net) wells on production. This is compared to 57 (57.0 net) wells drilled and 37 (36.7 net) wells brought on production in Q4/2021 when we spent $59.8 million. The increase in exploration and development expenditures in 2022 reflects higher activity and inflationary pressures that have resulted in higher costs relative to 2021.

In the U.S., production averaged 29,918 boe/d for Q4/2022 which is 510 boe/d lower than 30,428 boe/d reported for Q4/2021 reflecting reduced activity levels in 2022. The MEH benchmark averaged US$85.88/bbl in Q4/2022 which was US$6.99/boe higher than US$78.89/bbl during Q4/2021 resulting in an increased realized price of $83.94/boe which was $8.77/boe higher than our realized price of $75.17/boe in Q4/2021. Operating netback of $141.5 million ($51.40/boe) was $17.6 million ($7.14/boe) higher than $123.9 million ($44.26/boe) for Q4/2021 due to higher benchmark prices in Q4/2022. Exploration and development expenditures of $18.0 million in Q4/2022 includes costs associated with drilling 11 (2.2 net) and commencing production from 12 (4.1 net) wells. Exploration and development expenditures were higher in Q4/2022 due to a weaker Canadian dollar, inflationary pressures and the timing of drilling and completion activity relative to Q4/2021 when we spent $14.2 million and drilled 15 (4.4 net) wells and brought 14 (2.5 net) wells on production.

(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. Refer to the Specified Financial Measures section in this MD&A for further information.

We generated adjusted funds flow[1] of $255.6 million in Q4/2022 which is $40.8 million higher than $214.8 million in Q4/2021 due to higher production and strong realized pricing. Production increased to 86,864 boe/d in Q4/2022 from 80,789 boe/d for Q4/2021 driven by the success of our development programs in the U.S. and Canada. Operating netback[2] of $44.79/boe in Q4/2022 is $1.77/boe higher than $43.02/boe in Q4/2021 and reflects higher benchmark prices. The increase in our realized price combined with the impact of higher production resulted in an $38.3 million increase in operating netback in Q4/2022 compared to Q4/2021. We recorded realized financial derivatives losses of $49.7 million in Q4/2022 compared to losses of $70.5 million in Q4/2021. G&A expense of $14.9 million in Q4/2022 was higher than $11.5 million in Q4/2021. Interest expense of $19.7 million in Q4/2022 was $1.6 million lower than $21.3 million for Q4/2021 due to a decrease in our net debt and a decrease in our long-term notes outstanding following the redemption of US$290.2 million of our long-term notes during 2022. Net debt[1] decreased from $1.4 billion in Q4/2021 to $987.4 million in Q4/2022 due to free cash flow generated in 2022.

We recorded net income of $352.8 million in Q4/2022 compared to $563.2 million in Q4/2021. The decrease in net income for Q4/2022 relative to Q4/2021 is primarily a result of a larger impairment reversal in Q4/2021. Net income for Q4/2022 includes $267.7 million of impairment reversals due to improvements in forecasted commodity prices while Q4/2021 includes $416.0 million of impairment reversals.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) 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. Refer to the Specified Financial Measures section in this MD&A for further information.

QUARTERLY FINANCIAL INFORMATION

	2022				2021			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**648,986**	712,065	854,169	673,825	552,403	488,736	442,354	384,702
Net income (loss)	**352,807**	264,968	180,972	56,858	563,239	32,714	1,052,999	(35,352)
Per common share - basic	**0.65**	0.48	0.32	0.10	1.00	0.06	1.87	(0.06)
Per common share - diluted	**0.64**	0.47	0.32	0.10	0.98	0.06	1.85	(0.06)
Adjusted funds flow [1]	**255,552**	284,288	345,704	279,607	214,766	198,397	175,883	156,582
Per common share - basic	**0.47**	0.51	0.61	0.49	0.38	0.35	0.31	0.28
Per common share - diluted	**0.46**	0.51	0.60	0.49	0.37	0.35	0.31	0.28
Free cash flow [2]	**143,324**	111,568	245,316	121,318	137,133	101,215	112,486	70,495
Per common share - basic	**0.26**	0.20	0.43	0.21	0.24	0.18	0.20	0.13
Per common share - diluted	**0.26**	0.20	0.43	0.21	0.24	0.18	0.20	0.13
Cash flows from operating activities	**303,441**	310,423	360,034	198,974	240,567	178,961	171,876	120,980
Per common share - basic	**0.56**	0.56	0.63	0.35	0.43	0.32	0.30	0.22
Per common share - diluted	**0.55**	0.56	0.63	0.35	0.42	0.31	0.30	0.22
Exploration and development expenditures	**103,634**	167,453	96,633	153,822	73,995	94,235	61,485	83,588
Canada	**85,641**	117,150	51,881	126,130	59,821	75,499	30,387	42,503
U.S.	**17,993**	50,303	44,752	27,692	14,174	18,736	31,098	41,085
Property acquisitions	**1,085**	—	208	59	1,443	89	—	25
Proceeds from dispositions	**(148)**	(25,460)	(14)	(27)	(6,857)	(701)	(18)	(228)
Net debt [1]	**987,446**	1,113,559	1,123,297	1,275,680	1,409,717	1,564,658	1,629,629	1,758,894
Total assets [3]	**5,103,769**	4,923,617	4,870,432	4,917,811	4,834,643	4,453,971	4,438,162	3,338,408
Common shares outstanding	**544,930**	547,615	560,139	569,214	564,213	564,213	564,182	564,111
Daily production								
Total production (boe/d)	**86,864**	83,194	83,090	80,867	80,789	79,872	81,162	78,780
Canada (boe/d)	**56,946**	55,803	54,919	53,385	50,362	48,124	47,205	52,039
U.S. (boe/d)	**29,918**	27,391	28,170	27,482	30,428	31,748	33,957	26,741
Benchmark prices								
WTI oil (US$/bbl)	**82.64**	91.56	108.41	94.29	77.19	70.56	66.07	57.84
WCS heavy ($/bbl)	**77.37**	93.62	122.05	100.99	78.82	71.81	67.03	57.46
Edmonton Light ($/bbl)	**109.57**	116.79	137.79	115.66	93.29	83.78	77.28	66.58
CAD/USD avg exchange rate	**1.3577**	1.3059	1.2766	1.2661	1.2600	1.2601	1.2279	1.2663
AECO gas ($/mcf)	**5.58**	5.81	6.27	4.59	4.94	3.54	2.85	2.93
NYMEX gas (US$/mmbtu)	**6.26**	8.20	7.17	4.95	5.83	4.01	2.83	2.69
Total sales, net of blending and other expense ($/boe) [2]	**74.93**	87.68	105.44	86.89	70.42	63.85	57.19	51.84
Royalties ($/boe) [4]	**(15.23)**	(19.21)	(22.69)	(16.86)	(13.47)	(12.32)	(11.04)	(9.44)
Operating expense ($/boe) [4]	**(13.06)**	(14.39)	(14.21)	(13.85)	(12.83)	(11.46)	(11.22)	(11.36)
Transportation expense ($/boe) [4]	**(1.85)**	(1.67)	(1.56)	(1.27)	(1.10)	(1.06)	(1.01)	(1.24)
Operating netback ($/boe) [2]	**44.79**	52.41	66.98	54.91	43.02	39.01	33.92	29.80
Financial derivatives gain (loss) ($/boe) [4]	**(6.21)**	(9.98)	(16.41)	(11.59)	(9.49)	(7.34)	(5.28)	(2.93)
Operating netback after financial derivatives ($/boe) [2]	**38.58**	42.43	50.57	43.32	33.53	31.67	28.64	26.87

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) 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. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Previously disclosed amounts have been revised to conform with current period presentation
(4) Calculated as royalties expense, operating expenses, transportation expense or financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our results for the previous eight quarters reflect the disciplined execution of our capital programs as oil and natural gas prices have strengthened. Production steadily increased from 78,780 boe/d in Q1/2021 to 86,864 boe/d in Q4/2022 as a result of increased development activity following improvements in commodity pricing which increased from their lows set during the COVID-19 pandemic. Strong well performance and our successful development programs have resulted in production of 86,864 boe/d for Q4/2022.

Prices began to strengthen in 2021 as measures to control the spread of COVID-19 were relaxed. Commodity prices continued to improve to multi-year highs in 2022 following Russia's invasion of Ukraine which created elevated uncertainty surrounding the global supply of oil and natural gas. The impact of increased commodity prices is reflected in our realized price of $105.44/boe for Q2/2022 which is our strongest realized pricing in eight quarters. Our Q4/2022 realized price of $74.93/boe reflects recent declines in crude oil prices caused by concern over future demand and economic slowdowns.

Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow[(1)] of $255.6 million for Q4/2022 reflects strong price realizations and production results from our development plans in the U.S. and Canada.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt[(1)] has decreased from $1.8 billion at Q1/2021 to $987.4 million at Q4/2022 as free cash flow[(2)] of $1.0 billion generated over the last eight quarters has been primarily directed towards debt repayment. The decrease in net debt due to free cash flow was partially offset by our shareholder return initiative which was implemented during Q2/2022 and resulted in the repurchase and cancellation of 24.3 million common shares for total consideration of $159.0 million as of Q4/2022. The decrease in net debt was also partially offset by the impact of foreign exchange as the CAD/USD exchange rate used to translate our U.S. dollar denominated debt increased from 1.2572 CAD/USD at Q1/2021 to 1.3534 CAD/USD at Q4/2022.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) 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. Refer to the Specified Financial Measures section in this MD&A for further information.

ENVIRONMENTAL REGULATIONS

As a result of our involvement in the exploration for and production of oil and natural gas we are subject to various emissions, carbon and other environmental regulations. Refer to the Risk Factors section of this MD&A for a full description of the risks associated with these regulations and how they may impact our business in the future. In addition to the Risk Factors discussed in this MD&A, additional information related to our emissions and sustainability initiatives is available on our website.

Reporting Regulations

Environmental reporting for public enterprises continues to evolve and we may be subject to additional future disclosure requirements. The International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 *Disclosure of Climate-related Matters* which sets forth additional reporting requirements for Canadian Public Companies. We continue to monitor developments on these reporting requirements and have not yet quantified the cost to comply with these regulations.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2022, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information, including considerations related to environmental regulation and related matters, available to the Company at the time of financial statement preparation. Actual results can differ from those estimates as the effect of future events cannot be determined with certainty. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and NGL reserves in the calculation of depletion, evaluating the recoverability of deferred income tax assets and in the determination of fair value estimates for non-financial assets. The process to estimate

reserves is complex and requires significant judgment. Estimates of the Company's reserves are evaluated annually by independent reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL and the related net cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGL and their future net cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forward price forecasts, production rates, ultimate reserve recovery, timing and amount of capital expenditures, production costs, marketability of oil and natural gas, royalty rates and other geological, economic and technical factors could have a significant impact on reported reserves. Changes in the Company's reserves estimates can have a significant impact on the carrying values of the Company's oil and gas properties, the calculation of depletion, the valuation of deferred income tax assets, the timing of cash flows for asset retirement obligations, asset impairments and estimates of fair value determined in accounting for business combinations.

CGUs

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment and Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. The assessment for each CGU considers significant changes in reservoir performance including forecasted production volumes, forecasted royalty, operating, capital and abandonment and reclamation costs, forecasted oil and gas prices and the resulting cash flows from proved plus probable oil and gas reserves. The assessment for E&E assets considers arm's length sale transactions and significant changes in the Company's development plans.

Measurement of Recoverable Amount

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including cash flows associated with proved plus probable oil and gas reserves, the discount rate used to present value future cash flows, and assumptions regarding the timing and amount of capital expenditures and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

E&E Assets

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. The determination of technical feasibility and commercial viability of E&E assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment. Management uses the establishment of commercial reserves as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets are tested for impairment and reclassified to oil and natural gas properties.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future, and discount and inflation rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. Actual abandonment and reclamation costs could be materially different from estimated amounts.

Income Taxes

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

SPECIFIED FINANCIAL MEASURES

In this MD&A, we refer to certain specified financial measures (such as free cash flow, operating netback, total sales, net of blending and other expense, heavy oil sales, net of blending and other expense per bbl, and average royalty rate) which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

Total sales, net of blending and other expense and heavy oil, net of blending and other expense

Total sales, net of blending and other expense and heavy oil, net of blending and other expense represent the total revenues and heavy oil revenues realized from produced volumes during a period, respectively. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. Heavy oil, net of blending and other expense is calculated as heavy oil sales less blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

The following table reconciles heavy oil, net of blending and other expense to amounts disclosed in the primary financial statements in the following table.

	Years Ended December 31	
($ thousands)	**2022**	2021
Petroleum and natural gas sales	**$ 2,889,045**	$ 1,868,195
Light oil and condensate [(1)]	**(1,470,549)**	$ (1,065,834)
NGL [(1)]	**(120,505)**	(94,515)
Natural gas sales [(1)]	**(195,915)**	(147,150)
Heavy oil sales	**1,102,076**	560,696
Blending and other expense - heavy oil [(2)]	**$ (189,454)**	$ (85,689)
Heavy oil, net of blending and other expense	**$ 912,622**	$ 475,007

(1) Component of petroleum and natural gas sales; see Note 13 Petroleum and Natural Gas Sales in the Consolidated Financial Statements for the year ended December 31, 2022 for further information.
(2) The portion of blending and other expense that relates to heavy oil sales for the applicable period.

Operating netback

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

The following table reconciles operating netback and operating netback after realized financial derivatives to petroleum and natural gas sales.

	Years Ended December 31	
($ thousands)	**2022**	2021
Petroleum and natural gas sales	**$ 2,889,045**	$ 1,868,195
Blending and other expense	**(189,454)**	(85,689)
Total sales, net of blending and other expense	**2,699,591**	1,782,506
Royalties	**(562,964)**	(339,156)
Operating expense	**(422,666)**	(343,002)
Transportation expense	**(48,561)**	(32,261)
Operating netback	**1,665,400**	1,068,087
Realized financial derivatives loss [(1)]	**(334,481)**	(184,241)
Operating netback after realized financial derivatives	**$ 1,330,919**	$ 883,846

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss; see Note 17 Financial Instruments and Risk Management in the Consolidated Financial Statements for the year ended December 31, 2022 for further information.

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties and payments on lease obligations.

Free cash flow is reconciled to cash flows from operating activities in the following table.

	Years Ended December 31	
($ thousands)	**2022**	2021
Cash flows from operating activities	**$ 1,172,872**	$ 712,384
Change in non-cash working capital	**(26,072)**	$ 26,582
Additions to exploration and evaluation assets	**(6,359)**	(3,298)
Additions to oil and gas properties	**(515,183)**	(310,005)
Payments on lease obligations	**(3,732)**	(4,334)
Free cash flow	**$ 621,526**	$ 421,329

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

Heavy oil, net of blending and other expense per bbl represents the realized price for produced heavy oil volumes during a period. Heavy oil, net of blending and other expense is a non-GAAP measure that is divided by barrels of heavy oil production volume for the applicable period to calculate the ratio. We use heavy oil, net of blending and other expense per bbl to analyze our realized heavy oil price for produced volumes against the WCS benchmark price.

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

Average royalty rate

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure). The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

Operating netback per boe

Operating netback per boe is operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Capital Management Measures

Net debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net debt is comprised of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, cash, and trade and other receivables. We also use a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor our existing capital structure and future liquidity requirements. Net debt to adjusted funds flow is comprised of net debt divided by twelve-month trailing adjusted funds flow.

The following table summarizes our calculation of net debt.

($ thousands)		**December 31, 2022**		December 31, 2021
Credit facilities	**$**	**383,031**	$	505,171
Unamortized debt issuance costs - Credit facilities[(1)]		**2,363**		1,343
Long-term notes		**547,598**		874,527
Unamortized debt issuance costs - Long-term notes[(1)]		**6,999**		11,393
Trade and other payables		**281,404**		190,692
Cash		**(5,464)**		—
Trade and other receivables		**(228,485)**		(173,409)
Net debt	**$**	**987,446**	$	1,409,717
Net debt to adjusted funds flow		**0.8**		1.9

(1) Unamortized debt issuance costs were obtained from Note 7 Credit Facilities and Note 8 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2022. These amounts represent the remaining balance of costs that were paid by Baytex at the inception of the contract.

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirement obligations settled during the applicable period.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

		Years Ended December 31		
($ thousands)		**2022**		2021
Cash flows from operating activities	**$**	**1,172,872**	$	712,384
Change in non-cash working capital		**(26,072)**		26,582
Asset retirement obligations settled		**18,351**		6,662
Adjusted funds flow	**$**	**1,165,151**	$	745,628

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2022, an evaluation was conducted to determine the effectiveness of our “disclosure controls and procedures” (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”) and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers

concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

It should be noted that while the certifying officers believe that our disclosure control and procedures provide a reasonable level of assurance that they are effective, they do not expect that our disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control system are met.

Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control over our financial reporting is a process designed under the supervision of and with the participation of management, including the certifying officers, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2022.

The effectiveness of our internal control over financial reporting as of December 31, 2022 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their Report of Independent Registered Public Accounting Firm.

Changes in Internal Control over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2022 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

SELECTED ANNUAL INFORMATION

The following table summarizes key annual financial and operating information over the three most recently completed financial years.

($ thousands, except per common share amounts)	**2022**	2021	2020
Revenues, net of royalties	**$ 2,326,081**	$ 1,529,039	$ 811,742
Adjusted funds flow [(1)]	**$ 1,165,151**	$ 745,628	$ 311,506
Per common share - basic	**$ 2.09**	$ 1.32	$ 0.56
Per common share - diluted	**$ 2.07**	$ 1.30	$ 0.56
Net income (loss)	**$ 855,605**	$ 1,613,600	$ (2,438,964)
Per common share - basic	**$ 1.53**	$ 2.86	$ (4.35)
Per common share - diluted	**$ 1.52**	$ 2.82	$ (4.35)
Total assets	**$ 5,103,769**	$ 4,834,643	$ 3,408,096
Credit facilities - principal	**$ 385,394**	$ 506,514	$ 651,173
Long-term notes - principal	**$ 554,597**	$ 885,920	$ 1,147,950
Total sales, net of blending and other expense ($/boe)[(2)]	**$ 88.56**	$ 60.93	$ 31.75
Total production (boe/d)	**83,519**	80,156	79,781

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) 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. Refer to the Specified Financial Measures section in this MD&A for further information.

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document 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", "plan", "project", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: our intentions of allocating our annual free cash flow to shareholder returns through share buybacks and debt reduction; that production growth will be driven by our Canadian assets; our commitment to reduce our inactive wellbore count; for 2023, our capital budget, expected average daily production, expected royalty rate and operating expense, transportation expense, general and administrative expense, cash interest expense, lease expenditures and asset retirement obligations settled; the existence, operation and strategy of our risk management program; the reassessment of our tax filings by the Canada Revenue Agency; that we may issue or repurchase debt or equity securities from time to time or sell assets; our intent to fund certain financial obligations with cash flow from operations and the expected timing of the financial obligations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

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 volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; 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; 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; 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 of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; 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; the risk that we may not have sufficient financial resources in the future to provide shareholder returns; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2022, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2023 and in our other public filings.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes. There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does 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.

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial and operational results. Listed below is a description of these risks and uncertainties.

Risks Relating to Our Business and Operations

Volatility of oil and natural gas prices and price differentials

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 arising from Russia's invasion of Ukraine, the impact of pandemics/epidemics (including Covid-19), government regulation, political stability in the Middle East and elsewhere, 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. 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.

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 IFRS. 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.

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, it is highly likely that 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 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.

Physical Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rain fall, hurricanes 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 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.

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 could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include 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.

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 Company 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 Company'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 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.

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. 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.

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.

We are not the operator of our drilling locations in our Eagle Ford acreage 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 our Eagle Ford acreage 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.

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. Any such reassessment may have an impact on current and future taxes payable. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries.

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.

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.

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.

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.

Environment

All phases of our operations are subject to environmental and health and safety regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations (collectively, "environmental regulations") governing occupational health and safety, the spill, release or emission of substances into the environment or otherwise relating to environmental protection. Environmental regulations require that wells, facility sites and other properties associated with our operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. The jurisdictions where we operate have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. Changes to the requirements of liability management programs may result in significant increases to the security that must be posted, the timing of our abandonment and reclamation operations and the costs associated with such operations.

Compliance with environmental regulations can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties. Failure to comply with environmental regulations may result in the imposition of administrative, civil and criminal penalties or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties regardless of

negligence or fault. Although it is not expected that the costs of complying with environmental regulations will have a material adverse effect on our financial condition or results of operations, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect. The implementation of new environmental regulations or the modification of existing environmental regulations could reduce demand for crude oil and natural gas, result in stricter standards and enforcement, larger penalties and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition, results of operations or prospects.

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.

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 Company'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.

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

The Company undertakes or intends to undertake certain hydraulic fracturing, SAGD, CSS and waterflooding programs. To undertake such operations the Company needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Company 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 Company 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 Company is ultimately able to produce from its reserves.

Regulations regarding the disposal of fluids used in the Company'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 Company'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.

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

There is a risk that interest rates will continue to rise from recent historical lows. 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 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, 2022 are estimated using forecast prices and costs. 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.

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: 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. The Company competes 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 Company. As a result, some of the Company's competitors may have greater opportunities and be able to access, services or vendors that the Company is not able to access, thereby limiting its ability to compete.

Our information technology systems are subject to certain risks

We utilize 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 Company'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 Company 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 Company's business, financial condition and results of operations.

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

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

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.

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.

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.

Indigenous Claims

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

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.

The future acquisition by the Company of Common Shares is uncertain

The future acquisition by the Company of Common Shares pursuant to a share buyback (including through its NCIB), if any, and the level thereof is uncertain. Any decision to 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 Company'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 and satisfaction of the solvency tests imposed on the Company under applicable corporate law. There can be no assurance of the number of Common Shares that the Company will acquire pursuant to a share buyback, if any, in the future.

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 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 may not be comparable to United States standards.

As a consequence of the foregoing, our reserves estimates and production volumes 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.

Exhibit 99.4

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Eric T. Greager, certify that:

1. I have reviewed this annual report on Form 40-F of Baytex Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: February 23, 2023 BAYTEX ENERGY CORP.

/s/ *Eric T. Greager*
Name: Eric T. Greager
Title: President and Chief Executive Officer

Exhibit 99.5

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Chad L. Kalmakoff, certify that:

1. I have reviewed this annual report on Form 40-F of Baytex Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: February 23, 2023 BAYTEX ENERGY CORP.

/s/ *Chad L. Kalmakoff*
Name: Chad L. Kalmakoff
Title: Chief Financial Officer

Exhibit 99.6

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Baytex Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Eric T. Greager, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 23, 2023 BAYTEX ENERGY CORP.

/s/ *Eric T. Greager*
Name: Eric T. Greager
Title: President and Chief Executive Officer

Exhibit 99.7

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Baytex Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Chad L. Kalmakoff, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 23, 2023 BAYTEX ENERGY CORP.

/s/ *Chad L. Kalmakoff*
Name: Chad L. Kalmakoff
Title: Chief Financial Officer

Exhibit 99.8

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Baytex Energy Corp.:

We consent to the use of:

- our report dated February 23, 2023 on the consolidated financial statements of Baytex Energy Corp. (the "Company") which comprise the consolidated statements of financial position as of December 31, 2022 and 2021, the related consolidated statements of income and comprehensive income, changes in equity, and cash flows for the years then ended, and the related notes, and
- our report dated February 23, 2023 on the effectiveness of the Company's internal control over financial reporting as of December 31, 2022

each of which is included in the Annual Report on Form 40-F of the Company for the fiscal year ended December 31, 2022.

We also consent to the incorporation by reference of such reports in the Registration Statement (No. 333-171568) on Form S-8 of the Company.

/s/ KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 23, 2023

Exhibit 99.9

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated February 2, 2023 and effective December 31, 2022, evaluating the proved and probable petroleum and natural gas reserves attributable to Baytex Energy Corp. and its affiliates (collectively, the "Company"), which is entitled "Baytex Energy Corp., Evaluation of Petroleum Reserves, based on Forecast Prices and Costs, As of December 31, 2022" (the "Report").

We hereby consent to the references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and to the incorporation by reference in Registration Statements No. 333-171568 on Form S-8 of the Company and to the use of the Report.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2022 dated February 23, 2023, and that we have no reason to believe that there are any misrepresentations in the information contained therein that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

Yours truly,
MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ *Brian R. Hamm*
Brian R. Hamm, P. Eng.
President & CEO

Calgary, Alberta, Canada
February 23, 2023

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2022

Exhibit 99.10

The following disclosures have been prepared by Baytex Energy Corp. ("Baytex" or the "Company") in accordance with Accounting Standards Codification 932 "Extractive Activities - Oil & Gas" ("ASC 932") issued by the Financial Accounting Standards Board. The standard requires the use of a 12 month average price to estimate proved reserves calculated as the unweighted arithmetic average of first-day-of-the-month prices within the 12 month period prior to the end of the reporting period.

Petroleum and Natural Gas Reserves Information

Users of this information should be aware that the process of estimating quantities of "proved developed" and "proved undeveloped" crude oil, natural gas liquids, bitumen and natural gas is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Future fluctuations in prices and costs, production rates, or changes in political or regulatory environments could cause the Company's reserves to be materially different from that presented.

Proved petroleum and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids ("NGL") that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed petroleum and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, which may require future expenditures.

Proved undeveloped petroleum and natural gas reserves are reserves that are expected to be recovered from known accumulations where a future expenditure is required.

Proved reserves and production volumes are presented net of royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production. Figures reported as natural gas reserves and production volumes do not include flared gas, injected gas or gas consumed in operations. All natural gas reserves and production volumes presented are sales volumes. Undrilled locations underlying the estimates of our proved undeveloped reserves as of December 31, 2021 and 2022 are included in a development plan that was adopted by Baytex for the applicable year as a result of our annual long-range planning process and associated corporate financial model and all such locations were scheduled to be drilled within five years of the initial development plan adoption date.

The changes in Baytex's net proved crude oil, NGL, bitumen and natural gas reserves under constant prices and costs for the two-year period ended December 31, 2022 were as follows:

	Canada				United States			
	Crude Oil (mbbl)	**NGL** (mbbl)	**Bitumen** (mbbl)	**Natural Gas** (mmcf)	**Crude Oil** (mbbl)	**NGL** (mbbl)	**Bitumen** (mbbl)	**Natural Gas** (mmcf)
Net proved reserves								
December 31, 2020	35,639	2,044	4,883	54,367	35,127	48,393	—	154,589
Revisions of previous estimates	28,031	729	175	31,805	1,393	250	—	5,583
Improved recovery	—	—	—	—	—	—	—	—
Purchases of minerals in place	57	—	—	—	—	—	—	—
Extensions and discoveries	37,694	3,223	—	42,652	2,128	2,799	—	10,180
Production	(11,977)	(580)	(568)	(16,973)	(3,819)	(2,736)	—	(10,187)
Sales of minerals in place	(12)	(17)	—	(486)	(14)	(5)	—	(25)
December 31, 2021	89,431	5,400	4,490	111,364	34,814	48,701	—	160,140
Revisions of previous estimates	3,663	1,189	552	11,699	(334)	(320)	—	(15,019)
Improved recovery	—	—	—	—	—	—	—	—
Purchases of minerals in place	—	—	—	—	—	—	—	—
Extensions and discoveries	11,765	1,246	—	14,540	280	286	—	733
Production	(12,848)	(614)	(577)	(15,818)	(3,752)	(2,350)	—	(8,914)
Sales of minerals in place	(1)	(643)	—	(22,996)	—	—	—	—
December 31, 2022	92,009	6,579	4,465	98,790	31,008	46,317	—	136,940
Net proved developed reserves								
End of year 2020	20,749	1,616	808	37,858	15,809	21,277	—	67,187
End of year 2021	41,918	2,184	592	68,498	18,750	22,334	—	72,257
End of year 2022	46,815	2,436	898	63,494	19,681	20,725	—	60,453

	Canada				United States			
	Crude Oil (mbbl)	NGL (mbbl)	Bitumen (mbbl)	Natural Gas (mmcf)	Crude Oil (mbbl)	NGL (mbbl)	Bitumen (mbbl)	Natural Gas (mmcf)
Net proved undeveloped reserves								
End of year 2020	14,889	428	4,075	16,508	19,318	27,116	—	87,402
End of year 2021	47,513	3,216	3,898	42,866	16,064	26,368	—	87,882
End of year 2022	45,194	4,143	3,567	35,295	11,327	25,592	—	76,487

	Total				
	Crude Oil (mbbl)	NGL (mbbl)	Bitumen (mbbl)	Natural Gas (mmcf)	Total (mboe)
Net proved reserves					
December 31, 2020	70,766	50,437	4,883	208,956	160,912
Revisions of previous estimates	29,423	980	175	37,387	36,809
Improved recovery	—	—	—	—	—
Purchases of minerals in place	57	—	—	—	57
Extensions and discoveries	39,822	6,022	—	52,832	54,649
Production	(15,797)	(3,316)	(568)	(27,160)	(24,208)
Sales of minerals in place	(26)	(22)	—	(511)	(133)
December 31, 2021	124,245	54,101	4,490	271,504	228,087
Revisions of previous estimates	3,329	869	552	(3,320)	4,196
Improved recovery	—	—	—	—	—
Purchases of minerals in place	—	—	—	—	—
Extensions and discoveries	12,045	1,532	—	15,273	16,122
Production	(16,600)	(2,964)	(577)	(24,732)	(24,262)
Sales of minerals in place	(1)	(643)	—	(22,996)	(4,476)
December 31, 2022	123,017	52,895	4,465	235,729	219,666
Net proved developed reserves					
End of year 2020	36,559	22,894	808	105,045	77,768
End of year 2021	60,668	24,518	592	140,755	109,237
End of year 2022	66,496	23,160	898	123,947	111,213
Net proved undeveloped reserves					
End of year 2020	34,207	27,544	4,075	103,910	83,144
End of year 2021	63,578	29,584	3,898	130,749	118,851
End of year 2022	56,521	29,735	3,567	111,782	108,453

Revisions of Previous Estimates

In 2021, the Company realized total proved revisions of 36,809 mboe. These revisions consisted of: (i) positive revisions of 29,574 mboe in Canada and 3,182 mboe in the United States ("U.S.") due to an increase in YE 2021 constant pricing as compared to YE 2020 (WTI increased to US$66.55/bbl from US$39.54/bbl), (ii) positive revisions of 7,576 mboe in our Heavy oil assets and 344 mboe in our Duvernay assets as a result of improved performance as compared to previous forecasts, (iii) negative revisions of 2,417 mboe in our Viking assets and 609 mboe in our Eagle Ford assets due to lower performance as compared to previous forecasts, and (iv) negative revisions of 841 mboe due to capital plan changes in our Conventional assets.

In 2022, the Company realized total net proved revisions of 4,196 mboe. These revisions consisted of: (i) positive revisions of 10,904 mboe, of which 8,840 mboe was in Canada and 2,064 mboe was in the U.S., due to an increase in YE 2022 constant pricing as compared to YE 2021 (WTI increased to US$94.14/bbl from US$66.55/bbl), (ii) net negative revisions of 6,709 mboe, of which net negative 5,221 mboe have been realized in our U.S. assets (negative 15,019 mmcf in shale gas) and net negative 1,488 mboe in Canada (negative 6,085 mboe in our Viking asset) due to higher field operating costs resulting from inflationary impacts truncating end of life forecasts and variation in actual performance and forecasted performance.

Extensions and Discoveries

In 2021, the Company added 54,649 mboe of net proved reserves These revisions consisted of positive revisions of 48,026 in Canada and 6,623 in the U.S. due to drilling activity undertaken in 2021.

In 2022, the Company added net proved reserves of 16,122 mboe. In Canada, 15,434 mboe net proved reserves were added as a result of our 2022 drilling activity, of which 8,635 mboe are attributed to our heavy oil assets (7,040 mboe in Peace River and 1,595 mboe in our Lloydminster areas). In the U.S., the Company added 688 mboe net proved reserves due to 2022 drilling.

Sales of Minerals in Place

In 2022, the Company divested 4,475 mboe net proved reserves as a result of a property disposition in our Conventional asset in Canada.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Petroleum and Natural Gas Reserves

The following information has been developed utilizing procedures prescribed by ASC 932 and based on crude oil, NGL and natural gas reserves and production volumes estimated by Baytex's independent reserves evaluator, McDaniel & Associates Consultants Ltd. The methodology used in calculating our price assumptions for the standardized measure of discounted future net cash flows for reserves estimation is based upon the average first-day-of-the-month prices during the year.

Future production and development costs are based on forecast price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after providing for the tax cost of the petroleum and natural gas properties based upon existing laws and regulations. A 10% discount factor was applied to the future net cash flows.

The information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the fair market value of Baytex's petroleum and natural gas properties. Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated. The prescribed discount rate of 10% may not appropriately reflect interest rates.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on an unweighted arithmetic average of the first-day-of-the-month price for each month in 2022 and 2021.

	Commodity Pricing	
	2022	**2021**
WTI crude (US$/bbl)	$ 94.14	$ 66.55
Edmonton Light crude (Cdn$/bbl)	$ 119.13	$ 78.15
Western Canadian Select crude (WCS) [1] (Cdn$/bbl)	$ 97.68	$ 66.43
AECO spot (Cdn$/mmbtu)	$ 5.62	$ 3.57
Henry Hub (US$/mmbtu)	$ 6.25	$ 3.64
Exchange rate (US$/Cdn$)	0.7710	0.7980

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

The standardized measure of discounted future net cash flows relating to net proved petroleum and natural gas reserves are as follows:

	Canada		United States		Total [2]	
(thousands of Canadian dollars)	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**
Future cash inflows	$ 10,216,200	$ 6,585,366	$ 8,202,831	$ 5,864,021	$ 18,419,030	$ 12,449,387
Future production costs	(3,259,376)	(2,467,626)	(2,074,525)	(1,597,747)	(5,333,901)	(4,065,373)
Future development costs [1]	(1,978,527)	(1,828,635)	(953,024)	(824,991)	(2,931,551)	(2,653,627)
Future income taxes	(810,870)	(102,932)	(901,361)	(477,746)	(1,712,231)	(580,678)
Future net cash flows [2]	4,167,427	2,186,172	4,273,921	2,963,538	8,441,348	5,149,710
Deduct: 10% annual discount factor	(1,269,964)	(632,248)	(1,949,809)	(1,315,108)	(3,219,773)	(1,947,356)
Standardized measure [2]	$ 2,897,463	$ 1,553,924	$ 2,324,112	$ 1,648,430	$ 5,221,575	$ 3,202,354

(1) Our estimated future costs to settle asset retirement obligations includes both: (i) estimated costs associated with future undrilled proved locations, and (ii) estimated costs associated with producing reserves. These costs are included in the "Future development costs" line.
(2) The data in the table may not add due to rounding.

Reconciliation of Changes in Standardized Measure of Future Net Cash Flows Discounted at 10% per Year Relating to Net Proved Petroleum and Natural Gas Reserves

As at December 31, 2022 (thousands of Canadian dollars)		Canada	United States	Total [1]
Balance, beginning of year	$	1,553,924	$ 1,648,430	$ 3,202,354
Sales, net of production costs		(1,131,785)	(582,176)	(1,713,961)
Net change in prices and production costs related to future production		1,933,064	1,337,782	3,270,846
Changes in previously estimated future development costs incurred during the period		(444,451)	(277,658)	(722,109)
Development costs incurred during the period		374,443	140,740	515,183
Extensions, discoveries and improved recovery, net of related costs		462,066	26,732	488,798
Revisions of previous quantity estimates		493,498	73,356	566,854
Sales of reserves in place		(22,955)	—	(22,955)
Purchases of reserves in place		—	—	—
Accretion of discount		161,174	183,719	344,893
Net change in income taxes		(481,515)	(226,813)	(708,328)
Balance, end of year [1]	$	2,897,463	$ 2,324,112	$ 5,221,575

As at December 31, 2021 (thousands of Canadian dollars)		Canada	United States	Total [1]
Balance, beginning of year	$	293,543	$ 708,701	$ 1,002,243
Sales, net of production costs		(663,484)	(436,864)	(1,100,348)
Net change in prices and production costs related to future production		992,488	1,166,873	2,159,360
Changes in previously estimated future development costs incurred during the period		(284,411)	(42,131)	(326,542)
Development costs incurred during the period		204,912	105,093	310,005
Extensions, discoveries and improved recovery, net of related costs		497,990	77,229	575,219
Revisions of previous quantity estimates		542,259	183,285	725,544
Sales of reserves in place		(1,553)	(429)	(1,982)
Purchases of reserves in place		90	—	90
Accretion of discount		29,354	71,450	100,804
Net change in income taxes		(57,264)	(184,776)	(242,040)
Balance, end of year [1]	$	1,553,924	$ 1,648,430	$ 3,202,354

(1) The data in the table may not add due to rounding.

Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

As at December 31, 2022 (thousands of Canadian dollars)		Canada	United States	Total
Proved properties	$	6,698,047	$ 5,344,169	$ 12,042,216
Unproved properties		85,981	82,703	168,684
Total capital costs		6,784,028	5,426,872	12,210,900
Accumulated depletion and impairment		(4,179,986)	(3,241,464)	(7,421,450)
Net capitalized costs	$	2,604,042	$ 2,185,408	$ 4,789,450

As at December 31, 2021 (thousands of Canadian dollars)		Canada	United States	Total
Proved properties	$	6,713,666	$ 4,919,851	$ 11,633,517
Unproved properties		88,406	84,418	172,824
Total capital costs		6,802,072	5,004,269	11,806,341
Accumulated depletion and impairment		(4,257,833)	(2,911,313)	(7,169,146)
Net capitalized costs	$	2,544,239	$ 2,092,956	$ 4,637,195

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2022

Costs Incurred in Petroleum and Natural Gas Property Acquisition, Exploration and Development Activities

As at December 31, 2022 (thousands of Canadian dollars)		Canada	United States	Total
Property acquisition costs				
Proved properties	$	551	$ —	$ 551
Unproved properties		801	—	801
Development costs [1]		374,443	140,740	515,183
Exploration costs [2]		6,359	—	6,359
Total	$	382,154	$ 140,740	$ 522,894

As at December 31, 2021 (thousands of Canadian dollars)		Canada	United States	Total
Property acquisition costs				
Proved properties	$	60	$ —	$ 60
Unproved properties		1,497	—	1,497
Development costs [1]		204,912	105,093	310,005
Exploration costs [2]		3,298	—	3,298
Total	$	209,767	$ 105,093	$ 314,860

(1) Development and facilities capital expenditures.
(2) Cost of geological and geophysical capital expenditures and drilling costs for exploratory wells.

Results of Operations for Producing Activities

For year ended December 31, 2022 (thousands of Canadian dollars except per boe amounts)		Canada	United States	Total
Petroleum and natural gas revenues, net of royalties	$	1,649,133	$ 676,948	$ 2,326,081
Less:				
Operating costs, production and mineral taxes		327,894	94,772	422,666
Transportation and blending expense		238,015	—	238,015
Exploration and evaluation		30,239	—	30,239
Depletion and impairment reversal		141,542	171,747	313,289
Operating income		911,443	410,429	1,321,872
Income tax expense		—	—	3,594
Results of operations [1]	$	911,443	$ 410,429	$ 1,318,278

For year ended December 31, 2021 (thousands of Canadian dollars except per boe amounts)		Canada	United States	Total
Petroleum and natural gas revenues, net of royalties	$	1,006,831	$ 522,208	$ 1,529,039
Less:				
Operating costs, production and mineral taxes		257,658	85,344	343,002
Transportation and blending expense		117,950	—	117,950
Exploration and evaluation		15,212	—	15,212
Depletion and impairment reversal		(796,865)	(286,608)	(1,083,473)
Operating income		1,412,876	723,472	2,136,348
Income tax expense		—	—	1,272
Results of operations [1]	$	1,412,876	$ 723,472	$ 2,135,076

(1) Excludes corporate overhead and interest costs.