BAYTEX

ENERGY CORP.

ANNUAL INFORMATION FORM

2018

MARCH 12, 2019

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APPENDICES:

SELECTED TERMS

Capitalized terms in this Annual Information Form 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.

OPEC means the Organization of the Petroleum Exporting Countries.

Operating Entities means our subsidiaries that are actively involved in the acquisition, production, processing, transportation and marketing of crude oil, natural gas liquids and natural gas, being Baytex Energy, Baytex Partnership and Baytex USA, each a direct or indirect wholly-owned subsidiary of us.

Raging River means Raging River Exploration Inc.

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.

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

Securities and Other Terms

2021 Debentures means the 6.75% series B senior unsecured debentures due February 17, 2021 issued by Baytex pursuant to Debt Indenture #1 of which US$150 million was outstanding as at March 1, 2019.

2021 Notes means the 5.125% senior unsecured notes due June 1, 2021 issued by Baytex pursuant to Debt Indenture #2 of which US$400 million was outstanding as at March 1, 2019.

2022 Debentures means the 6.625% series C senior unsecured debentures due July 19, 2022 issued by Baytex pursuant to Debt Indenture #1 of which $300 million was outstanding as at March 1, 2019.

2024 Notes means the 5.625% senior unsecured notes due June 1, 2024 issued by Baytex pursuant to Debt Indenture #2 of which US$400 million was outstanding as at March 1, 2019.

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

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

Common Shares means the common shares of Baytex.

Credit Facilities means our Revolving Credit Facilities and our Term Loan.

CSS means cyclic steam stimulation.

Debt Indenture #1 means the amended and restated trust indenture among Baytex, as issuer, certain of its subsidiaries, as guarantors, and Valiant Trust Company, as indenture trustee, dated January 1, 2011, as supplemented by supplemental indentures dated February 17, 2011, February 18, 2011, July 19, 2012, December 19, 2012, June 4, 2014, June 11, 2014, July 25, 2014, March 6, 2015, December 15, 2017, July 10, 2018 and August 22, 2018.

Debt Indenture #2 means the indenture among Baytex, as issuer, certain of its subsidiaries, as guarantors, and Computershare Trust Company, N.A., as indenture trustee, dated June 6, 2014, as supplemented by supplemental indentures dated June 11, 2014, July 25, 2014, December 15, 2017, July 10, 2018 and August 22, 2018.

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

Revolving Credit Facilities means our US$575 million secured covenant-based credit facilities with a syndicate of financial institutions.

SAGD means steam-assisted gravity drainage.

Senior Notes means, collectively, the 2021 Debentures, the 2021 Notes, the 2022 Debentures and the 2024 Notes.

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

Term Loan means our $300 million secured term loan with a syndicate of financial institutions.

Independent Engineering

Baytex Reserves Report means the: (i) report of Sproule dated February 12, 2019 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Corp. in Canada Excluding Ferrybank Duvernay Property (As of December 31, 2018)*"; (ii) the report of Ryder Scott dated February 7, 2019 entitled "*Baytex Energy Corp. Estimated Future Reserves and Income Attributable to Certain Leasehold Interests NI 51-101 Forecast Economic Parameters Canadian Currency as of December 31, 2018*"; and (iii) the report of GLJ dated February 8, 2019 entitled "*Baytex Energy Corp. Reserves Assessment and Evaluation of Canadian Oil and Gas Properties Corporate Summary Effective December 31, 2018*".

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.

GLJ means GLJ Petroleum 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.

Ryder Scott means Ryder Scott Company, L.P., independent petroleum consultants.

Sproule means Sproule Associates Limited, independent petroleum consultants.

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
LLS	Louisiana Light Sweet
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	0.405
Hectares	Acres	2.471

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101. Unless otherwise indicated, references in this Annual Information Form to "$" or "dollars" are to Canadian dollars and references to "US$" are to United States dollars. All financial information contained in this Annual Information Form has been presented in Canadian dollars in accordance with Canadian GAAP. All operational information contained in this Annual Information Form 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 Annual Information Form 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 Annual Information Form speak only as of the date hereof and are expressly qualified by this cautionary statement.

Specifically, this Annual Information Form contains forward-looking statements relating to, but not limited to: our business strategies, plans and objectives; our 2019 capital budget; our goal of building value through internal property development and selective acquisitions; our plan to release a sustainability report in 2019; development plans for our properties; undeveloped lease expiries; the payment of cash income taxes; our working interest production volume for 2019 based on the future net revenue disclosed in our reserves; 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; the impact of existing and proposed governmental and environmental regulation; our dividend policy; and our assessment of our tax filing position for the years 2011 through 2015.

In addition, there are forward-looking statements in this Annual Information Form 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 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; 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; availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. Readers should also carefully consider the matters discussed under the heading "*Risk Factors*" in this Annual Information Form.

The above summary of assumptions and risks related to forward-looking statements in this Annual Information Form 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 Annual Information Form are expressly qualified by this cautionary statement.

New York Stock Exchange

As a Canadian foreign private issuer listed on the New York Stock Exchange (the "**NYSE**"), we are not required to comply with most of the NYSE's corporate governance rules and listing standards and instead may comply with domestic corporate governance requirements. The NYSE requires that we disclose any significant ways in which our corporate governance practices differ from those followed by U.S. domestic issuers. We have reviewed the NYSE corporate governance and listing standards applicable to U.S. domestic issuers and confirm that our corporate governance practices do not differ from such standards in any significant way.

Access to Documents

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

CORPORATE STRUCTURE

General

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

Our head and principal office is located at Suite 2800, Centennial Place, East Tower, 520 – 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3. Our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, Canada, T2P 1G1.

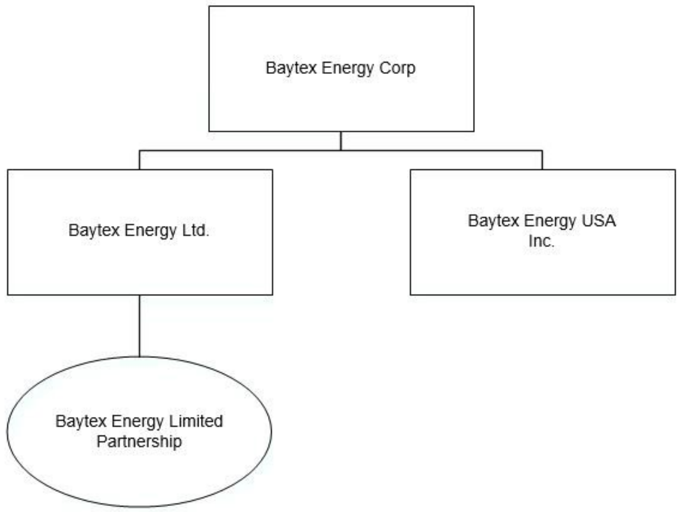
Inter-Corporate Relationships

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 and 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

2016

In 2016 we managed our business through a period of volatile and challenging commodity markets. The price for WTI averaged US $34.45/bbl in Q1 and averaged US $43.32/bbl on the year.

On March 3, in response to low commodity prices, we announced a reduced 2016 capital budget of $225-$265 million and the shut-in of 7,500 bbl/d of low or negative margin heavy oil production.

On March 31, we made significant amendments to our Credit Facilities. The amendments included reducing our Credit Facilities to US$575 million, granting our bank lending syndicate first priority security with respect to our assets and restructuring our financial covenants.

In July, we realized net proceeds of approximately $54.2 million from the disposition of our operated assets in Texas that had associated production of approximately 1,000 boe/d.

On November 22, we entered into an asset acquisition agreement to acquire heavy oil assets in the Peace River area for approximately $65 million. The lands were adjacent to our existing Peace River lands, added approximately 3,000 boe/d of production and more than doubled our land base in the area. The acquisition was financed through a concurrently announced bought deal financing, pursuant to which we issued 21,907,500 Common Shares at a price of $5.25 per Common Share for aggregate gross proceeds of approximately $115 million. The financing closed on December 12.

Our production averaged 65,509 boe/d for the year, a decline from 2015, due to reduced capital spending, our Texas disposition and shut-in production.

On December 12, we announced a 2017 capital budget range of $300-$350 million.

2017

In 2017 we saw a recovery in oil prices compared to 2016, as the price for WTI averaged $50.95/bbl.

On January 20, we closed the previously announced acquisition of heavy oil assets in the Peace River area.

On May 4, Edward D. LaFehr was appointed Chief Executive Officer, succeeding James Bowzer.

Our production averaged 70,242 boe/d, an increase from 2016, due to strong well performance, the reactivation of shut-in production and contributions from the acquired Peace River assets.

On December 7, we announced a 2018 capital budget range of $325-$375 million.

2018

In 2018 commodity prices improved relative to 2017 and 2016, but remained volatile. The price for WTI increased from Q1 through to Q3 and then dropped in Q4 to average US $64.77 for the year. The decrease in WTI during Q4 coincided with a large increase in differentials for Canadian crude oil, which impacted our Canadian operations.

On June 18, Baytex and Raging River announced a strategic combination. The merger closed on August 22 and was effected by way of a plan of arrangement under the ABCA, whereby holders of Raging River common shares received, directly or indirectly, 1.36 common shares of Baytex for each Raging River share held. Upon closing of the strategic combination, holders of Baytex shares held 43% and holders of Raging River shares held 57% of the issued and outstanding shares of the combined company.

The transaction added approximately 23,000 boe/d of production from the Viking play in Saskatchewan and Alberta and 284,000 net acres of land in the emerging East Duvernay Shale play in Alberta. At closing, a combined leadership team from both companies was appointed that included Neil J. Roszell as Chairman of the Board and Edward D. LaFehr as President and Chief Executive Officer.

Concurrent with closing, we announced an updated 2018 capital budget range of $450-$500 million and assumed the $300 million term credit facility due June 2020 from Raging River that is secured by the assets of Raging River.

Our production averaged 80,458 boe/d for the year and 98,890 boe/d in Q4, an increase from 2017, due to continued strong well performance and contributions from the Raging River combination.

On December 17, we announced a 2019 capital budget range of $550-$650 million.

Significant Acquisitions

Our merger with Raging River was a significant acquisition for which disclosure was required under Part 8 of NI 51-102. A summary of the transaction is provided above under "*Development of our Business*" and a Form 51-102F4 in respect of this transaction was filed on SEDAR on September 24, 2018.

DESCRIPTION OF OUR BUSINESS

Overview

The Corporation is an oil and gas exploration and production company whose assets are located in western Canada (Alberta and Saskatchewan) and the United States (Texas). For each of our principal assets we have established teams with a full complement of technical professionals (engineers, geoscientists and land professionals). This comprehensive technical approach is intended to result in a thorough identification and evaluation of exploration, development and acquisition opportunities and cost-efficient execution of those opportunities.

Throughout our history we have endeavoured to add value through internal property development and selective acquisitions. We are focused on per-share growth in order to deliver shareholder returns.

Competitive Conditions

Baytex is a member of the oil and natural gas industry, which is highly competitive at all levels. Baytex competes with other companies for all of its business inputs, including exploitation and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. We believe our competitive position is, on the whole, equivalent to that of other oil and natural gas producers of a similar size and production profile. See *Industry Conditions* and *Risk Factors.*

Reorganizations

On July 15, 2018 we dissolved our general partnership, Baytex Energy Partnership, which had previously held a beneficial interest in the majority of our producing properties in Canada. The beneficial interest is now held by Baytex Energy. In addition, on August 22, 2018 in conjunction with the Raging River merger, all of the oil and gas properties of Raging River were transferred to the newly formed Baytex Partnership.

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.

We published our third biennial Corporate Responsibility Report in September 2017, detailing our efforts and performance in environmental management, health and safety, leadership culture, community investment, stakeholder engagement and corporate governance. This report can also be viewed on our website at www.baytexenergy.com. In addition, Baytex was recognized by Corporate Knights as one of the Future 40 Responsible Corporate Leaders in Canada for 2018. We expect to publish our fourth Corporate Responsibility Report in 2019.

See *Industry Conditions* and *Risk Factors.*

Seasonal Factors

The level of activity in the oil and gas industry is dependent on access to areas where operations are to be conducted. In Canada, seasonal weather variations, including 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 and heavy rainfall 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 in the remainder of 2019 by the renegotiation or termination of contracts.

Personnel

As at December 31, 2018, we had 162 employees in our head office and 80 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, 2018. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2018 and production information represents average working interest production for the year ended December 31, 2018.

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 78,214 (19,933 net) acres, comprised of four areas of mutual interest (Sugarloaf, Longhorn, Ipanema and Excelsior), together with field infrastructure and related assets. These assets are operated by Marathon Oil EF LLC, a wholly-owned subsidiary of Marathon Oil Corporation (NYSE: MRO), pursuant to the terms of industry-standard joint operating agreements.

During 2018, production from the Eagle Ford assets averaged approximately 37,076 boe/d, comprised of 28,851 bbl/d of light oil and NGL and 49,349 Mcf/d of shale gas. During this period, Baytex participated in the completion of 119 (27.1 net) wells in the Sugarkane area, resulting in 63 (12.1 net) oil wells and 56 (15.0 net) natural gas wells. There are no undeveloped lands associated with the Eagle Ford assets.

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 the combination with Raging River and produce light oil from the Viking formation. In the fourth quarter of 2018, the Viking assets produced 24,603 boe/d, comprised of 22,046 bbl/d of light oil and NGL and 10,425 Mcf/d of natural gas. These assets provide a predictable production profile and numerous low risk drilling opportunities. Since acquisition on August 22, 2018, Baytex has completed 121 (83.0 net) wells, resulting in 120 (82.0 net) oil wells and 1 (0.9 net) abandoned well. The undeveloped land base associated with the Viking assets consisted of 255,918 net acres at year-end 2018.

Peace River - Alberta

In the Peace River area of northwest Alberta we produce heavy gravity crude oil, bitumen, and natural gas mainly from the Bluesky formation. During 2018, production from the area averaged approximately 16,997 boe/d, comprised of 15,118 bbl/d of heavy oil and 10,809 Mcf/d of natural gas. In 2018, Baytex drilled 12 (12.0 net) horizontal multi-lateral wells and one (1.0 net) service well in this area. Baytex held approximately 407,923 net undeveloped acres in this area at year-end 2018.

Lloydminster - Alberta and Saskatchewan

Our Lloydminster assets consist of several geographically dispersed heavy oil operations that include primary and thermal production. In some cases, Baytex's heavy oil reservoirs are waterflooded. In 2018, production averaged approximately 10,653 boe/d, which was comprised of 9,824 bbl/d of heavy oil, 700 bbl/d of bitumen, and 602 Mcf/d of natural gas. During 2018, Baytex drilled 94 (69.5 net) wells, resulting in 85 (60.9 net) oil wells and 8 (8.0 net) stratigraphic and service wells in the area. We held approximately 164,459 net undeveloped acres in this area at year-end 2018.

Duvernay - Alberta

On August 22, 2018, as a result of the the merger with Raging River, Baytex acquired a land position in the emerging East Duvernay shale basin in central Alberta. In the fourth quarter of 2018, the Duvernay assets produced 1,432 boe/d, comprised of 1,231 bbl/d of light oil and NGL and 1,200 Mcf/d of natural gas. Since acquisition on August 22, 2018, Baytex completed four (4.0 net) wells, resulting in four (4.0 net) oil wells. As at December 31, 2018, our net undeveloped lands totaled approximately 301,760 net acres.

Average Production

The following table indicates our average daily production from our principal properties for the year ended December 31, 2018.

	Heavy Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Oil (bbl/d)	Tight Oil (bbl/d)	NGL (bbl/d)	Shale Gas (Mcf/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy								
Peace River	15,118	—	3	—	76	—	10,809	16,997
Lloydminster	9,824	700	28	—	—	—	602	10,653
Total	24,942	700	31	—	76	—	11,411	27,650
Canada - Light								
Viking	312	—	7,794	—	23	—	3,635	8,735
Duvernay	—	—	—	289	84	—	336	430
Remaining properties	—	—	845	—	1,016	—	28,240	6,567
Total	312	—	8,639	289	1,123	—	32,211	15,732
United States								
Eagle Ford	—	—	—	20,305	8,546	49,349	—	37,076
Grand Total	25,254	700	8,670	20,594	9,745	49,349	43,622	80,458

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2018.

($000s)	Canada	United States	Total
Property acquisition costs			
Proved properties	1,507,997	—	1,507,997
Unproved properties	98,372	—	98,372
Property disposition	(2,519)	—	(2,519)
Total Property acquisition costs, net	1,603,850	—	1,603,850
Development Costs (1)	291,550	193,604	485,154
Exploration Costs (2)	10,567	—	10,567
Total	1,905,967	193,604	2,099,571

Notes:

(1) Development and facilities expenditures.

(2) Cost of land, geological and geophysical capital expenditures and drilling costs for 2018 exploratory wells drilled.

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, 2018.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,171	905.4	1,334	855.2	341	269.7	520	386.3
Saskatchewan	3,204	2,874.3	1,827	1,725	111	74.2	214	178.7
Texas	680	152.5	20	3.3	405	110.6	47	12.7
Total	5,055	3,932.2	3,181	2,583.5	857	454.5	781	577.7

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2018.

	Undeveloped Acres	
	Gross	Net
Alberta	1,054,743	964,579
Saskatchewan	369,366	329,641
Total	1,424,109	1,294,220

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2018. 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, 2018 to be approximately $164.6 million, as compared to $75.9 million as at December 31, 2017. This internal evaluation generally represents the estimated replacement cost of our undeveloped land and excludes approximately 98,952 net acres of our undeveloped land that we expect to expire on or before December 31, 2019. 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.

Tax Horizon

Baytex does not expect to pay any material cash income taxes prior to 2022. 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 16 of our audited consolidated financial statements for the year ended December 31, 2018 and the information under the headings "*Income Taxes*" and "*Tax Pools*" in our MD&A for the year ended December 31, 2018.

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, 2018.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	285	172.0	285	172.0
Natural Gas	—	—	58	17.0	58	17.0
Stratigraphic	8	8.0	—	—	8	8.0
Service	1	1.0	—	—	1	1.0
Dry	—	—	2	1.6	2	1.6
Total	9	9.0	345	190.6	354	199.6

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ending December 31, 2019, 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 Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Oil (bbl/d)	Tight Oil (bbl/d)	NGL (bbl/d)	Shale Gas (Mcf/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
CANADA								
Total Proved	21,683	1,656	19,791	609	929	894	37,321	51,036
Total Proved plus Probable	23,906	1,754	22,533	1,224	1,157	1,516	40,562	57,587
UNITED STATES								
Total Proved	—	—	—	9,312	16,127	32,479	11,682	32,799
Total Proved plus Probable	—	—	—	10,383	17,136	34,328	13,134	35,429
TOTAL								
Total Proved	21,683	1,656	19,791	9,920	17,056	33,373	49,002	83,835
Total Proved plus Probable	23,906	1,754	22,533	11,607	18,293	35,844	53,696	93,016

The two properties that account for 20% or more of the estimated 2019 production volumes are the Eagle Ford and the Viking. Estimated 2019 production volumes for the Eagle Ford is 32,799 boe/d on a total proved basis and 35,429 boe/d on a total proved plus probable basis. Estimated 2019 production volumes for the Viking is 21,371 boe/d on a total proved basis and 24,266 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, 2018	Sep. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2018
Average Sales Volume (1)					
Heavy Oil (bbl/d)	25,399	26,438	24,985	24,167	25,254
Bitumen (bbl/d)	940	598	559	701	700

	Three Months Ended				Year Ended
	Dec. 31, 2018	Sep. 30, 2018	June 30, 2018	Mar. 31, 2018	Dec. 31, 2018
Light Oil (bbl/d)	22,978	9,663	792	810	8,625
NGL (bbl/d)	10,327	10,076	9,419	9,143	9,745
Tight Oil (bbl/d)	22,009	20,068	20,308	20,157	20,639
Shale Gas (Mcf/d)	49,742	50,287	48,955	48,388	49,349
Natural Gas (Mcf/d)	53,682	43,127	38,650	38,873	43,622
Total (boe/d)	98,890	82,412	70,664	69,522	80,458
Average Net Production Prices Received					
Heavy Oil ($/bbl)	13.67	48.15	49.77	33.41	36.33
Bitumen ($/bbl)	13.10	48.13	46.69	30.56	31.64
Light Oil ($/bbl)	40.56	76.38	71.59	62.54	51.89
NGL ($/bbl)	29.96	37.38	31.37	26.17	31.36
Tight Oil ($/bbl)	81.33	93.19	87.34	79.87	85.36
Shale Gas ($/Mcf)	5.35	3.90	3.73	3.78	4.20
Natural Gas ($/Mcf)	1.67	1.21	1.07	1.92	1.48
Total ($/boe)	37.89	55.03	51.22	42.96	46.31
Royalties Paid					
Heavy Oil ($/bbl)	3.33	8.08	7.45	4.71	5.92
Bitumen ($/bbl)	3.65	0.92	2.34	21.59	7.24
Light Oil and NGL ($/bbl) (2)	5.19	8.38	7.92	5.49	6.47
Tight Oil ($/bbl)	23.95	28.09	26.09	23.91	25.48
Shale Gas ($/Mcf)	1.49	1.09	1.01	1.07	1.16
Natural Gas ($/Mcf)	0.09	0.04	0.02	0.09	0.06
Total ($/boe)	8.77	12.13	12.01	10.36	10.68
Operating Expenses (3)					
Heavy Oil ($/bbl)	15.48	13.68	15.09	15.40	14.89
Bitumen ($/bbl)	24.01	37.64	53.79	34.64	35.50
Light Oil and NGL ($/bbl) (2)	10.17	9.33	8.10	7.59	9.31
Tight Oil ($/bbl)	6.69	6.85	7.05	6.38	6.73
Shale Gas ($/Mcf)	1.09	1.12	1.16	1.05	1.11
Natural Gas ($/Mcf)	2.00	1.91	2.10	2.07	2.02
Total ($/boe)	10.76	10.25	10.91	10.53	10.61
Transportation Expenses					
Heavy Oil ($/bbl)	2.83	2.89	3.03	3.33	3.01
Bitumen ($/bbl)	1.38	1.80	1.53	1.53	1.54
Light Oil and NGL ($/bbl) (2)	0.94	0.78	0.15	0.24	0.69
Tight Oil ($/bbl)	—	—	—	—	—
Shale Gas ($/Mcf)	—	—	—	—	—
Natural Gas ($/Mcf)	0.25	0.24	0.21	0.28	0.24
Total ($/boe)	1.21	1.26	1.22	1.36	1.26

	Three Months Ended				Year Ended
	Dec. 31, 2018	Sep. 30, 2018	June 30, 2018	Mar. 31, 2018	Dec. 31, 2018
Netback Received (4)					
Heavy Oil ($/bbl)	(7.97)	23.50	24.19	9.97	12.50
Bitumen ($/bbl)	(15.94)	7.77	(10.97)	(27.20)	(12.63)
Light Oil and NGL ($/bbl) (2)	20.96	37.99	18.32	15.81	24.52
Tight Oil ($/bbl)	50.62	58.25	54.19	49.58	53.13
Shale Gas ($/Mcf)	2.77	1.70	1.56	1.66	1.93
Natural Gas ($/Mcf)	(0.67)	(0.99)	(1.25)	(0.51)	(0.85)
Total ($/boe)	17.15	31.39	27.08	20.71	23.76
Financial Derivatives loss ($/boe)	(0.34)	(4.07)	(4.57)	(1.57)	(2.49)
Netback Received after hedging ($/boe)	16.81	27.32	22.51	19.14	21.27

Notes:

(1) Before deduction of royalties.

(2) All NGL volumes are grouped with Canadian light oil for royalties paid and operating expenses for reporting purposes.

(3) 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.

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

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 oil volumes, this includes a number of rail commitments. In the United States, production from our assets is marketed on behalf of all the working interest owners by the operator.

The Corporation also has a hedging 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 December 31, 2018, see Note 19 to our audited consolidated financial statements for the year ended December 31, 2018. 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, 2018. The effective date of the Baytex Reserves Report is December 31, 2018 and the preparation date of the statement is February 12, 2019 in the case of Sproule, February 7, 2019 in the case of Ryder Scott and February 8, 2019 in the case of GLJ. The Baytex Reserves Report was prepared using Sproule's December 31, 2018 forecast price and cost assumptions.

Disclosure of Reserves Data

The tables below are a combined summary as at December 31, 2018 of our proved and probable heavy 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 (in Alberta and Saskatchewan) and the United States (in 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, 2018
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)
PROVED:						
Developed Producing	740	652	30,987	29,089	24,922	20,092
Developed Non-Producing	—	—	263	256	1,161	1,006
Undeveloped	1,360	1,191	40,296	37,584	23,530	20,668
TOTAL PROVED	2,099	1,843	71,545	66,929	49,613	41,766
PROBABLE	3,254	2,730	20,941	19,352	42,687	35,726
TOTAL PROVED PLUS PROBABLE	5,353	4,572	92,487	86,281	92,301	77,492

CANADA

RESERVES CATEGORY	BITUMEN Gross (Mbbl)	BITUMEN Net (Mbbl)	SHALE GAS Gross (MMcf)	SHALE GAS Net (MMcf)	CONVENTIONAL NATURAL GAS (1) Gross (MMcf)	CONVENTIONAL NATURAL GAS (1) Net (MMcf)
PROVED:						
Developed Producing	1,934	1,478	1,432	1,310	55,986	50,308
Developed Non-Producing	7,746	7,008	—	—	1,943	1,533
Undeveloped	3,126	2,712	1,890	1,724	52,628	47,699
TOTAL PROVED	12,805	11,198	3,321	3,034	110,557	99,540
PROBABLE	55,545	43,284	5,506	4,968	98,032	87,375
TOTAL PROVED PLUS PROBABLE	68,350	54,482	8,828	8,002	208,589	186,915

CANADA

RESERVES CATEGORY	**NATURAL GAS LIQUIDS** (2) Gross (Mbbl)	Net (Mbbl)	**TOTAL RESERVES** Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	1,401	1,070	69,553	60,983
Developed Non-Producing	3	3	9,497	8,528
Undeveloped	1,628	1,340	79,026	71,732
TOTAL PROVED	3,032	2,412	158,075	141,243
PROBABLE	3,848	3,013	143,532	119,495
TOTAL PROVED PLUS PROBABLE	6,880	5,425	301,607	260,738

UNITED STATES

RESERVES CATEGORY	**TIGHT OIL** Gross (Mbbl)	Net (Mbbl)	**SHALE GAS** Gross (MMcf)	Net (MMcf)	**CONVENTIONAL NATURAL GAS** (1) Gross (MMcf)	Net (MMcf)
PROVED:						
Developed Producing	18,348	13,445	66,901	49,572	24,993	18,357
Developed Non-Producing	38	28	566	417	49	36
Undeveloped	32,334	23,700	80,367	59,166	32,506	23,803
TOTAL PROVED	50,720	37,174	147,835	109,155	57,548	42,197
PROBABLE	18,625	13,680	66,043	48,502	24,652	18,147
TOTAL PROVED PLUS PROBABLE	69,345	50,854	213,878	157,657	82,200	60,344

UNITED STATES

RESERVES CATEGORY	**NATURAL GAS LIQUIDS** (2) Gross (Mbbl)	Net (Mbbl)	**TOTAL RESERVES** Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	31,512	23,309	65,176	48,076
Developed Non-Producing	214	158	354	261
Undeveloped	39,856	29,312	91,002	66,841
TOTAL PROVED	71,582	52,779	156,532	115,178
PROBABLE	34,625	25,441	68,366	50,229
TOTAL PROVED PLUS PROBABLE	106,207	78,220	224,898	165,407

TOTAL

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)
PROVED:						
Developed Producing	19,088	14,097	30,987	29,089	24,922	20,092
Developed Non-Producing	38	28	263	256	1,161	1,006
Undeveloped	33,693	24,891	40,296	37,584	23,530	20,668
TOTAL PROVED	52,819	39,016	71,545	66,929	49,613	41,766
PROBABLE	21,879	16,410	20,941	19,352	42,687	35,726
TOTAL PROVED PLUS PROBABLE	74,698	55,426	92,487	86,281	92,301	77,492

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	1,934	1,478	68,333	50,882	80,980	68,665
Developed Non-Producing	7,746	7,008	566	417	1,991	1,569
Undeveloped	3,126	2,712	82,257	60,890	85,133	71,502
TOTAL PROVED	12,805	11,198	151,156	112,188	168,104	141,736
PROBABLE	55,545	43,284	71,550	53,471	122,685	105,523
TOTAL PROVED PLUS PROBABLE	68,350	54,482	222,706	165,659	290,789	247,259

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	32,912	24,379	134,729	109,059
Developed Non-Producing	217	160	9,851	8,789
Undeveloped	41,484	30,652	170,028	138,572
TOTAL PROVED	74,614	55,191	314,607	256,421
PROBABLE	38,473	28,454	211,898	169,724
TOTAL PROVED PLUS PROBABLE	113,087	83,645	526,505	426,145

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, 2018
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	1,792,884	1,544,771	1,355,997	1,212,741	1,101,425	22.24
Developed Non-Producing	244,486	172,472	125,171	93,194	70,965	14.68
Undeveloped	1,841,321	1,279,571	907,327	654,251	476,320	12.65
TOTAL PROVED	3,878,692	2,996,814	2,388,494	1,960,186	1,648,709	16.91
PROBABLE	3,862,671	2,304,632	1,538,566	1,108,674	841,887	12.88
TOTAL PROVED PLUS PROBABLE	7,741,363	5,301,446	3,927,060	3,068,859	2,490,597	15.06

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	1,627,506	1,192,348	961,733	820,072	723,542	20.00
Developed Non-Producing	8,652	6,491	5,164	4,286	3,667	19.77
Undeveloped	1,667,167	1,099,049	759,576	542,510	396,760	11.36
TOTAL PROVED	3,303,324	2,297,888	1,726,473	1,366,868	1,123,969	14.99
PROBABLE	1,750,388	901,795	531,484	343,816	238,512	10.58
TOTAL PROVED PLUS PROBABLE	5,053,712	3,199,683	2,257,957	1,710,684	1,362,481	13.65

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	3,420,390	2,737,119	2,317,729	2,032,813	1,824,967	21.25
Developed Non-Producing	253,138	178,963	130,335	97,480	74,631	14.83
Undeveloped	3,508,488	2,378,620	1,666,903	1,196,760	873,080	12.03
TOTAL PROVED	7,182,016	5,294,702	4,114,967	3,327,054	2,772,678	16.05
PROBABLE	5,613,059	3,206,427	2,070,050	1,452,489	1,080,399	12.20
TOTAL PROVED PLUS PROBABLE	12,795,075	8,501,129	6,185,017	4,779,543	3,853,078	14.51

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/year)[1] 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,792,884	1,544,771	1,355,997	1,212,741	1,101,425
Developed Non-Producing	244,486	172,472	125,171	93,194	70,965
Undeveloped	1,382,055	955,976	668,621	471,850	333,045
TOTAL PROVED	3,419,426	2,673,219	2,149,789	1,777,786	1,505,435
PROBABLE	2,928,086	1,736,475	1,150,353	822,116	619,172
TOTAL PROVED PLUS PROBABLE	6,347,512	4,409,694	3,300,142	2,599,902	2,124,606

UNITED STATES

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/year)[1] 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,574,045	1,171,169	951,451	813,939	719,204
Developed Non-Producing	8,652	6,491	5,164	4,286	3,667
Undeveloped	1,355,393	903,907	630,693	453,881	333,812
TOTAL PROVED	2,938,090	2,081,566	1,587,308	1,272,106	1,056,683
PROBABLE	1,371,775	706,471	417,210	271,308	189,846
TOTAL PROVED PLUS PROBABLE	4,309,865	2,788,037	2,004,519	1,543,414	1,246,529

TOTAL

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/year)[1] 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	3,366,929	2,715,940	2,307,447	2,026,680	1,820,629
Developed Non-Producing	253,138	178,963	130,335	97,480	74,631
Undeveloped	2,737,449	1,859,883	1,299,315	925,731	666,857
TOTAL PROVED	6,357,515	4,754,786	3,737,097	3,049,892	2,562,117
PROBABLE	4,299,862	2,442,946	1,567,564	1,093,425	809,018
TOTAL PROVED PLUS PROBABLE	10,657,377	7,197,731	5,304,661	4,143,316	3,371,135

Notes:

(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, 2018
FORECAST PRICES AND COSTS

($000s)	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	WELL ABANDONMENT COSTS[(1)]	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
TOTAL PROVED RESERVES								
Canada	10,194,257	1,103,779	3,407,196	1,448,569	356,023	3,878,692	459,266	3,419,426
United States	10,805,175	3,345,016	2,878,888	1,216,580	61,366	3,303,324	365,235	2,938,089
Total	20,999,432	4,448,795	6,286,083	2,665,148	417,389	7,182,016	824,501	6,357,515
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	19,968,777	2,808,571	6,530,862	2,459,074	428,907	7,741,363	1,393,851	6,347,512
United States	16,295,523	5,052,065	4,330,317	1,776,209	83,219	5,053,712	743,847	4,309,865
Total	36,264,299	7,860,636	10,861,179	4,235,283	512,126	12,795,075	2,137,698	10,657,377

Notes:

(1) Includes well abandonment and reclamation based on estimates by the Corporation for all reserves wells, producing and undeveloped, but does not include abandonment and surface reclamation costs for any existing facilities.

FUTURE NET REVENUE BY PRODUCT TYPE
AS OF DECEMBER 31, 2018
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE ($/boe) [(1)]
Proved	Light and Medium Crude Oil (including solution gas and associated byproducts)	1,513,974	21.14
	Heavy Crude Oil (including solution gas and associated byproducts)	573,358	12.66
	Bitumen (including solution gas and associated byproducts)	202,538	18.09
	Tight Oil (including solution gas and associated byproducts)	961,611	17.33
	Natural Gas (associated and non-associated) (including associated byproducts)	41,262	4.10
	Shale Gas (including associated byproducts)	822,224	13.10
	Total	4,114,967	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated byproducts)	2,130,068	22.92
	Heavy Crude Oil (including solution gas and associated byproducts)	1,020,362	12.13
	Bitumen (including solution gas and associated byproducts)	527,138	9.68
	Tight Oil (including solution gas and associated byproducts)	1,309,115	18.02
	Natural Gas (associated and non-associated) (including associated byproducts)	107,666	5.04
	Shale Gas (including associated byproducts)	1,090,669	11.76
	Total	6,185,017	

Notes:

(1) Unit values are based on 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, 2018[(1)]

	Oil				Natural Gas				
Year	WTI Cushing Oklahoma[(2)] ($US/bbl)	LLS Onshore 40° API[(3)] ($US/bbl)	Canada Light Sweet Crude 40° API[(4)] ($Cdn/bbl)	Western Canadian Select 20.5° API[(5)] ($Cdn/bbl)	Henry Hub[(6)] ($US/MMbtu)	AECO-C Spot[(7)] ($Cdn/MMbtu)	Operating Cost Inflation Rate[(8)] (%/Yr)	Capital Cost Inflation Rate[(8)] (%/Yr)	Exchange Rate[(9)] ($US/$Cdn)
Historical									
2014	93.00	96.75	93.99	81.06	4.28	4.50	2.0	(1.0)	0.905
2015	48.80	52.38	57.45	44.83	2.63	2.70	1.8	(18.7)	0.783
2016	43.32	44.88	52.80	38.89	2.55	2.18	1.2	(9.7)	0.755
2017	50.95	54.13	61.84	50.24	3.02	2.19	1.7	2.4	0.771
2018	64.77	69.81	68.49	52.34	3.07	1.53	2.5	4.2	0.772
Forecast[(10)]									
2019	63.00	68.40	75.27	59.47	3.00	1.95	—	—	0.770
2020	67.00	70.37	77.89	62.31	3.25	2.44	2.0	2.0	0.800
2021	70.00	71.34	82.25	67.45	3.50	3.00	2.0	2.0	0.800
2022	71.40	72.76	84.79	69.53	3.57	3.21	2.0	2.0	0.800
2023	72.83	74.22	87.39	71.66	3.64	3.30	2.0	2.0	0.800
2024	74.28	75.70	89.14	73.10	3.71	3.39	2.0	2.0	0.800
2025	75.77	77.22	90.92	74.56	3.79	3.49	2.0	2.0	0.800
2026	77.29	78.76	92.74	76.05	3.86	3.58	2.0	2.0	0.800
2027	78.83	80.34	94.60	77.57	3.94	3.68	2.0	2.0	0.800
2028	80.41	81.94	96.49	79.12	4.02	3.78	2.0	2.0	0.800
2029	82.02	83.58	98.42	80.70	4.10	3.88	2.0	2.0	0.800

Notes:

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

(2) Price used in the preparation of natural gas liquids reserves in the United States.

(3) Price used in the preparation of tight oil and condensate reserves in the United States.

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

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

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

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

(8) Inflation rates for forecasting prices and costs.

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

(10) After 2029 prices and costs escalate at 2.0% annually and the exchange rate remains 0.800.

Weighted average prices realized by us for the year ended December 31, 2018, excluding hedging activities, were $36.33/bbl for heavy oil, $31.64/bbl for bitumen, $51.89/bbl for light oil, $85.36/bbl for tight oil, $31.36/bbl for NGL, $4.20/Mcf for shale gas and $1.48/Mcf for natural gas.

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

CANADA	**HEAVY OIL**			**BITUMEN**		
	Proved (Mbbl)	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2017	46,706	39,757	86,463	13,266	55,726	68,992
Extensions	1,282	690	1,972	—	—	—
Infill Drilling	1,346	905	2,251	—	—	—
Improved Recovery	1,952	4,621	6,574	—	—	—
Technical Revisions [(1)]	4,315	(4,922)	(607)	(205)	(178)	(382)
Discoveries	2	2	4	—	—	—
Acquisitions [(2)]	3,080	1,522	4,602	—	—	—
Dispositions	(1)	(2)	(2)	—	—	—
Economic Factors	149	114	262	—	(3)	(3)
Production	(9,218)	—	(9,218)	(256)	—	(256)
December 31, 2018	49,613	42,687	92,301	12,805	55,545	68,350

CANADA	**LIGHT AND MEDIUM OIL**			**TIGHT OIL**		
	Proved (Mbbl)	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2017	1,608	1,225	2,833	—	—	—
Extensions [(2)]	—	—	—	1,515	2,645	4,160
Infill Drilling [(2)]	10,823	2,856	13,679	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [(1)]	273	(381)	(109)	—	—	—
Discoveries	—	—	—	65	15	80
Acquisitions [(2)]	61,992	17,234	79,226	625	594	1,219
Dispositions	—	—	—	—	—	—
Economic Factors	15	8	23	—	—	—
Production	(3,165)	—	(3,165)	(106)	—	(106)
December 31, 2018	71,545	20,941	92,487	2,099	3,254	5,353

CANADA	NATURAL GAS LIQUIDS [4]			SHALE GAS		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2017	2,618	3,132	5,750	—	—	—
Extensions [2]	644	1,173	1,817	2,582	4,681	7,262
Infill Drilling [2]	—	—	—	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(57)	(671)	(728)	—	—	—
Discoveries	12	3	15	73	17	90
Acquisitions [2]	349	256	605	790	809	1,599
Dispositions	—	—	—	—	—	—
Economic Factors	(96)	(45)	(141)	—	—	—
Production	(438)	—	(438)	(123)	—	(123)
December 31, 2018	3,032	3,848	6,880	3,321	5,506	8,828

CANADA	CONVENTIONAL NATURAL GAS [3]			OIL EQUIVALENT		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2017	117,819	89,963	207,782	83,834	114,834	198,667
Extensions [2]	66	185	250	3,882	5,319	9,201
Infill Drilling [2]	4,308	1,388	5,697	12,887	3,992	16,879
Improved Recovery	—	—	—	1,952	4,621	6,574
Technical Revisions [1]	(21,411)	(3,852)	(25,264)	758	(6,794)	(6,036)
Discoveries	—	—	—	92	22	114
Acquisitions [2]	28,494	11,812	40,306	70,926	21,709	92,635
Dispositions	—	—	—	(1)	(2)	(2)
Economic Factors	(2,920)	(1,463)	(4,383)	(419)	(170)	(590)
Production	(15,799)	—	(15,799)	(15,835)	—	(15,835)
December 31, 2018	110,557	98,032	208,589	158,075	143,532	301,607

UNITED STATES	TIGHT OIL			CONVENTIONAL NATURAL GAS [3]		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2017	50,296	11,390	61,686	64,018	10,761	74,778
Extensions	—	—	—	—	—	—
Infill Drilling	1,062	147	1,209	1,747	255	2,002
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	5,285	7,154	12,438	(3,507)	13,767	10,260
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(175)	(65)	(240)	(277)	(130)	(407)
Production	(5,748)	—	(5,748)	(4,433)	—	(4,433)
December 31, 2018	50,720	18,625	69,345	57,548	24,652	82,200

UNITED STATES	SHALE GAS			NATURAL GAS LIQUIDS [4]		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2017	172,855	75,686	248,541	81,947	35,830	117,777
Extensions	—	—	—	—	—	—
Infill Drilling	407	121	528	534	109	643
Improved Recovery	—	—	—	—	—	—
Technical Revisions [1]	(10,715)	(9,111)	(19,826)	(5,685)	(1,045)	(6,730)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(1,133)	(652)	(1,785)	(432)	(269)	(700)
Production	(13,579)	—	(13,579)	(4,783)	—	(4,783)
December 31, 2018	147,835	66,043	213,878	71,582	34,625	106,207

UNITED STATES	OIL EQUIVALENT		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2017	171,722	61,628	233,350
Extensions	—	—	—
Infill Drilling	1,955	319	2,274
Improved Recovery	—	—	—
Technical Revisions [1]	(2,770)	6,885	4,114
Discoveries	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	(841)	(465)	(1,306)
Production	(13,533)	—	(13,533)
December 31, 2018	156,532	68,366	224,898

TOTAL	HEAVY OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2017	46,706	39,757	86,463	13,266	55,726	68,992
Extensions	1,282	690	1,972	—	—	—
Infill Drilling	1,346	905	2,251	—	—	—
Improved Recovery	1,952	4,621	6,574	—	—	—
Technical Revisions [1]	4,315	(4,922)	(607)	(205)	(178)	(382)
Discoveries	2	2	4	—	—	—
Acquisitions [2]	3,080	1,522	4,602	—	—	—
Dispositions	(1)	(2)	(2)	—	—	—
Economic Factors	149	114	262	—	(3)	(3)
Production	(9,218)	—	(9,218)	(256)	—	(256)
December 31, 2018	49,613	42,687	92,301	12,805	55,545	68,350

TOTAL	LIGHT AND MEDIUM OIL			TIGHT OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2017	1,608	1,225	2,833	50,296	11,390	61,686
Extensions (2)	—	—	—	1,515	2,645	4,160
Infill Drilling (2)	10,823	2,856	13,679	1,062	147	1,209
Improved Recovery	—	—	—	—	—	—
Technical Revisions (1)	273	(381)	(109)	5,285	7,154	12,438
Discoveries	—	—	—	65	15	80
Acquisitions (2)	61,992	17,234	79,226	625	594	1,219
Dispositions	—	—	—	—	—	—
Economic Factors	15	8	23	(175)	(65)	(240)
Production	(3,165)	—	(3,165)	(5,854)	—	(5,854)
December 31, 2018	71,545	20,941	92,487	52,819	21,879	74,698

TOTAL	NATURAL GAS LIQUIDS (4)			SHALE GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2017	84,564	38,962	123,526	172,855	75,686	248,541
Extensions (2)	644	1,173	1,817	2,582	4,681	7,262
Infill Drilling	534	109	643	407	121	528
Improved Recovery	—	—	—	—	—	—
Technical Revisions (1)	(5,742)	(1,716)	(7,458)	(10,715)	(9,111)	(19,826)
Discoveries	12	3	15	73	17	90
Acquisitions (2)	349	256	605	790	809	1,599
Dispositions	—	—	—	—	—	—
Economic Factors	(528)	(314)	(841)	(1,133)	(652)	(1,785)
Production	(5,220)	—	(5,220)	(13,702)	—	(13,702)
December 31, 2018	74,614	38,473	113,087	151,156	71,550	222,706

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, 2017	181,837	100,724	282,560	255,556	176,461	432,017
Extensions (2)	66	185	250	3,882	5,319	9,201
Infill Drilling (2)	6,055	1,643	7,699	14,842	4,311	19,153
Improved Recovery	—	—	—	1,952	4,621	6,574
Technical Revisions (1)	(24,918)	9,915	(15,004)	(2,013)	91	(1,922)
Discoveries	—	—	—	92	22	114
Acquisitions (2)	28,494	11,812	40,306	70,926	21,709	92,635
Dispositions	—	—	—	(1)	(2)	(2)
Economic Factors	(3,197)	(1,593)	(4,790)	(1,261)	(635)	(1,896)
Production	(20,232)	—	(20,232)	(29,368)	—	(29,368)
December 31, 2018	168,104	122,685	290,789	314,607	211,898	526,505

Notes:

(1) Negative technical revisions for conventional natural gas are largely the result of adjustments to our gas conservation bookings in the Peace River area and reduced type well profiles in our Canadian conventional natural gas properties. Positive technical revisions for tight oil are the result of enhanced type well profiles on our Eagle Ford acreage, as well as the reclassification of some natural gas liquids volumes to tight oil. Negative technical revisions for shale gas and natural gas liquids are the

result of the removal of certain drilling locations on our Eagle Ford acreage as well as reclassification of shale gas volumes to solution gas.

(2) Acquisitions are principally attributable to reserves associated with the Raging River combination. For light and medium crude oil and tight oil, reserves associated with the Raging River assets are captured within acquisitions, extensions and infill drilling. Total proved reserves of 11.5 mmboe and total proved plus probable reserves of 14.6 MMboe of the infill drilling additions are associated with the Raging River Acquisition. Total proved reserves of 2.6 MMboe and total proved plus probable reserves of 7.2 MMboe of the extensions additions are associated with the Raging River combination.

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

(4) Natural gas liquids includes condensate.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule, Ryder Scott and GLJ 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 would take place over the next 28 years. We have booked 0.6 Mbbls of proved developed non-producing reserves and 42.4 Mbbls of probable undeveloped reserves to the Gemini SAGD project.

Proved Undeveloped Reserves

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

	Light and Medium Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Bitumen Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2016	—	308	4,561	30,472	1,215	18,343	—	5,428
2017	—	125	1,096	30,074	4,529	18,680	—	5,428
2018	40,127	40,296	1,640	33,694	2,646	23,530	—	3,126

	Conventional Natural Gas Gross (Mmcf)		Shale Gas Gross (Mmcf)		Natural Gas Liquids Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2016	5,038	95,264	20,050	112,899	9,817	54,539
2017	6,690	76,668	863	111,506	918	55,306
2018	17,728	85,134	1,905	82,257	600	41,484

Probable Undeveloped Reserves

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

	Light and Medium Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Bitumen Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2016	—	1,120	5,789	5,808	2,268	20,256	—	47,219
2017	—	806	2,234	8,511	12,764	29,878	—	47,137
2018	12,120	12,524	3,060	16,145	1,984	31,295	—	46,535

	Conventional Natural Gas Gross (Mmcf)		Shale Gas Gross (Mmcf)		Natural Gas Liquids Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2016	8,687	81,161	43,066	51,955	21,703	28,214
2017	7,996	86,334	6,413	68,455	1,347	35,305
2018	9,681	97,183	4,866	51,670	1,252	29,398

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 those surface leases, wells and facilities held by us which have not been included in the calculation of future net revenue as they are not associated with our reserves. The additional liability associated with these existing surface leases, wells and facilities which was not included when estimating future net revenue, inflated at 2% per year, is estimated to be $727.8 million undiscounted ($56.6 million discounted at 10 percent).

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, 2018
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
2019	302,027	361,583	129,181	144,727	431,208	506,309
2020	457,359	633,766	292,260	292,260	749,619	926,025
2021	400,568	487,702	264,263	264,263	664,831	751,965
2022	276,701	451,347	273,975	273,975	550,676	725,323
2023	10,499	216,289	240,502	241,144	251,002	457,433
Remaining	1,414	308,388	16,398	559,839	17,812	868,227
Total (undiscounted)	1,448,569	2,459,074	1,216,580	1,776,209	2,665,148	4,235,283

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 Annual Information Form 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 Annual Information Form 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, the condition of the Canadian, United States, European and Asian economies, 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 oil and heavy 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, 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 decline, the carrying value of our assets could be subject to downward revisions and our net earnings could be adversely affected.

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. Any significant change in market factors 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. A significant change may result from the conversion of most of the capacity on the Enbridge mainline from the common carrier model, which will end on July 1, 2021, where all producers have access, to a contracted service model, where only producers who sign long term transportation agreements will have access.

Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and no pipeline capacity to tidewater allowing access to world markets has been constructed. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. Although pipeline expansions are ongoing, the lack of pipeline capacity continues to affect the oil and natural gas industry in Canada and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that investment in pipelines, which would result in additional long-term take-away capacity, will be made by applicable third party pipeline providers or that any requisite applications will receive regulatory approval. 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 or derailment 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 comply with the covenants in the agreements governing our debt 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 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 secured 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.

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

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. 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 markets 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. Should a lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued which could have a dilutive effect on Shareholders. Additionally, from time to time, we may issue Common Shares or other securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

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, which 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. 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.

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

Our existing Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, 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 before June 4, 2020, 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. In addition, we are required to repay the Senior Notes at maturity. See "*Description of 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 EF LLC ("**Marathon Oil**"), a wholly-owned subsidiary of Marathon Oil Corporation (NYSE: MRO), 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, if any.

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 operation.

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; scheduling delays; trucking and fuel costs; failure to maintain quality construction standards; the cost of new technologies and supply chain disruptions, including access to skilled labour. Natural gas, electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating and other costs that are susceptible to significant fluctuation.

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced

Our future oil and natural gas reserves and production, and therefore our cash flow, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. The business of exploring for, developing or acquiring reserves is capital intensive. If external sources of capital 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.

There is no assurance we will be successful in developing additional 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 reserves life of our properties will decline, which may result in a reduction in the value of our Common Shares.

Our ability to add to our oil and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves

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 petroleum substances 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 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 levels to varying degrees. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in these wells.

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Corporation's financial position

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 the Corporation is ultimately able to produce from its reserves.

Regulatory 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 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 waterflooding. If the Corporation is unable to access such water it may not be able to undertake hydraulic fracturing or waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs.

Changes in government controls, legislation or regulations that affect the oil and gas industry, or failing to comply with such controls, legislation or regulations, could adversely affect us

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 and, with respect to pricing and taxation of oil and natural gas, by agreements among the governments of Canada, Alberta, Saskatchewan, the United States and Texas, all of which should be carefully considered by investors in the oil and gas industry. 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 and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition, results of operations or prospects. See "*Industry Conditions*".

The oil and gas industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Other government controls, legislation or regulations may change from time to time in response to economic or political conditions. 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 us. In addition, failure to comply with government controls, legislation or regulations may result in the suspension, curtailment or termination of operations and subject us to liabilities and administrative, civil and criminal penalties. Compliance costs can be significant. See "*Industry Conditions*".

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 and provincial 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.

The oil and gas industry is highly regulated and changes in environmental, health and safety controls, legislation or regulations may impose restrictions, costs or other liabilities which may have an adverse affect on our business

All phases of our operations are subject to environmental, health and safety regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, state and municipal laws and regulations (collectively, "**environmental regulations**") governing occupational health and safety aspects of our operations, the spill, release or emission of materials 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, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose, among other things, 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. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The provinces of Alberta and Saskatchewan 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. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes in the ratio of our deemed assets to deemed liabilities or 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, including private parties commencing actions and new theories of liability, 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 affecting the oil and gas industry generally could reduce demand for crude oil and natural gas, resulting 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 - Environmental and Occupational Safety and Health Regulation*".

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas 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 in the United States by the Hart-Scott-Rodino Antitrust Improvements Act.

Public perception and its influence of 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, 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.

Climate change initiatives may impose restrictions or costs on our business which have a material adverse affect on our business

Our exploration and production facilities and other operational activities emit greenhouse gases ("**GHG**"). As such, it is highly likely that GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us.

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

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

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*".

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

There is a risk that the interest rates will increase given the current historical low level of interest rates. 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 future growth, potentially resulting in a decrease to the market price of our Common Shares.

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 our Credit Facilities and a large portion of our Senior Notes are 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.

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 may also 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"*.

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

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"*.

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. In addition, income tax laws and government incentive programs relating to the oil and gas industry may change in a manner that adversely affects the market price of the Common Shares.

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 Annual Information Form 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, 2018 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 price assumptions utilized in the Baytex Reserves Report, 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 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 and terrorism; and other adverse risks to the environment.

Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect on our business, financial condition, results of operations and prospects.

We are 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 flows 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.

We are subject to a number of additional business risks which could adversely affect our income and financial condition

Our business involves many operating risks related to acquiring, developing and exploring for oil and natural gas which even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our operational risks include, but are not limited to: operational and safety considerations; pipeline transportation and interruptions; reservoir performance and technical challenges; partner risks; competition; land claims; our ability to hire and retain necessary skilled personnel; the availability of drilling and related equipment; our ability to access new technology; seasonality and access restrictions; timing and success of integrating the business and operations of acquired assets and companies; phased growth execution; risk of litigation, regulatory issues, increases in government taxes and changes to royalty or mineral/severance tax regimes; and risk to our reputation resulting from operational activities that may cause personal injury, property damage or environmental damage.

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 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 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. 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.

Alternatives to and changing demand for petroleum products

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 affect 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 flows and the value of its assets.

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. 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 our information technology systems are considered to be secure, if an unauthorized party is able to access the systems then such unauthorized access may compromise our business in a materially adverse manner.

Risks Relating 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 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.

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); however, we also follow the United States practice of separately reporting reserves volumes on a net basis (after the deduction of royalties and similar payments). 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 Annual Information Form 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 Annual Information Form may not be comparable to United States standards.

As a consequence of the foregoing, our reserves estimates and production volumes in this Annual Information Form 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. The Government of Alberta sets a target as to how much total production it wants to occur each month and then provides each producer a production allocation that is determined in part based upon each producer's prior year production measured over a one month or six month period. The overall production target was set at 3.56 million bbl/d in January and was increased to 3.63 million bbl/d in February. Under the current rules, the Government of Alberta has the authority to limit production until December 31, 2019. It is not certain what the quantum of the production curtailments will be for the balance of 2019, whether there will be further changes to the rules used to determine the production allocations or whether the government will announce new rules to implement production curtailments beyond December 31, 2019.

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.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. 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. NAFTA 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.

A revised version of NAFTA has been agreed to by all three countries for approval under a new name - United States Mexico Canada Agreement "**USMCA**". The USMCA is awaiting legislative approval before it comes into force. The energy sector is not expected to be significantly impacted by the USMCA if and when it comes into force.

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 western Canada, 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 have each implemented similar liability management programs in respect of most conventional upstream oil and gas wells, facilities and pipelines. These programs require a licensee whose deemed liabilities exceed its deemed assets within the jurisdiction to provide a security deposit. In response to a number of insolvencies, Alberta and Saskatchewan have made their liability management programs more stringent in recent years. In particular, a licensee is held to a higher standard when accepting the transfer of licensees from a third party. This has reduced the number of parties which can acquire assets.

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 and Occupational Safety and Health Regulation

The oil and natural gas industry is currently subject to stringent environmental, health and safety regulation pursuant to a variety of municipal, provincial, state and federal controls, laws, and regulations governing occupational health and safety aspects of our operations, 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, occupational safety and health, environmental conservation, cultural and natural resources protection are 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 Occupational Safety and Health Administration ("**OSHA**"), Federal Environmental Protection Agency ("**EPA**"), Texas Commission on Environmental Quality ("**TCEQ**") and the RRC.

The OSHA regulates working conditions by setting and enforcing safety and health standards through multiple federal Acts of Congress, most notably the Occupational Safety and Health Act of 1970. OSHA frequently amends/updates regulations, and has recently increased its attention given to the oil and gas industry. 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 of 1990, the Comprehensive Environmental Response, Compensation and Liability Act of 1980 and the Resource Conservation and Recovery 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. Additionally, Canada pledged to reduce GHG emissions by 30% by 2030 from 2005 levels. In 2017, the United States announced that it would withdraw from the Paris Agreement at its first opportunity in 2020 and would, in the meantime, cease implementing the pledges made in connection with the Paris Agreement.

The Government of Canada has announced that it intends to implement a carbon tax in 2018 starting at $10/tonne rising by $10/tonne a year to $50/tonne by 2022. This federal carbon tax is intended to be implemented in concert with the provinces and territories and would only be implemented in those provinces and territories that do not have their own carbon tax.

The Province of Alberta announced and implemented a broad range of plans targeting GHG emissions, that include: a carbon levy of $20/tonne effective January 1, 2017, which increased to $30/tonne as of January 1, 2018; a cap on GHG emissions from the oil sands of 100 mega tonnes per year; and a plan to introduce regulations that will reduce methane emissions from oil and gas operations by 45% by 2025. The Province of Saskatchewan has set forth similar legislation that is not yet in force for facilities that emit more than 50,000 tonnes of GHGs.

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.

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, did not pay a dividend in 2016, 2017 or 2018 and do not currently have any plans to resume the payment of cash dividends. 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, debt covenants and obligations, fluctuations in working capital, the timing and amount of capital expenditures, applicable law and other factors beyond our control.

In addition, the payment of dividends by us is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. Pursuant to the Credit Facilities, we are restricted from paying dividends to Shareholders if a default, or event of default has occurred and is continuing and, if no default or event of default has occurred which is continuing, where the dividend would or would reasonably be expected to have a material adverse effect on our ability to fulfill our obligations under the Credit Facilities or under any hedge agreements with lenders (or their affiliates) under the Credit Facilities. The indentures governing our Senior Notes also contain certain limitations on restricted payments. Restricted payments include the declaration or payment of any dividend or distribution by us. For full particulars of the covenants, reference should be made to the indentures governing our Senior Notes and to our Credit Facilities, copies of which are accessible on the SEDAR website, see "*Material Contracts*" for further details.

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 Annual Information Form, 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, to attend and to one vote per share held at any meeting of the shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation other than the Common Shares as such).

Holders of Common Shares will be entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class, 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

The preferred shares may be issued in one or more series, at any time or from time to time. Before any shares of a particular series are issued, the Board of Directors will fix the number of shares that will form such series and will, subject to the limitations set out in the preferred share terms described below, fix the designation, rights, privileges, restrictions and conditions to be attached to the preferred shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for securities of Baytex or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than preferred shares or payment in respect of capital on any shares in the capital of Baytex or creation or issue of debt or equity securities; the whole subject to filing of Articles of Amendment setting forth a description of such series including the designation, rights, privileges, restrictions and conditions attached to the shares of such series. Notwithstanding the foregoing: (a) the Board of Directors may at any time or from time to time change the rights, privileges, restrictions and conditions attached to unissued shares of any series of preferred shares; and (b) other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the preferred shares will be limited to one vote per Preferred Share at any meeting where the preferred shares and Common Shares vote together as a single class.

The preferred shares of each series will rank equally with the preferred shares of every other series with respect to accumulated dividends and return of capital. The preferred shares will be entitled to a preference over the Common Shares and over any other shares of Baytex ranking junior to the preferred shares with respect to priority in the payment of dividends and in the distribution of assets in the event of the liquidation, dissolution or winding-up of Baytex, whether voluntary or involuntary, or any other distribution of the assets of Baytex among its shareholders for the purpose of winding-up its affairs. If any cumulative dividends or amounts payable on a return of capital are not paid in full, the preferred shares of all series will participate rateably in respect of such dividends, including accumulations, if any, in accordance with the sums that would be payable on such shares if all such dividends were declared and paid in full, and in respect of any repayment of capital in accordance with the sums that would be payable on such repayment of capital if all sums so payable were paid in full; provided, however, that in the event of there being insufficient assets to satisfy in full all such claims as aforesaid, the claims of the holders of the preferred shares with respect to repayment of capital will first be paid and satisfied and any assets remaining thereafter shall be applied towards the payment in satisfaction of claims in respect of dividends. The preferred shares of any series may also be given such other preferences not inconsistent with the terms of the preferred shares over the Common Shares and any other shares ranking junior to the preferred shares as may be determined in the case of each such series of preferred shares.

The rights, privileges, restrictions and conditions attaching to the preferred shares may be repealed, altered, modified, amended or amplified or otherwise varied only with the sanction of the holders of the preferred shares given in such manner as may then be required by law, subject to a minimum requirement that such approval be given by resolution passed by the affirmative vote of at least two-thirds of the votes cast at a meeting of holders of preferred shares duly called for such purpose and held upon at least 21 days' notice at which a quorum is present comprising at least two persons present, holding or representing by proxy at least 10 percent of the outstanding preferred shares or by a resolution in writing of all holders of the outstanding preferred shares. If any such quorum is not present within half an hour after the time appointed for the meeting, then the meeting shall be adjourned to a date being not less than seven days later and at such time and place as may be appointed by the chairman and at such meeting a quorum will consist of that number of shareholders present in person or represented by proxy. The formalities to be observed with respect to the giving of notice of any such meeting or adjourned meeting and the conduct thereof shall be those which may from time to time be prescribed in the by-laws of Baytex with respect to meetings of Shareholders. On every vote taken at every such meeting or adjourned meeting each holder of a Preferred Share shall be entitled to one vote in respect of each one dollar of stated value of preferred shares held.

Senior Notes

On February 17, 2011, we issued US$150 million principal amount of 6.75% series B senior unsecured debentures due February 21, 2021. The 2021 Debentures pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on February 17, 2016 at the redemption prices specified in Debt Indenture #1.

On July 19, 2012, we issued $300 million principal amount of 6.625% series C senior unsecured debentures due July 19, 2022. The 2022 Debentures pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on July 19, 2017 at the redemption prices specified in Debt Indenture #1.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 and US$400 million of 5.625% notes due June 1, 2024. The 2021 Notes and the 2024 Notes pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on June 1, 2017 (in the case of the 2021 Notes) and June 1, 2019 (in the case of the 2024 Notes) at the redemption prices specified in Debt Indenture #2.

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 the Revolving Facilities and the Term Loan. The Revolving Facilities consist of: (i) a US$35 million operating loan and a US$340 million syndicated loan for Baytex and (ii) a US $200 million syndicated loan for Baytex USA. The Revolving Facilities are secured and have an extendible four-year term that, unless extended by the lenders, will mature on June 4, 2020. The Term Loan is a $300 million syndicated loan for Baytex Energy Limited Partnership. The Term Loan does not revolve, is with the same syndicate of lenders as the Revolving Facilities and also matures on June 4, 2020.

For additional details regarding the covenants in our Credit Facilities and our compliance therewith, see our MD&A for the year ended December 31, 2018. 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.

Baytex has been assigned a corporate credit rating of BB with a stable outlook and our Senior Notes have been assigned a credit rating of BB by Standard and Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("**S&P**"). 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 "BB" is considered less vulnerable to non-payment than other speculative issues, however it faces ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inability to meet its financial obligations. 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 Investor Service Inc. ("**Moody's**") has assigned Baytex a corporate family credit rating of B1, assigned our Senior Notes a credit rating of B2 and stated that our rating outlook is stable. 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 "Caa" are rated as being poor quality and a very 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.

The credit ratings accorded to Baytex by S&P and Moody's 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 and Moody's in connection with the assignment of ratings to our long-term debt and may make payments to S&P and Moody's in the future in connection with the confirmation of such ratings for purposes of the offering of debt securities.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and the NYSE under the trading symbol "BTE". The following table outlines the share price trading range and volume of shares traded by month in 2018.

	Canada Composite Trading			United States Composite Trading		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High (US$)	Low (US$)	Volume Traded
2018						
January	4.35	3.66	141,677,233	3.54	2.97	44,114,735
February	3.87	3.01	92,345,877	2.55	2.38	33,080,354
March	4.00	3.05	112,444,289	3.04	2.37	41,043,628
April	5.83	3.34	199,963,925	4.55	2.59	52,355,947
May	6.23	5.10	232,750,483	4.85	4.04	65,896,429
June	5.69	4.21	283,604,134	4.38	3.16	57,560,556
July	4.73	3.88	146,771,729	3.62	2.98	39,244,788
August	4.50	3.51	217,845,970	3.44	2.66	52,628,170
September	4.01	3.37	241,558,115	3.11	2.56	48,690,188
October	4.03	2.49	291,948,490	3.13	1.90	65,405,615
November	2.94	2.20	268,015,054	2.24	1.67	59,355,006
December	2.74	1.87	264,537,203	2.08	1.38	56,897,347

DIRECTORS AND OFFICERS

The following table sets forth the name, municipality of residence, age as at December 31, 2018, position held with Baytex and principal occupation of each of the directors and officers of Baytex. The Board committee memberships and Lead Independent director designation is as of March 5, 2019.

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
Neil J. Roszell Calgary, Alberta	51	Chairman of the Board	Chairman of the Board, Baytex
Edward D. LaFehr Calgary, Alberta	59	Director, President and Chief Executive Officer	President and Chief Executive Officer, Baytex
Mark R. Bly (1)(2) Incline Village, Nevada	59	Lead Independent Director	Independent Businessman
Gary R. Bugeaud (3) Calgary, Alberta	57	Director	Independent Businessman
Raymond T. Chan (3) Calgary, Alberta	63	Director	Independent Businessman
Trudy M. Curran (1)(4) Calgary, Alberta	56	Director	Independent Businesswoman
Naveen Dargan (2)(5) Calgary, Alberta	61	Director	Independent Businessman
Gregory K. Melchin (4)(5) Calgary, Alberta	65	Director	Independent Businessman
Kevin D. Olson (1)(5) Calgary, Alberta	50	Director	President and Portfolio Manager of a private investment firm
David L. Pearce (2)(4) Calgary, Alberta	65	Director	Deputy Managing Partner, Azimuth Capital Management
Richard P. Ramsay (6) Calgary, Alberta	55	Executive Vice President and Chief Operating Officer	Executive Vice President and Chief Operating Officer, Baytex
Rodney D. Gray Calgary, Alberta	47	Executive Vice President and Chief Financial Officer	Executive Vice President and Chief Financial Officer, Baytex
Jason J. Jaskela (6) Calgary, Alberta	42	Executive Vice President, Shale Oil	Executive Vice President, Shale Oil, Baytex
Kendall D. Arthur Calgary, Alberta	38	Vice President, Heavy Oil	Vice President, Heavy Oil, Baytex
Brian G. Ector Calgary, Alberta	50	Vice President, Capital Markets	Vice President, Capital Markets, Baytex
Jonathan L. Grimwood Calgary, Alberta	48	Vice President, Exploration	Vice President, Exploration, Baytex
Chad L. Kalmakoff Calgary, Alberta	42	Vice President, Finance	Vice President, Finance, Baytex
Chad E. Lundberg Calgary, Alberta	37	Vice President, Viking Business Unit	Vice President, Viking Business Unit, Baytex
M. Scott Lovett Calgary, Alberta	45	Vice President, Corporate Development	Vice President, Corporate Development, Baytex
Scott E. Rideout Calgary, Alberta	39	Vice President, Land	Vice President, Land, Baytex

Notes:

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

(2) Member of our Reserves Committee.

(3) On March 5, 2019 we announced that Mr. Chan and Mr. Bugeaud are not standing for re-election to the board of directors.

(4) Member of our Nominating and Governance Committee.

(5) Member of our Audit Committee.

(6) On March 5, 2019 we announced that Richard P. Ramsay would be retiring from Baytex as of April 5, 2019 and Jason J. Jaskela would be appointed Executive Vice President and Chief Operating Officer.

Listed below is a biographical description for each of our directors and officers, including their principal occupations during the five preceding years.

Neil J. Roszell was appointed Chairman of the Board of Baytex on August 22, 2018. He is a professional engineer with 25 years of industry experience. Mr. Roszell was the Executive Chairman and Chief Executive Officer of Raging River from June 2017 until August 2018 and Raging River's President and Chief Executive Officer from incorporation in 2012. Mr. Roszell was the President and Chief Executive Officer of Wild Stream Exploration Inc. from October 2009 until March 2012, the President and Chief Executive Officer of Wild River Resources Ltd. from February 2007 until July 2009, the President and Chief Operating Officer of Prairie Schooner Energy Ltd. from August 2004 until September 2006 and the Vice President, Engineering of Great Northern Exploration Ltd. from September 2001 to June 2004. He received a Bachelor of Applied Science degree in Engineering from the University of Regina in 1991.

Edward D. LaFehr joined Baytex as President on July 18, 2016 and was appointed Chief Executive Officer on May 4, 2017. Mr. LaFehr has nearly 35 years of experience in the oil and gas industry working with Amoco, BP, Talisman and the Abu Dhabi National Energy Company ("TAQA") in various geographies. Before joining Baytex, Mr. LaFehr was President of TAQA's North American oil and gas business which led to his subsequent role as Chief Operating Officer of TAQA, globally. Prior to this, he served as Senior Vice President for Talisman Energy, accountable for its Canadian business. Mr. LaFehr has a long track record of success in the oil and gas industry leading organizations, growing assets and joint ventures, and driving capital and cost efficiencies. He was recently nominated for election as a director of TransGlobe Energy Corporation, an exploration and production company whose activities are concentrated in Egypt and Canada. Mr. LaFehr holds Masters degrees in geophysics and mineral economics from Stanford University and the Colorado School of Mines, respectively.

Mark R. Bly was appointed Lead Independent Director on March 5, 2019 after having been appointed to the Board in 2017. Mr. Bly is an independent businessman with over 35 years of experience in the oil and gas industry, primarily with BP, a global producer of oil and gas. At BP, Mr. Bly held various senior leadership roles in its domestic and international operations, including leading the North American onshore unit, Group Vice President for approximately 25% of BP's global production, and Executive Vice President of Group Safety and Operational Risk. Since retiring from BP in 2013, Mr. Bly has worked with private oil and gas production and service companies serving as an executive, board member and advisor. Mr. Bly holds a Master of Science degree in structural engineering from the University of California, Berkeley and a Bachelor of Science degree in civil engineering from the University of California, Davis.

Gary R. Bugeaud was appointed to the Board on August 22, 2018. He retired (December 31, 2013) as Managing Partner of Burnet, Duckworth & Palmer LLP and is now a Corporate Director. Mr. Bugeaud was a director of Raging River Exploration Inc. from January 2014 until August 2018. He is a director of Freehold Royalties Ltd. and a Member of the Dean's Advisory Committee of the College of Law of the University of Saskatchewan. He is a former corporate lawyer with over 23 years of legal experience focused on securities, corporate finance, mergers and acquisitions, and corporate governance matters. Mr. Bugeaud has a Bachelor of Commerce (Finance) degree and a Bachelor of Laws degree from the University of Saskatchewan. Mr. Bugeaud holds the ICD.D designation from the Institute of Corporate Directors.

Raymond T. Chan joined Baytex in October 1998 and has held the following positions: Senior Vice President and Chief Financial Officer (October 1998 to 55 August 2003); President (September 2003 to November 2007); Chief Executive Officer (September 2003 to December 2008); Interim Chief Executive Officer (May 2012 to September 2012) Executive Chairman (January 2009 to May 2014); Chairman of the Board (May 2014 to August 2018) and Lead Independent director (August 2018 to March 2019). Mr. Chan served as a director of Baytex Energy from October 1998 to December 2014. Mr. Chan has held senior executive positions in the Canadian oil and gas industry since 1982, including chief financial officer titles at Tarragon Oil and Gas Limited, American Eagle Petroleums Ltd. and Gane Energy Corporation. Mr. Chan holds a Bachelor of Commerce degree and is a Chartered Accountant.

Trudy M. Curran is a retired businesswoman with experience in executive compensation, mergers and acquisitions, financing and governance. She is currently serving as interim managing director of Riversdale Resources Ltd., a public Australian incorporated metallurgical coal development company. She served as an officer of Canadian Oil Sands Limited from September 2002 to the time of its sale in February 2016. As Senior Vice President, General Counsel & Corporate Secretary of Canadian Oil Sands Limited, she was responsible for legal, human resources and administration and a member of the executive team focused on strategy and risk management. From 2003 to 2016, she was a director of Syncrude Canada Ltd. where she served as chair of the Human Resources and Compensation Committee and as a member of the Pension Committee. She serves on the Executive Committee of the Calgary chapter of the Institute of Corporate Directors and is a member of the Alberta Securities Commission and serves on its Human Resources and Compensation Committee. Ms. Curran holds a Bachelor of Arts degree in English and a Bachelor of Laws degree (both with distinction) from the University of Saskatchewan and the ICD.D designation from the Institute of Corporate Directors.

Naveen Dargan has been an independent businessman since June 2003. Prior thereto, he worked for over 20 years in the investment banking business, finishing his career as Senior Managing Director and Head of Energy Investment Banking at Raymond James Ltd. Since 2003, Mr. Dargan has served on various Boards for companies in the Energy Industry, Energy Services Industry and one Philanthropic Organization. Mr. Dargan holds a Bachelor of Arts (Honours) degree in Mathematics and Economics from Queen's University, a Master of Business Administration degree from the Schulich School of Business and a Chartered Business Valuator designation.

Gregory K. Melchin is currently the Chairperson of the Board of Directors of ENMAX Corporation, a municipally-owned utility. Mr. Melchin was a member of the Legislative Assembly of Alberta from March 1997 to March 2008. Among his various assignments with the Government of Alberta, he was Minister of Energy, Minister of Seniors and Community Supports and Minister of Revenue. Prior to being elected to the Legislative Assembly of Alberta, he served in various management positions for 20 years in the Calgary business community. Mr. Melchin holds a Bachelor of Science degree (major in accounting), a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta and the ICD.D designation from the Institute of Corporate Directors.

Kevin D. Olson was appointed to the Board on August 22, 2018. He has 25 years of experience in energy investing, investment banking and the Canadian upstream energy industry. He is currently the President & Portfolio Manager of a private investment firm. Mr. Olson was a director of Raging River from March 2012 to August 2018. Prior thereto, Mr. Olson was President and Portfolio Manager of EnergyX Equity Inc. from 2001 to 2011. Mr. Olson was Vice President, Corporate Development of Northrock Resources Ltd. from 2000 to 2001. From 1993 to 2000 Mr. Olson worked with FirstEnergy Capital Corp. as Vice-President, Corporate Development. He currently serves on Gear Energy Ltd.'s board and had previously served on several Canadian public and private energy and energy service company boards. Mr. Olson holds a Bachelor of Commerce degree (with distinction) majoring in finance and accounting from the University of Calgary.

David L. Pearce was appointed to the Board on August 22, 2018. Mr. Pearce has been working with the Private Equity Energy firm Azimuth Capital Management since July 2014 as Deputy Managing Partner. He was an Operating Partner with the Azimuth predecessor KERN Partners from November 2008 to July 2014. Mr. Pearce was a director of Raging River Exploration Inc. from March 2012 to August 2018. He was with Northrock Resources Ltd. from June 1999 to January 2008 where he held several senior officer positions and most recently was the President and Chief Executive Officer. Prior thereto Mr. Pearce worked in various Management roles at Fletcher Challenge Canada, Amoco Canada and Dome Petroleum. He has a Bachelor of Science in Mechanical Engineering (Honors) from the University of Manitoba.

Richard P. Ramsay was appointed Executive Vice President and Chief Operating Officer of Baytex on August 22, 2018 and served as Chief Operating Officer from May 2014 to August 2018. He originally joined Baytex in January 2010 and has held the following positions: Vice President, Heavy Oil (January 2010 to January 2012) and Vice President, Alberta/B.C. Business Unit (January 2012 to May 2014). Mr. Ramsay has over 25 years of experience in the Canadian oil and gas industry and was formerly Chief Operating Officer of TAQA North Ltd. He previously held a variety of technical and management positions with Northrock Resources Ltd., Fletcher Challenge Energy Canada Inc., Amoco Canada Petroleum Ltd. and Dome Petroleum Ltd. Mr. Ramsay has a Bachelor of Science degree with Distinction in Mechanical Engineering from the University of Saskatchewan and is a practicing member of the Association of Professional Engineers and Geoscientists of Alberta.

Rodney D. Gray was appointed Executive Vice President and Chief Financial Officer of Baytex on August 22, 2018. He joined Baytex on April 7, 2014 and served as Chief Financial Officer from April 2014 to August 2018. Mr. Gray has over twenty years' experience in the oil and gas industry. Prior to joining Baytex, Mr. Gray held the position of Chief Financial Officer for CEDA International. Prior thereto, he spent eleven years with Enerplus Corporation, the last eight of which as Vice President, Finance, where areas of responsibility included corporate reporting, treasury and capital markets, operational accounting, business analysis, risk management and insurance. Mr. Gray is a Chartered Accountant and has a Bachelor of Commerce degree with Honours from Queen's University. He is very active in the community having been involved with several charitable organizations.

Jason J. Jaskela joined Baytex as Executive Vice President, Shale Oil on August 22, 2018. Mr. Jaskela is a professional engineer with 19 years of industry experience. Previously, Mr. Jaskela was Chief Operating Officer of Raging River Exploration Inc. from March 2014 until August 2018 and the Vice President, Production from March 2012 until March 2014. From October 2009 to April 2010 he held the position of Manager Engineering with Wild Stream Exploration Inc. and was the Vice President, Production from April 2010 until March 2012. Prior to Wild Stream, Mr. Jaskela held senior engineering roles with Encana Corporation (May 2000 to May 2006) and Mahalo Energy Ltd. (May 2006 to October 2009). Mr. Jaskela graduated with a Bachelor of Science degree in Engineering in 2000.

Kendall D. Arthur was appointed Vice President, Lloydminster Business Unit of Baytex on March 4, 2015 and became Vice President, Lloydminster and Conventional Business Units on February 20, 2017. Mr. Arthur has over 10 years of experience in the Canadian oil and gas industry. He joined Baytex Energy in 2006 as a Production Engineer in the Heavy Oil Business Unit and held the position of Vice President, Saskatchewan Business Unit from January 2012 to March 2015. Prior to joining Baytex, he held various technical production, completions and operations roles with Husky Energy. Mr. Arthur received a Bachelor of Science degree in Mechanical Engineering from the University of Saskatchewan and is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Brian G. Ector is Vice President, Capital Markets of Baytex and is responsible for Baytex's equity capital markets and investor relations functions. He joined Baytex in November 2009. Prior to joining Baytex, Mr. Ector spent 15 years as a sell-side research analyst covering both energy trusts and exploration and production corporations. He spent the last seven years with Scotia Capital where he was consistently ranked as one of the top rated analysts in Canada. Mr. Ector received a Bachelor of Commerce degree with a concentration in finance from the University of Calgary and received his Chartered Financial Analyst designation in 1996. He is a national board member of the Canadian Investor Relations Institute as well as a member of the National Investor Relations Institute, the CFA Institute and the Calgary CFA Society.

Jonathan L. Grimwood joined Baytex as Vice President, Exploration on August 22, 2018. He was the Vice President of Exploration at Raging River Exploration Inc. from October 2017 to August 2018. Mr. Grimwood served as the President at Iron Bridge Resources Ltd. (formerly known as RMP Energy Inc. and Orleans Energy Ltd) from February 2017 to August 2017 and also served as its Vice President of Exploration from May 2011 to February 2017. He started his career at Poco Petroleums Ltd. in 1997 and held positions of increasing responsibility at Burlington Resources Canada Ltd., Rider Resources Ltd., and Galleon Energy

Inc. Mr. Grimwood earned a Bachelor of Science from Brandon University, a Masters Degree in Earth Sciences from the University of Waterloo, and is a Registered Member of APEGGA.

Chad L. Kalmakoff was appointed Vice President, Finance of Baytex on September 1, 2015. Mr. Kalmakoff has 20 years of experience in the oil and gas industry. Prior to joining Baytex, Mr. Kalmakoff was Vice President, Finance and Chief Financial Officer at Kicking Horse Energy Inc. from October 2014 to August 2015. From October 2013 to July 2014, he was Vice President, Finance and Chief Financial Officer at Corinthian Exploration Ltd. Prior thereto, he was Chief Financial Officer (March 2012 to March 2013) and Vice President, Finance (June 2006 to March 2012) at Pace Oil & Gas Ltd. and its predecessor, Midnight Oil Exploration Ltd. Mr. Kalmakoff is a Chartered Accountant and holds a Bachelor of Commerce from Dalhousie University.

Chad E. Lundberg joined Baytex as Vice President, Viking Business Unit on August 22, 2018. He is a professional engineer with 14 years of industry experience. Prior to his current position, Mr. Lundberg held the position of Vice President, Operations with Raging River Exploration Inc. from October, 2016 until August 2018. He held various technical and management roles with Crescent Point Energy Corporation from 2008 until September 2016. Prior to Crescent Point, Mr. Lundberg was an operations consultant from October 2005 until May 2008 and held a completions position at Husky Energy from May 2004 until October 2005. Mr. Lundberg graduated with a Bachelor of Science in Engineering and is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

M. Scott Lovett was appointed Vice President, Business Development of Baytex on September 5, 2017. Mr. Lovett is a professional engineer and has over 20 years of experience in the oil and gas industry, including reservoir evaluations, acquisitions and divestments, business planning, and strategic analysis. From March 2014 to September 2017, he held a number of positions of increasing responsibility at Eagle Energy Inc., including Executive Vice President, Business Development. From September 2011 to March 2014, he was an officer of Native American Resource Partners, initially serving as Senior Vice President and then Chief Operating Officer. Prior thereto, he held various engineering and management roles at GLJ Petroleum Consultants Ltd. and Enerplus Corporation. Mr. Lovett holds a Bachelor and Master in Science degrees in Chemical Engineering and a Master in Business Administration, all from the University of Calgary.

Scott E. Rideout joined Baytex as Vice President, Land on August 22, 2018. He is a landman with over 14 years of industry experience. He held the position of Vice President Land with Raging River Exploration Inc. from July 2014 until August 2018. Mr. Rideout held roles of increasing responsibility at Surge Energy Inc. from October 2010 until July 2014 where he was most recently the Manager of Business Development and Land. He started his career at Talisman Energy Inc. and was a Land Negotiator at Provident Energy Trust, Kereco Energy Ltd., and Galleon Energy Inc. Mr. Rideout earned an Economics degree from the University of Calgary in 2002 and is a registered member of CAPL.

Ownership of Securities by Management

As at March 1, 2019, the directors and officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 17,475,082 Common Shares, representing approximately 3.1 percent of the issued and outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

Other than as disclosed below, no director or executive officer of Baytex (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including 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.

Mr. Dargan, a director of Baytex, was formerly a director of Tervita Corporation (a private environmental solutions company). Tervita made a proposal under the *Canada Business Corporations Act* on September 14, 2016 and a voluntary filing under Chapter 15 of the United States Bankruptcy Code on October 20, 2016, which resulted in a plan of arrangement under the *Canada Business Corporations Act*. Mr. Dargan resigned as a director of Tervita on December 13, 2016.

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 Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including 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 Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver-manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

In addition, 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.

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 D.

Composition of the Audit Committee

The members of our Audit Committee are Naveen Dargan, Gregory K. Melchin and Kevin D. Olson, each of whom is "independent" and "financially literate", with the meaning of National Instrument 52-110 "Audit Committees". The relevant education and experience of each Audit Committee member is outlined below:

Name	Relevant Education and Experience
Naveen Dargan	Bachelor of Arts (Honours) degree in Mathematics and Economics, Master of Business Administration degree and Chartered Business Valuator designation. Independent businessman since June 2003; prior thereto Senior Managing Director and Head of Energy Investment Banking of Raymond James Ltd.
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.
Kevin D. Olson	Bachelor of Commerce degree (with distinction) majoring in finance and accounting from the University of Calgary. Currently the President & Portfolio Manager of a private investment firm. Prior thereto, Vice President, Corporate Development of Northrock Resources from 2000-2001 and from 1993-2000, Vice President Corporate Development with FirstEnergy Capital Corp.

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 2018 and 2017:

Year	Audit Fees(1)	Audit-Related Fees(2)	Tax Fees(3)	All Other Fees(4)	Total
2018	$ 973	$ 199	$ 30	$ —	$ 1,202
2017	$ 684	$ 50	$ —	$ 5	$ 739

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 2018 and 2017 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. For fiscal 2018, audit-related fees included fees associated with securities filings associated with the Raging River strategic combination.

(3) Tax fees include fees tax compliance, tax advice and tax planning. For fiscal 2018, tax fees include fees associated with a transfer pricing study.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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. These reassessments follow the previously disclosed letter which we received in November 2014 from the CRA, proposing to issue such reassessments.

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 and we estimate the appeals process could take up to one 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 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 Income Tax Act (Canada). 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.

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

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a 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

Other than in connection with the Raging River merger as disclosed in the joint information circular of Baytex and Raging River filed on SEDAR on July 20, 2018, 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 of 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

Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar for the Common Shares in Canada, the 2021 Debentures and the 2022 Debentures. Computershare Trust Company, N.A., at its principal office in Canton, Massachusetts, is the transfer agent and registrar for the Common Shares in the United States, the 2021 Notes and the 2024 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 credit agreement in respect of the Revolving Credit Facilities (filed on April 13, 2016), the first amendment thereof (filed on May 2, 2018) and the second amendment thereof (filed on October 12, 2018;

(b) the credit agreement in respect of the Term Facility (filed on October 12, 2018).

(c) Debt Indenture #1 (filed on January 10, 2011) and supplemental indentures thereto (filed on February 22, 2011, July 19, 2012, January 14, 2013, August 13, 2014, September 9, 2014, March 9, 2015, February 20, 2018 and October 12, 2018);

(c) Debt Indenture #2 (filed on June 20, 2014) and supplemental indentures thereto (filed on August 13, 2014, September 9, 2014, February 20, 2018 and October 12, 2018); and

(d) our share award incentive plan (filed on April 18, 2016) and our amended share award incentive plan (filed on January 28, 2018).

(e) Arrangement Agreement between Baytex Energy Corp. and Raging River Exploration Inc., (filed on June 27, 2018) and the amended and restated Arrangement Agreement (filed on July 10, 2018).

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 Sproule, Ryder Scott and GLJ, our independent qualified reserves evaluators. None of the designated professionals of Sproule, Ryder Scott and GLJ 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 and special meeting of Shareholders to be held on May 2, 2019. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2018 and the related MD&A which are accessible on the SEDAR website at *www.sedar.com*.

For additional copies of this Annual Information Form 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 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) *"Edward D. LaFehr"*	(signed) *"Rodney D. Gray"*
Edward D. LaFehr	Rodney D. Gray
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer
(signed) *"David L. Pearce"*	(signed) *"Mark R. Bly"*
Director and Chairperson of the Reserves Committee	Director and Member of the Reserves Committee

March 12, 2019

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Form 51-101F2

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

1. We have evaluated Baytex's reserves data as at December 31, 2018. The reserves data is an estimate of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

2. The reserves data is the responsibility of Baytex'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 form 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 is in accordance with principles and definitions presented in the COGE Handbook.

5. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Baytex evaluated by us for the year ended December 31, 2018, and identifies the respective portions thereof that we have evaluated and reported on to the management and Board of Directors of Baytex:

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**
Sproule Associates Limited	December 31, 2018	Canada	—	3,785,233	—	3,785,233
Ryder Scott Company, L.P.	December 31, 2018	Texas, USA	—	2,257,957	—	2,257,957
GLJ Petroleum Consultants Ltd.	December 31, 2018	Canada	—	141,827	—	141,827
TOTALS				6,185,017		6,185,017

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

8. We have no responsibility to update the report referred to in paragraph 5 for events and circumstances occurring after its preparation date.

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

10. Executed as to our reports referred to above on March12, 2019.

SPROULE ASSOCIATES LIMITED		**RYDER SCOTT COMPANY, L.P.**	
(signed) *"Cameron Six"*		(signed) *"David Haugen"*	
Name	Cameron Six	Name	David Haugen
Title	President & CEO	Title	Senior Vice President
Location	Calgary, Alberta	Location	Calgary, Alberta

GLJ PETROLEUM CONSULTANTS LTD.

(signed) *"Chad Lemke"*	
Name	Chad Lemke
Title	Vice President
Location	Calgary, Alberta

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 recommending to 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:

1. assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
2. facilitate communication between directors and the external auditors;
3. enhance the external auditors' independence;
4. increase the credibility and objectivity of financial reports; and
5. strengthen the role of the independent directors by facilitating in depth discussions between the Committee, 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"). The members of the Committee shall be appointed by the Board from time to time.
2. The Board shall appoint a Chair of the Committee, who shall be an independent director.
3. 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 oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. 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:

- identifying, monitoring and mitigating business risks; and
- ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the interim and annual financial statements of the Corporation prior to their submission to the Board for approval. The review process should include, without limitation:

   - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors;
   - obtaining explanations of significant variances with comparative reporting periods; and
   - 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, press releases and the annual information form. 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. With respect to the external auditors of the Corporation, the Committee shall:

   - recommend to the Board the appointment of the external auditors, including the terms of their engagement for the integrated audit;
   - review and approve any other services to be provided by the external auditors (including the fee for such services); and
   - 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.

6. Review with the external auditors (and the internal auditor if one is appointed by the Corporation) 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.

7. 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 such other procedures as may be established by the Committee from time to time.

8. The Committee shall review the risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

9. 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.

10. 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.

11. 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.

12. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.

13. 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 chairman of the meeting shall 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 chairman 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 chairman 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 Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

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

Approved by the Board of Directors on February 28, 2011