



# Crescent Point

CRESCENT POINT ENERGY CORP.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2019

Dated March 4, 2020

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## SPECIAL NOTES TO READER

Any "financial outlook" or "future oriented financial information" in this annual information form, as defined by applicable securities legislation has been approved by management of Crescent Point (as defined herein). Such financial outlook or future oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

This annual information form and other reports and filings made with the securities regulatory authorities include certain statements that constitute "forward-looking statements" within the meaning of section 27A of the Securities Act of 1933, section 21E of the Securities Exchange Act of 1934 and the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" for the purposes of Canadian securities regulation (collectively, "forward-looking statements"). All forward-looking statements are based on our beliefs and assumptions based on information available at the time the assumption was made. Crescent Point has tried to identify such forward-looking statements by use of such words as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", "intend", "projected", "sustain", "continues", "strategy", "potential", "projects", "grow", "take advantage", "estimate", "well-positioned" and similar expressions, but these words are not the exclusive means of identifying such statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Crescent Point believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements speak only as of the date of this AIF or, if applicable, as of the date specified in this AIF.

In particular, this AIF contains forward-looking statements pertaining, among other things, to the following:

- corporate strategy and anticipated financial and operational performance;
- forecast prices and the expected impact of commodity price fluctuations on cash available to pay dividends;
- hedging strategy, including expected outcomes, and the approach to managing physical delivery contracts;
- risk mitigation strategy and the expected outcomes;
- the potential impact of competition and our working relationships with industry partners and joint operators on Crescent Point's business;
- business prospects;
- the performance characteristics of Crescent Point's oil and natural gas properties, including but not limited to oil and natural gas production levels;
- anticipated future cash flows and oil and natural gas production levels;
- projected returns and exploration potential of our assets;
- the potential of Crescent Point's plays;
- future development plans;
- forecast costs and expenses associated with Crescent Point's business, including capital expenditure programs and how they will be funded;
- leverage objectives;
- corporate and asset acquisitions and dispositions;
- drilling programs;
- expected location inventory development timing;
- expected production breakdown by area on a Proved and Proved plus Probable production basis;
- the quantity of oil and natural gas reserves;
- projections of commodity prices and costs;
- future waterflood programs;
- treatment of DRIP and SDP participants if either plan is reinstated;
- the impacts of the *Orphan Well Association v Grant Thornton Ltd.* court decision;
- expected decommissioning, abandonment, remediation and reclamation costs;
- Crescent Point's tax horizon;
- the impact of the Canada-United States-Mexico Agreement;
- expected trends in environmental regulation, including the anticipated impact the trends may have on operations and compliance costs;

- the impact, and projected long-term impacts, of the pricing of carbon and greenhouse gases;
- payment of dividends and the repurchase of Common Shares by the Corporation, including pursuant to its normal course issuer bid;
- supply and demand for oil and natural gas;
- expectations of regulatory changes and implementations and change in regulatory bodies;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes, including royalty regimes applicable to natural resources; and
- risks related to the regulatory, social and market efforts to address climate change.

By their nature, such forward-looking statements are subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements, including those material risks discussed in our Management's Discussion and Analysis for the year ended December 31, 2019, under the headings "Risk Factors" and "Forward-Looking Information" and as disclosed in this AIF. The material assumptions and factors in making forward-looking statements are disclosed in the Management's Discussion and Analysis for the year ended December 31, 2019, under the headings "Capital Expenditures", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Outlook".

This information contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Crescent Point's control. Such risks and uncertainties include, but are not limited to: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations, pipeline restrictions and blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions, including changes in laws and regulations, the adoption of new environmental laws and regulations, and changes in how environmental laws and regulations are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on tribal lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs and of dispositions and monetization; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; failure to realize the anticipated benefits of acquisitions and dispositions; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; tax laws and changes thereto, crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the control of Crescent Point, including those listed under "Risk Factors" in this AIF. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as each of these are interdependent and Crescent Point's future course of action depends on management's assessment of all information available at the relevant time.

Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserve values may be greater than or less than the estimates provided herein.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable crude oil, natural gas and natural gas liquids reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable crude oil, natural gas liquids and natural gas reserves attributable to any particular

group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Crescent Point's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. In addition, the discounted and undiscounted net present value of future net revenues attributable to reserves do not represent fair market value; and the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Crescent Point's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits, if any, Crescent Point will derive therefrom.

Barrels of oil equivalent ("**boe**") 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.

Operating netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback is calculated on a per boe basis as operating netback plus realized derivative gains and losses. Operating netback and netback are common metrics used in the oil and gas industry and are used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. The calculation of netback is shown in the Production History section of this AIF.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for the year.

Additional information on these and other factors that could affect Crescent Point's operations or financial results are included in Crescent Point's reports on file with Canadian and U.S. securities regulatory authorities (including our Annual Report on Form 40-F and Management's Discussion and Analysis). Readers are cautioned not to place undue reliance on the forward-looking information, which is given as of the date it is expressed in this AIF or otherwise. We do not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required pursuant to applicable securities laws. All subsequent forward-looking statements, whether written or oral, attributable to Crescent Point or persons acting on the Corporation's behalf are expressly qualified in their entirety by these cautionary statements.

### **Presentation of our Reserve and Resource Information**

Current SEC reporting requirements permit oil and gas companies to disclose Probable reserves (as defined herein), in addition to the required disclosure of Proved reserves. Under current SEC requirements, net quantities of reserves are required to be disclosed, which requires disclosure on an after royalties basis and does not include reserves relating to the interests of others. For a description of these and additional differences between Canadian and U.S. standards of reporting reserves, see "*Risk Factors — 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*".

### **New York Stock Exchange**

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

## GLOSSARY

In this AIF, the capitalized terms set forth below have the following meanings:

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

"**AEP**" means Alberta Environment and Parks.

"**AER**" means the Alberta Energy Regulator.

"**AIF**" means this annual information form of the Corporation dated March 4, 2020 for the year ended December 31, 2019.

"**Board**" or "**Board of Directors**" means the board of directors of the Corporation.

"**Common Shares**" means common shares in the capital of the Corporation.

"**Conversion Arrangement**" means the plan of arrangement under Section 193 of the ABCA, completed on July 2, 2009 pursuant to which the Trust effectively converted from an income trust to a corporate structure.

"**CPEUS**" means Crescent Point Energy U.S. Corp.

"**CPHI**" means Crescent Point Holdings Inc.

"**CPLux**" means Crescent Point Energy Lux S.à r.l.

"**CPUSH**" means Crescent Point U.S. Holdings Corp.

"**Crescent Point**" or the "**Corporation**" means Crescent Point Energy Corp., formerly Wild River Resources Ltd., a corporation amalgamated under the ABCA and, where applicable, includes its subsidiaries and affiliates.

"**DRIP**" means the Premium Dividend<sup>TM</sup> and Dividend Reinvestment Plan of the Corporation.

"**DSU Plan**" means the Deferred Share Unit Plan of the Corporation.

"**FAST Act**" means the *Fixing America's Surface Transportation Act*.

"**GLJ**" means GLJ Petroleum Consultants Ltd.

"**Greenhouse Gases**" or "**GHGs**" means any or all of, including but not limited to, carbon dioxide (CO<sub>2</sub>), methane (CH<sub>4</sub>), nitrous oxide (N<sub>2</sub>O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF<sub>6</sub>).

"**IFRS**" means International Financial Reporting Standards as adopted by the Canadian Accounting Standards Board for periods beginning on and after January 1, 2011.

"**MD&A**" means the management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2019.

"**NCIB**" means normal course issuer bid.

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

"**NYSE**" means the New York Stock Exchange.

"**OPEC**" means the Organization of the Petroleum Exporting Countries.

"**Partnership**" means Crescent Point Resources Partnership, a general partnership formed under the laws of the Province of Alberta, having CPHI and the Corporation as partners.

"**PSU Plan**" means the Performance Share Unit Plan of the Corporation.

"**Restricted Share Bonus Plan**" means the Restricted Share Bonus Plan of the Corporation.

"**SDP**" means the Share Dividend Plan of the Corporation.

"**SEC**" means the U.S. Securities and Exchange Commission.

"**Shareholders**" means the holders from time to time of Common Shares.

"**Sproule**" means Sproule Associates Limited.

"**Stock Option Plan**" means the Stock Option Plan of the Corporation.

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

"**Trust**" means Crescent Point Energy Trust, an unincorporated open ended investment trust governed by the laws of the Province of Alberta that was dissolved pursuant to the Conversion Arrangement.

"**Trust Units**" means the trust units of the Trust.

"**TSX**" means the Toronto Stock Exchange.

"**Unitholders**" means holders of Trust Units.

"**U.S.**" means the United States of America.

For additional definitions used in this AIF, please see "Statement of Reserves Data and Other Oil and Gas Information - Notes and Definitions".

In this AIF, references to "dollars" and "\$" are to the currency of Canada, unless otherwise indicated.

## SELECTED ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings:

### Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
bbls/d	barrels per day
Mbbls	thousand barrels
NGLs	natural gas liquids

### Natural Gas

Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet of gas equivalent converting one barrel of oil to 6 Mcf of natural gas equivalent
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMBTU	million British Thermal Units
GJ	gigajoule

### Other

AECO	the natural gas storage facility located at Suffield, Alberta
boe or BOE	barrels of oil equivalent 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	barrel of oil equivalent per day
m <sup>3</sup>	cubic metres
M\$	thousand dollars
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
MM\$	million dollars
MW	megawatt
MW/h	megawatt per hour
tCO <sub>2</sub> e	tonnes of carbon dioxide equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade



## CURRENCY OF INFORMATION

The information set out in this AIF is stated as at December 31, 2019, unless otherwise indicated. Capitalized terms used but not defined in the text are defined in the Glossary.

## OUR ORGANIZATIONAL STRUCTURE

### The Corporation

Crescent Point Energy Corp. ("**Crescent Point**" or the "**Corporation**" and, together with its direct and indirect subsidiaries and partnerships, where appropriate, "**we**", "**our**" or "**us**") is the successor to the Trust, following the completion of the "conversion" of the Trust from an income trust to a corporate structure under the Conversion Arrangement. Pursuant to the Conversion Arrangement, Unitholders of the Trust exchanged their Trust Units for Common Shares of the Corporation on a one-for-one basis.

The Corporation was originally incorporated pursuant to the provisions of the *Company Act* (British Columbia) on April 20, 1994 as 471253 British Columbia Ltd. 471253 British Columbia Ltd. changed its name to Westport Research Inc. ("**Westport**") on August 12, 1994. On August 1, 2006, Westport was continued into Alberta under the ABCA. On October 11, 2006, Westport changed its name to 1259126 Alberta Ltd. ("**1259126**"). On February 8, 2007, 1259126 amended its articles to change its name to Wild River Resources Ltd. ("**Wild River**"), to add a class of non-voting common shares, to change the number of authorized Common Shares from 1,000,000 to unlimited and to change the rights, privileges, restrictions and conditions attaching to such shares, to reorganize its share structure, to change the number of Wild River's issued and outstanding shares on a pro rata basis to an aggregate of 5,000,000 Common Shares, to remove the restrictions on share transfer and to amend the "other provisions" section of the articles. On June 29, 2009, Wild River amended its articles to cancel the non-voting common shares and to change the rights, privileges, restrictions and conditions of the Common Shares to remove the references to the non-voting common shares. On July 2, 2009, in connection with the Conversion Arrangement, Wild River filed Articles of Amendment to give effect to the consolidation of the Common Shares on the basis of 0.1512 of a post-consolidation Common Share for each pre-consolidation Common Share and subsequent Articles of Amendment to change its name to Crescent Point Energy Corp. On January 1, 2011, the Corporation amalgamated with Ryland Oil ULC, Darian Resources Ltd. and Shelter Bay Energy ULC.

The head and principal office of the Corporation is located at Suite 2000, 585 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and its registered office is located at Suite 3700, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

The Corporation is a conventional oil and gas producer with assets strategically focused in properties comprised of high quality, long life, operated, light and medium crude oil and natural gas reserves in Western Canada and the United States.

We make regular cash dividends to Shareholders from our net cash flow. Our primary source of cash flow is distributions from the Partnership.

### Partnership

The Partnership is a general partnership governed by the laws of the Province of Alberta. As set forth in the diagram below under "*Organizational Structure of the Corporation*", the partners of the Partnership are CPHI and the Corporation.

The existing business of the Corporation is carried on through the Partnership and through CPEUS. The Partnership holds all of the Corporation's Canadian operating assets and CPEUS holds all of the Corporation's U.S. operating assets.

### CPHI

CPHI is a wholly-owned subsidiary of the Corporation. CPHI is a partner of the Partnership.

**CPLux**

CPLux is a wholly-owned indirect subsidiary of the Corporation.

**CPUSH**

Crescent Point U.S. Holdings Corp. is a wholly-owned direct subsidiary of the Corporation.

**CPEUS**

Crescent Point Energy U.S. Corp. is a wholly-owned indirect subsidiary of the Corporation. CPEUS holds the Corporation's operating assets in the United States.

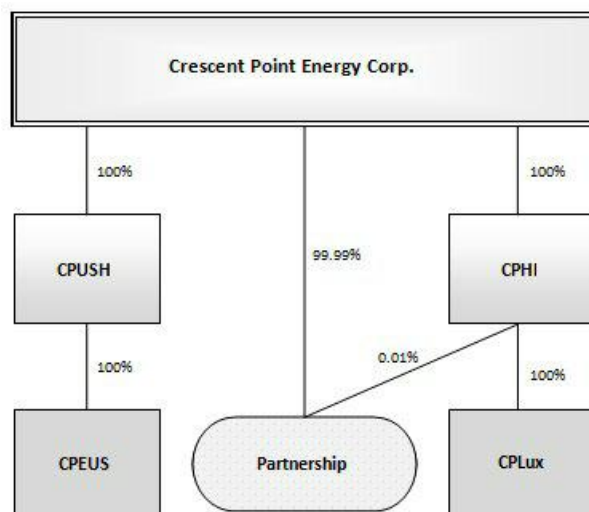
**Relationships**

The following table provides the name, the percentage of voting securities owned by the Corporation and the jurisdiction of incorporation, continuance or formation of the Corporation's material subsidiaries as at the date hereof.

	<u>Percentage of Voting Securities (Directly or Indirectly)</u>	<u>Jurisdiction of Incorporation/Formation</u>
CPI	100%	Alberta
Partnership	100%	Alberta
CPUSH	100%	Nevada
CPEUS	100%	Delaware
CPLux	100%	Luxembourg

## Organizational Structure of the Corporation

The following diagram describes the inter-corporate relationships among the Corporation and its material direct and indirect subsidiaries described above as at March 4, 2020. Reference should be made to the appropriate sections of this AIF for a complete description of the structure of the Corporation.



## GENERAL DEVELOPMENT OF THE BUSINESS OF THE CORPORATION

### History

The following is a description of the general development of the business of Crescent Point over the past three years.

#### 2017

In the first quarter of 2017, Crescent Point completed the acquisition of approximately 8,500 net acres in North Dakota for total cash consideration of US\$100.0 million. The acquired lands were contiguous to the Corporation's current acreage.

Crescent Point also acquired approximately 80,000 net acres of undeveloped land in the Uinta Basin in the second quarter of 2017, for total cash consideration of US\$72.5 million.

In the second quarter of 2017, the Corporation sold 1,100 boe/d of non-operated conventional assets in Manitoba for total cash consideration of \$93.2 million.

On May 24, 2017, Ted Goldthorpe was elected as a director of the Corporation. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

On June 26, 2017, Crescent Point renewed its unsecured, covenant-based credit facilities totaling \$3.6 billion. The renewal extended the maturity date of the credit facilities to June 10, 2020. See "*Additional Information Respecting Crescent Point - Long-Term Debt*".

During the third quarter of 2017, the Corporation completed or entered into agreements to dispose of non-core assets representing approximately 3,000 boe/d for total value of over \$190 million.

In the fourth quarter of 2017, Crescent Point entered into agreements to dispose of non-core assets for total value of approximately \$40 million.

#### 2018

In the second quarter of 2018, Crescent Point completed the disposition of non-core assets mostly in southeast Saskatchewan, for proceeds of approximately \$280 million. The assets sold represented operated and non-operated production of approximately 4,800 boe/d.

Early in the second quarter of 2018, the Corporation completed a private placement of senior unsecured, guaranteed notes for total gross proceeds of US\$143.5 million and CDN\$80.0 million. Three separate series of notes were issued as part of the private placement, with maturities ranging from five to seven years and interest rates ranging from 3.58% to 3.98%. Proceeds from the issuance of the notes were used to repay a portion of the Corporation's outstanding bank debt and other senior guaranteed notes with near-term maturities.

On May 4, 2018, François Langlois was elected as a new director of the Corporation. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

On May 29, 2018, Scott Saxberg stepped down as President and Chief Executive Officer of Crescent Point, and Craig Bryksa was appointed interim President and Chief Executive Officer and to the Board. Mr. Bryksa was subsequently appointed as Crescent Point's President and Chief Executive Officer on September 5, 2018.

On June 19, 2018, Neil Smith, Chief Operating Officer, stepped down as an officer of the Corporation, and Ryan Gritzfeldt was promoted from Vice President, Marketing and Innovation to the position of Chief Operating Officer.

On June 22, 2018, Crescent Point renewed its unsecured credit facilities totaling \$3.6 billion with a new maturity date of June 10, 2021.

On September 5, 2018, Robert Heinemann was appointed as the new Chairman of the Board of Directors, replacing Peter Bannister, who has announced his intention to retire from the Board at the Corporation's 2019 annual meeting of shareholders.

#### 2019

On January 25, 2019, the Corporation commenced its NCIB to purchase, for cancellation, up to 38,424,678 Common Shares, or seven percent of the Corporation's public float, as at January 14, 2019. The NCIB expired on January 24, 2020. 26,238,600 Common Shares were purchased under the NCIB.

On February 19, 2019, Crescent Point announced the appointment of John P. Dielwart to the Board, effective March 7, 2019. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

On June 14, 2019, James Craddock and Jennifer Koury were appointed to the Board. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

In September 2019, Crescent Point disposed of certain conventional assets in southeast Saskatchewan for consideration of \$196.9 million, representing approximately 7,000 boe/d of production.

On October 18, 2019, Crescent Point sold the entirety of its Utah assets for approximately \$700 million.

On October 25, 2019, Crescent Point elected to reduce its covenant-based credit facilities from \$3.6 billion to \$3.0 billion and extended the maturity dates to October 2023.

On October 30, 2019, Barbara Munroe was appointed as the new Chair of the Board, replacing Robert Heinemann, who retired from the Board.

2020

On January 20, 2020, Crescent Point sold certain associated gas infrastructure assets in Saskatchewan to Steel Reef Infrastructure Corp. ("**Steel Reef**") for total cash consideration of \$500 million. Through the sale of these assets, Crescent Point monetized nine natural gas gathering and processing facilities and two gas sales pipelines currently in operation within Saskatchewan. These gas processing facilities and associated sales gas lines have a total throughput capacity of more than 90 MMcf/d. The assets did not include any oil-related infrastructure. Concurrently, Crescent Point entered into certain long-term take-or-pay commitments with Steel Reef in exchange for Steel Reef granting Crescent Point processing rights at the facilities.

## DESCRIPTION OF OUR BUSINESS

### General

The Corporation is an oil and gas exploration, development and production company. The Corporation is a conventional oil and gas producer with assets strategically focused in properties comprised of high quality, long life, operated, light and medium crude oil and natural gas reserves in Western Canada and the United States. The primary assets of the Corporation are currently its interest in the Partnership, shares in CPHI, shares in CPUSH and, indirectly, shares in CPEUS.

The crude oil and natural gas properties and related assets generating income for the benefit of the Corporation are located in the provinces of Saskatchewan, Alberta, British Columbia and Manitoba and in the states of North Dakota and Montana. The properties and assets consist of producing crude oil and natural gas reserves and Proved plus Probable (as defined herein) crude oil and natural gas reserves not yet on production, and land holdings.

We pay regular cash dividends to Shareholders from our net cash flow in accordance with our dividend policy. Our primary sources of cash flow are distributions from the Partnership. During the year ended December 31, 2019, we paid quarterly dividends of \$0.01 per Common Share. See "*Dividends*".

### Strategy

We strive to enhance shareholder returns by cost effectively developing a focused asset base in a responsible and sustainable manner. Through the development of our assets, we aim to create sustainable, profitable and returns-based growth in reserves, production and cash flow.

We strategically develop our properties through detailed technical analysis including reservoir characteristics, petroleum initially in place, recovery factors and the applicability of enhanced recovery techniques. Our development strategies include, infill and step-out wells, multi-stage fracture stimulation of horizontal wells, re-completion of existing wells and secondary recovery techniques such as waterflood programs.

### Risk Management and Marketing

Factors outside our control impact, to varying degrees, the prices we receive for production. These include, but are not limited to:

- (a) world market forces, including world supply and consumption levels and the ability of OPEC and others to set and maintain production levels and prices for crude oil;
- (b) political conditions, including the risk of hostilities in the Middle East, South America and other regions throughout the world;
- (c) availability, proximity and capacity of take-away alternatives, including oil and gas gathering systems, pipelines, processing facilities, railcars and railcar loading facilities;
- (d) increases or decreases in crude oil differentials and their implications for prices received by us;
- (e) the impact of changes in the exchange rate between Canadian and U.S. dollars on prices received by us for our crude oil and natural gas;

- (f) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the prices of crude oil and natural gas;
- (g) global and domestic economic and weather conditions and changes in demand as a result of outbreaks or other health emergencies;
- (h) price and availability of alternative fuels;
- (i) the effect of energy conservation measures and government regulations; and
- (j) U.S. and Canada tax policy.

Fluctuations in commodity prices, differentials and foreign exchange and interest rates, among other factors, are outside of our control and yet can have a significant impact on the level of cash we have available for payment of dividends to Shareholders.

To mitigate a portion of these risks, we actively initiate, manage and disclose the effects of our hedging activities. Our strategy for crude oil and natural gas production is to hedge up to 65%, or as otherwise approved by the Board of Directors, of our net of royalty production up to a rolling three and a half year basis, at the discretion of management. The Corporation also uses a combination of financial derivatives and fixed-differential physical contracts to hedge price differentials. For differential hedging, Crescent Point's risk management program allows for hedging a forward profile of up to three and a half years, and up to 35% net of royalty production. All hedging activities are governed by our Risk Management and Counterparty Credit Policy and are regularly reviewed by the Board of Directors.

As part of our risk management program, benchmark oil prices are hedged using financial WTI-based instruments transacted in Canadian and U.S. dollars and benchmark natural gas prices are hedged using financial AECO-based instruments transacted in Canadian dollars. Total financial oil and gas hedges in 2019 amounted to approximately 47% of annual production, net of royalties, consisting of approximately 50% of annual liquids production and approximately 22% of annual natural gas production, net of royalties. The Corporation recorded a realized derivative loss on crude oil and natural gas hedge contracts of \$43.4 million in 2019.

Crescent Point also enters into physical delivery and derivative WTI price differential contracts which manage the spread between US\$ WTI and various stream prices on a portion of its production. The Corporation manages physical delivery contracts on a month-to-month spot and term contract basis. From January to December 2019, approximately 18,300 bbls/d of liquids production was contracted with fixed price differentials off WTI.

Refer to the annual financial statements for our commitments under all hedging agreements as at December 31, 2019.

In addition to hedging benchmark crude oil and natural gas prices with financial instruments, we also mitigate crude oil basis risk by delivering a portion of our crude oil production into diversified refinery markets using rail transportation. Crescent Point operates two railcar loading facilities, serving its key producing areas of southeast Saskatchewan and southwest Saskatchewan. Crude oil volumes loaded at these facilities are sold at the loading facilities and our buyers are responsible for providing railcars and managing transportation logistics from that point until delivery at the refinery gate. By utilizing rail transportation, we have been able to access refining markets over the past several years that are not pipeline connected to western Canada, which helps diversify price and market risk.

We mitigate credit risk by having a well-diversified marketing portfolio for crude oil and natural gas. Credit risk associated with the Corporation's portfolio of physical crude oil and natural gas sales and with the Corporation's commodity hedging portfolio is managed by Crescent Point's Risk Management Committee and is governed by a board-approved Risk Management and Counterparty Credit Policy that is reviewed annually by the Board of Directors. The Policy requires annual credit reviews of all trade counterparties. Credit limits are required to be set for all trade counterparties, which are based on either a fixed dollar amount which is set annually, at a minimum, or a percentage of the Corporation's portfolio calculated monthly. Crescent Point utilizes a diversified approach in both its physical sales portfolio and its financial hedging portfolio. The physical sales portfolio consists of 107 purchasers and its financial hedging portfolio consists of 15 counterparties. The Corporation's portfolio of counterparty exposures is monitored on a monthly basis.

To further mitigate credit risk associated with its physical sales portfolio, Crescent Point obtains financial assurances such as parental guarantees, letters of credit and third party credit insurance. Including these assurances, approximately 95% of the Corporation's oil and gas sales are with entities considered investment grade.

### Revenue Sources

Our crude oil and natural gas volumes are sold in the United States, Saskatchewan, Alberta, Manitoba and British Columbia. Approximately 72% of our liquids volumes are sold in Saskatchewan, 22% in the U.S., 6% in Alberta, and less than 1% in Manitoba and British Columbia. Approximately 62% of our natural gas volumes are sold in Saskatchewan, 25% in the United States, 12% in Alberta and less than 1% in Manitoba and British Columbia.

For 2019, our commodity production mix was approximately 91% crude oil and NGLs and 9% natural gas.

The following table summarizes our revenue sources by product before hedging and royalties:

For Year Ended	Crude Oil and NGLs	Natural Gas
2019	97%	3%
2018	98%	2%
2017	97%	3%

### Competition

We actively compete for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than we do. Our competitors include major integrated oil and natural gas companies, numerous other independent oil and natural gas entities and individual producers and operators. Similarly, we face a competitive market when we attempt to divest of non-core assets.

Certain of our customers and potential customers are themselves exploring for crude oil and natural gas, and the results of such exploration efforts could affect our ability to sell or supply crude oil or natural gas to these customers in the future. Our ability to successfully bid on and acquire additional property rights, divest property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers is dependent upon developing and maintaining close working relationships with our industry partners and joint operators, our ability to select and evaluate suitable properties, and our ability to consummate transactions in a highly competitive environment.

### Seasonal Factors

The production of crude oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

### Personnel

As of December 31, 2019, the Corporation had 864 permanent employees: 393 employees at the head office in Calgary, 50 employees at the Denver office, 407 field employees in Canada and 14 field employees in the U.S.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

### Disclosure of Reserves Data

In accordance with NI 51-101, the reserves data of the Corporation set forth below (the "**Reserves Data**") is based upon evaluations conducted by GLJ and Sproule with an effective date of December 31, 2019, and contained in the consolidated report of GLJ dated February 14, 2020 (the "**Crescent Point Reserve Report**"). The tables below are a combined summary

of our crude oil, NGL and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Crescent Point Reserve Report based on Sproule's December 31, 2019 forecast price and cost assumptions. GLJ evaluated approximately 40% of the assigned total Proved plus Probable reserves and 29% of the total Proved plus Probable value discounted at 10%. Sproule evaluated approximately 60% of the assigned total Proved plus Probable reserves and 71% of the total Proved plus Probable value discounted at 10%. Sproule evaluated a majority of the southeast Saskatchewan assets including the Viewfield Bakken and Flat Lake Torquay properties, as well as southwest Saskatchewan assets including the Shaunavon and Saskatchewan Viking properties. Sproule evaluated their portion of the reserves using the Sproule forecast price and cost escalation assumptions. GLJ evaluated the Corporation's Alberta and British Columbia assets, as well as a portion of the assets in southeast Saskatchewan. GLJ also performed the evaluation of the Corporation's U.S. assets in North Dakota and Montana. These assets were all evaluated using the Sproule forecast price and cost escalation assumptions. GLJ prepared the total Crescent Point Reserve Report by consolidating the GLJ Canadian and U.S. evaluated properties with the Sproule evaluation using the Sproule pricing and cost escalation assumptions. The tables below summarize the data contained in the Crescent Point Reserve Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

**The net present value of future net revenue attributable to our reserves is stated without provision for interest costs, and general and administrative costs, but after providing for estimated royalties, production costs, capital taxes, development costs, other income, future capital expenditures, projected carbon emission costs, and well and location abandonment costs for those entities assigned reserves by GLJ and Sproule. The reserve assessments also include costs associated with wells that have not been assessed values in the reserve reports and facilities and gathering systems associated with the ongoing production for the Corporation. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to our reserves estimated by GLJ and Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of our crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.**

The Corporation continuously monitors and reviews legislation concerning greenhouse gas emissions and the impact on operations. New legislation that was adopted in 2019 has allowed Crescent Point to reduce anticipated negative financial impacts from the production of oil and gas products through the Output-Based Performance Standard ("OBPS") program in Saskatchewan and the Technology Innovation and Emission Reduction ("TIER") program in Alberta. The anticipated negative financial impact of carbon emission costs to Total Proved plus Probable reserves evaluation as of December 31, 2019 as a result of the implementation of these new programs is \$9.5 MM discounted at 10% before tax, with no impact on reserve level bookings.

The Crescent Point Reserve Report is based on certain factual data supplied by Crescent Point as well as GLJ and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to Crescent Point's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to GLJ and Sproule, and were accepted without any further investigation. GLJ and Sproule accepted this data as presented and neither title searches nor field inspections were conducted.



**Reserves Data – Forecast Prices and Costs**

*Summary of Oil and Gas Reserves<sup>(1)</sup>*

Reserves Category	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil		Natural Gas Liquids		Shale Gas		Conventional Natural Gas		Total	
	Company Gross (Mbbbls)	Company Net (Mbbbls)	Company Gross (Mbbbls)	Company Net (Mbbbls)	Company Gross (Mbbbls)	Company Net (Mbbbls)	Company Gross (Mbbbls)	Company Net (Mbbbls)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (MMcf)	Company Net (MMcf)	Company Gross (Mboe)	Company Net (Mboe)
<b>Proved Developed Producing</b>														
Canada	71,484	63,986	24,175	20,066	116,743	109,581	36,450	33,775	91,829	85,575	60,040	55,970	274,163	250,998
United States	—	—	—	—	21,059	17,057	6,335	5,131	19,664	15,926	—	—	30,672	24,843
<b>Total</b>	<b>71,484</b>	<b>63,986</b>	<b>24,175</b>	<b>20,066</b>	<b>137,803</b>	<b>126,638</b>	<b>42,785</b>	<b>38,906</b>	<b>111,492</b>	<b>101,501</b>	<b>60,040</b>	<b>55,970</b>	<b>304,836</b>	<b>275,841</b>
<b>Proved Developed Non-Producing</b>														
Canada	1,341	1,246	1,979	1,731	1,313	1,209	618	570	1,216	1,060	1,297	1,073	5,669	5,111
United States	—	—	—	—	6	5	—	—	3	2	—	—	6	5
<b>Total</b>	<b>1,341</b>	<b>1,246</b>	<b>1,979</b>	<b>1,731</b>	<b>1,318</b>	<b>1,213</b>	<b>618</b>	<b>570</b>	<b>1,219</b>	<b>1,062</b>	<b>1,297</b>	<b>1,073</b>	<b>5,675</b>	<b>5,116</b>
<b>Proved Undeveloped</b>														
Canada	28,122	26,013	1,645	1,419	58,096	55,040	13,239	12,365	45,407	41,860	10,750	9,743	110,462	103,439
United States	—	—	—	—	37,825	30,638	6,421	5,201	21,206	17,177	—	—	47,780	38,702
<b>Total</b>	<b>28,122</b>	<b>26,013</b>	<b>1,645</b>	<b>1,419</b>	<b>95,922</b>	<b>85,679</b>	<b>19,659</b>	<b>17,566</b>	<b>66,614</b>	<b>59,038</b>	<b>10,750</b>	<b>9,743</b>	<b>158,242</b>	<b>142,141</b>
<b>Total Proved</b>														
Canada	100,947	91,245	27,799	23,216	176,152	165,831	50,306	46,710	138,452	128,496	72,086	66,787	390,294	359,548
United States	—	—	—	—	58,890	47,700	12,756	10,332	40,873	33,105	—	—	78,459	63,550
<b>Total</b>	<b>100,947</b>	<b>91,245</b>	<b>27,799</b>	<b>23,216</b>	<b>235,043</b>	<b>213,531</b>	<b>63,062</b>	<b>57,042</b>	<b>179,325</b>	<b>161,601</b>	<b>72,086</b>	<b>66,787</b>	<b>468,753</b>	<b>423,098</b>
<b>Total Probable</b>														
Canada	58,348	52,860	6,894	5,508	112,932	105,681	26,302	24,511	80,222	74,407	33,640	31,003	223,452	206,129
United States	—	—	—	—	37,120	30,086	7,013	5,684	22,942	18,598	—	—	47,956	38,870
<b>Total</b>	<b>58,348</b>	<b>52,860</b>	<b>6,894</b>	<b>5,508</b>	<b>150,052</b>	<b>135,767</b>	<b>33,315</b>	<b>30,195</b>	<b>103,163</b>	<b>93,005</b>	<b>33,640</b>	<b>31,003</b>	<b>271,409</b>	<b>244,998</b>
<b>Total Proved Plus Probable</b>														
Canada	159,295	144,104	34,693	28,724	289,084	271,512	76,608	71,221	218,674	202,903	105,726	97,790	613,747	565,677
United States	—	—	—	—	96,010	77,786	19,769	16,016	63,815	51,703	—	—	126,415	102,419
<b>Total</b>	<b>159,295</b>	<b>144,104</b>	<b>34,693</b>	<b>28,724</b>	<b>385,094</b>	<b>349,298</b>	<b>96,377</b>	<b>87,237</b>	<b>282,488</b>	<b>254,606</b>	<b>105,726</b>	<b>97,790</b>	<b>740,161</b>	<b>668,096</b>

**Note:**

(1) Numbers may not add due to rounding.

Net Present Value of Future Net Revenue of Oil and Gas Reserves<sup>(1)</sup>

Reserves Category	Before Income Taxes Discounted at (%/year)						After Income Taxes Discounted at (%/year)					
	0% (MM\$)	5% (MM\$)	8% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)	0% (MM\$)	5% (MM\$)	8% (MM\$)	10% (MM\$)	15% (MM\$)	20% (MM\$)
<b>Proved Developed Producing</b>												
Canada	8,406	6,697	5,922	5,500	4,681	4,096	8,093	6,526	5,801	5,402	4,624	4,060
United States	977	735	640	590	497	433	944	717	627	579	490	428
<b>Total</b>	<b>9,383</b>	<b>7,432</b>	<b>6,563</b>	<b>6,090</b>	<b>5,179</b>	<b>4,529</b>	<b>9,037</b>	<b>7,242</b>	<b>6,428</b>	<b>5,982</b>	<b>5,114</b>	<b>4,489</b>
<b>Proved Developed Non-Producing</b>												
Canada	257	177	151	138	115	98	196	140	122	114	99	88
United States	—	—	—	—	—	—	—	—	—	—	—	—
<b>Total</b>	<b>257</b>	<b>177</b>	<b>151</b>	<b>138</b>	<b>115</b>	<b>99</b>	<b>197</b>	<b>140</b>	<b>123</b>	<b>114</b>	<b>99</b>	<b>88</b>
<b>Proved Undeveloped</b>												
Canada	2,623	1,808	1,461	1,272	911	659	1,896	1,309	1,054	916	648	461
United States	772	368	226	156	37	(33)	709	334	201	136	25	(41)
<b>Total</b>	<b>3,395</b>	<b>2,176</b>	<b>1,687</b>	<b>1,428</b>	<b>948</b>	<b>626</b>	<b>2,605</b>	<b>1,643</b>	<b>1,256</b>	<b>1,052</b>	<b>673</b>	<b>420</b>
<b>Total Proved</b>												
Canada	11,287	8,682	7,535	6,910	5,707	4,854	10,185	7,974	6,978	6,432	5,371	4,609
United States	1,749	1,103	866	746	534	400	1,653	1,051	828	716	515	388
<b>Total</b>	<b>13,036</b>	<b>9,785</b>	<b>8,401</b>	<b>7,657</b>	<b>6,242</b>	<b>5,254</b>	<b>11,838</b>	<b>9,025</b>	<b>7,806</b>	<b>7,148</b>	<b>5,886</b>	<b>4,997</b>
<b>Total Probable</b>												
Canada	9,319	5,298	4,082	3,510	2,549	1,965	6,898	3,903	2,999	2,576	1,869	1,444
United States	1,918	999	738	621	432	324	1,648	891	668	566	400	302
<b>Total</b>	<b>11,238</b>	<b>6,297</b>	<b>4,820</b>	<b>4,130</b>	<b>2,981</b>	<b>2,289</b>	<b>8,546</b>	<b>4,794</b>	<b>3,667</b>	<b>3,142</b>	<b>2,269</b>	<b>1,746</b>
<b>Total Proved Plus Probable</b>												
Canada	20,606	13,980	11,617	10,420	8,256	6,819	17,083	11,877	9,977	9,008	7,240	6,053
United States	3,667	2,102	1,604	1,367	967	724	3,301	1,941	1,496	1,282	915	690
<b>Total</b>	<b>24,273</b>	<b>16,082</b>	<b>13,221</b>	<b>11,787</b>	<b>9,223</b>	<b>7,543</b>	<b>20,384</b>	<b>13,818</b>	<b>11,474</b>	<b>10,289</b>	<b>8,155</b>	<b>6,743</b>

**Note:**

(1) Numbers may not add due to rounding.

*Additional Information Concerning Future Net Revenue – (Undiscounted)<sup>(1)</sup>*

<b>Reserves Category</b>	<b>Revenue (MM\$)</b>	<b>Royalties &amp; Burdens<sup>(2)</sup> (MM\$)</b>	<b>Operating Costs (MM\$)</b>	<b>Development Costs (MM\$)</b>	<b>Abandonment and Reclamation Costs<sup>(3)</sup> (MM\$)</b>	<b>Future Net Revenue Before Income Taxes (MM\$)</b>	<b>Income Tax (MM\$)</b>	<b>Future Net Revenue After Income Taxes (MM\$)</b>
<b>Proved</b>								
Canada	27,873	2,770	9,657	2,393	1,767	11,287	1,102	10,185
United States	5,938	1,559	1,546	1,048	36	1,749	96	1,653
<b>Total</b>	<b>33,811</b>	<b>4,328</b>	<b>11,203</b>	<b>3,441</b>	<b>1,803</b>	<b>13,036</b>	<b>1,197</b>	<b>11,838</b>
<b>Proved Plus Probable</b>								
Canada	46,465	4,508	15,515	3,862	1,974	20,606	3,523	17,083
United States	10,331	2,714	2,671	1,232	47	3,667	366	3,301
<b>Total</b>	<b>56,796</b>	<b>7,222</b>	<b>18,185</b>	<b>5,094</b>	<b>2,021</b>	<b>24,273</b>	<b>3,889</b>	<b>20,384</b>

**Notes:**

(1) Numbers may not add due to rounding.

(2) Saskatchewan Capital Resource Surcharge, as well as Ad Valorem, and Severance payable in the United States have been included under the royalties and burdens column.

(3) Abandonment and Reclamation costs now include active costs from wells and locations included in the Crescent Point Reserve Report as well as inactive costs including suspended wells, pipelines and facilities, as specified in COGEH update of October 2019.

In 2018, the Crescent Point Reserve Report included abandonment and reclamation costs for active wells and locations only. As recommended in the October 2019 COGEH updated guidance, the Corporation has now also included abandonment, decommissioning and reclamation costs for all inactive assets including non-producing and suspended wells, facilities and pipelines. The impact on the Crescent Point Reserve Report from these additional burdens on total Proved plus Probable reserves is estimated at \$261 million of value discounted at 10%, which will differ from the discounted values carried in our financial reporting, due to differences in abandonment activity timing and different inflation and discount values.

Future Net Revenue by Production Type<sup>(1)</sup>

	Future Net Revenue Before Income Taxes <sup>(6)</sup> (Discounted at 10% per year)	Percentage	Unit Value	
	(MMS)	(%)	(\$/boe)	(\$/Mcfe)
<b>Proved</b>				
<b>CANADA</b>				
Light and Medium Crude Oil <sup>(2)</sup>	1,916	27.7	18.41	3.07
Heavy Crude Oil <sup>(2)</sup>	376	5.4	16.09	2.68
Tight Oil <sup>(4)</sup>	4,585	66.3	20.71	3.45
Natural Gas Liquids	—	—	—	—
Shale Gas <sup>(5)</sup>	—	—	—	—
Conventional Natural Gas <sup>(3)</sup>	33	0.5	3.11	0.52
<b>Total Canada</b>	<b>6,910</b>	<b>100</b>	<b>19.22</b>	<b>3.20</b>
<b>UNITED STATES</b>				
Light and Medium Crude Oil <sup>(2)</sup>	—	—	—	—
Heavy Crude Oil <sup>(2)</sup>	—	—	—	—
Tight Oil <sup>(4)</sup>	746	100	11.74	1.96
Natural Gas Liquids	—	—	—	—
Shale Gas <sup>(3)</sup>	—	—	—	—
Conventional Natural Gas <sup>(3)</sup>	—	—	—	—
<b>Total United States</b>	<b>746</b>	<b>100</b>	<b>11.74</b>	<b>1.96</b>
<b>TOTAL</b>				
Light and Medium Crude Oil <sup>(2)</sup>	1,916	25.0	18.41	3.07
Heavy Crude Oil <sup>(2)</sup>	376	4.9	16.09	2.68
Tight Oil <sup>(4)</sup>	5,331	69.6	18.71	3.12
Natural Gas Liquids	—	—	—	—
Shale Gas <sup>(3)(5)</sup>	—	—	—	—
Conventional Natural Gas <sup>(3)</sup>	33	0.4	3.11	0.52
<b>Total Proved</b>	<b>7,657</b>	<b>100</b>	<b>18.10</b>	<b>3.02</b>

**Notes:**

- (1) Numbers may not add due to rounding.
- (2) Including solution gas and other by-products.
- (3) Including by-products, but excluding solution gas.
- (4) Including solution gas (categorized as "Shale Gas") and other by-products.
- (5) Volumes of Shale Natural Gas have been included in "Tight Oil" as it is solution gas relating to oil production.
- (6) Other company revenue and costs not related to a specific production type have been allocated proportionately to production types. Unit values are based on Company Net Reserves.

	Future Net Revenue Before Income Taxes <sup>(6)</sup> (Discounted at 10% per year)	Percentage	Unit Value	
	(MM\$)	(%)	(\$/boe)	(\$/Mcf)
<b>Proved Plus Probable</b>				
<b>CANADA</b>				
Light and Medium Crude Oil <sup>(2)</sup>	2,961	28.4	17.70	2.95
Heavy Crude Oil <sup>(1)</sup>	456	4.4	15.76	2.63
Tight Oil <sup>(4)</sup>	6,965	66.8	19.53	3.26
Natural Gas Liquids	—	—	—	—
Shale Gas <sup>(5)</sup>	—	—	—	—
Conventional Natural Gas <sup>(3)</sup>	39	0.4	3.01	0.50
<b>Total Canada</b>	<b>10,420</b>	<b>100</b>	<b>18.42</b>	<b>3.07</b>
<b>UNITED STATES</b>				
Light and Medium Crude Oil <sup>(2)</sup>	—	—	—	—
Heavy Crude Oil <sup>(2)</sup>	—	—	—	—
Tight Oil <sup>(4)</sup>	1,367	100	13.35	2.22
Natural Gas Liquids	—	—	—	—
Shale Gas <sup>(3)</sup>	—	—	—	—
Conventional Natural Gas <sup>(3)</sup>	—	—	—	—
<b>Total United States</b>	<b>1,367</b>	<b>100</b>	<b>13.35</b>	<b>2.22</b>
<b>TOTAL</b>				
Light and Medium Crude Oil <sup>(2)</sup>	2,961	25.1	17.70	2.95
Heavy Crude Oil <sup>(2)</sup>	456	3.9	15.76	2.63
Tight Oil <sup>(4)</sup>	8,332	70.7	18.15	3.03
Natural Gas Liquids	—	—	—	—
Shale Gas <sup>(3)(5)</sup>	—	—	—	—
Conventional Natural Gas <sup>(3)</sup>	39	0.3	3.01	0.50
<b>Total Proved Plus Probable</b>	<b>11,787</b>	<b>100</b>	<b>17.64</b>	<b>2.94</b>

**Notes:**

- (1) Numbers may not add due to rounding.
- (2) Including solution gas and other by-products.
- (3) Including by-products, but excluding solution gas.
- (4) Including solution gas (categorized as "Shale Gas") and other by-products.
- (5) Volumes of Shale Natural Gas have been included in "Tight Oil" as it is solution gas relating to oil production.
- (6) Other company revenue and costs not related to a specific production type have been allocated proportionately to production types. Unit values are based on Company Net Reserves.

**Notes and Definitions**

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this AIF, the following notes and other definitions are applicable.

**Reserve Categories**

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of Proved and Probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

- (a) **"Reserves"** are estimated remaining economic quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.
- (b) **"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.
- (c) **"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.
- (d) **"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.
- (e) **"Undeveloped"** reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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 category (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.
- (f) **"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.

#### *Levels of Certainty for Reported Reserves*

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved reserves; and
- At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

#### *Additional Definitions*

The following terms, used in the preparation of the Crescent Point Reserve Report and this AIF, have the following meanings:

- (a) **"associated gas"** means the gas cap overlying a crude oil accumulation in a reservoir.

- (b) "**crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain small amounts of sulphur and other non-hydrocarbons, that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. It does not include liquids obtained from the processing of natural gas.
- (c) "**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
- (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
  - (ii) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
  - (iii) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds measuring devices and production storage, natural gas cycling and processing plants, and central utility and waste disposal system; and
  - (iv) provide improved recovery systems.
- (d) "**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
- (e) "**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");
  - (ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
  - (iii) dry hole contributions and bottom hole contributions;
  - (iv) costs of drilling and equipping exploratory wells; and
  - (v) costs of drilling exploratory type stratigraphic test wells.
- (f) "**exploratory well**" means a well that is not a development well, a service well or a development type stratigraphic test well.
- (g) "**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature"

and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

- (h) **"future prices and costs"** means future prices and costs that are:
  - (i) generally accepted as being a reasonable outlook of the future;
  - (ii) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation 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 (i).
- (i) **"future income tax expenses"** means future income tax expenses estimated (generally, year-by-year):
  - (i) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
  - (ii) without deducting estimated future costs that are not deductible in computing taxable income;
  - (iii) taking into account estimated tax credits and allowances (for example, royalty tax credits); and
  - (iv) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year end statutory tax rates, taking into account future tax rates already legislated.
- (j) **"future net revenue"** means the estimated net amount to be received with respect to the anticipated development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using future prices and costs.
- (k) **"gross"** means:
  - (i) in relation to the Corporation's interest in production or reserves, its "company gross reserves", which are its working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of the Corporation;
  - (ii) in relation to wells, the total number of wells in which the Corporation has an interest; and
  - (iii) in relation to properties, the total area of properties in which the Corporation has an interest.
- (l) **"natural gas"** means a naturally occurring mixture of hydrocarbon gases and other gases.
- (m) **"natural gas liquids"** means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.
- (n) **"net"** means:
  - (i) in relation to the Corporation's interest in production or reserves, its working interest (operated or non-operated) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
  - (ii) in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and
  - (iii) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.
- (o) **"non-associated gas"** means an accumulation of natural gas in a reservoir where there is no crude oil.



- (p) "**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities as well as other costs of operating and maintaining those wells and related equipment and facilities.
- (q) "**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.
- (r) "**property**" includes:
- (i) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
  - (ii) royalty interests, production payments payable in oil or gas, and other non-operated interests in properties operated by others; and
  - (iii) an agreement with a foreign government or authority under which the Corporation participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).
- A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.
- (s) "**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:
- (i) costs of lease bonuses and options to purchase or lease a property;
  - (ii) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and
  - (iii) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.
- (t) "**proved property**" means a property or part of a property to which reserves have been specifically attributed.
- (u) "**reservoir**" means a subsurface rock unit that contains an accumulation of petroleum.
- (v) "**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.
- (w) "**solution gas**" means natural gas dissolved in crude oil.
- (x) "**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) "exploratory type" if not drilled into a proved property; or (ii) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".
- (y) "**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.
- (z) "**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

- (aa) **"well abandonment and reclamation costs"** means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system and remediating and reclaiming the site to original conditions. They do not include costs of abandoning the gathering system.

### Pricing Assumptions – Forecast Prices and Costs

GLJ and Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2019 in estimating our reserves data using forecast prices and costs.

Year	Conventional Natural Gas		Crude Oil		NGLs			Operating Cost Inflation Rate (%/yr)	Capital Cost Inflation Rate (%/yr)	Exchange Rate (\$US/\$Cdn)
	Henry Hub NYMEX (\$US/MMBTU)	AECO/NIT Spot (\$Cdn/MMBTU)	WTI at Cushing Oklahoma (\$US/bbl)	Edmonton (\$Cdn/bbl)	Pentanes Plus Edmonton (\$Cdn/bbl)	Butanes Edmonton (\$Cdn/bbl)	Propane Edmonton (\$Cdn/bbl)			
Forecast										
2020	2.80	2.04	61.00	73.84	76.32	37.72	25.07	0.0%	0.0%	0.760
2021	3.00	2.27	65.00	78.51	80.52	43.90	31.84	1.0%	1.0%	0.770
2022	3.25	2.81	67.00	78.73	80.00	47.74	32.43	2.0%	2.0%	0.800
2023	3.32	2.89	68.34	80.30	81.68	48.69	33.26	2.0%	2.0%	0.800
2024	3.38	2.98	69.71	81.91	83.38	49.67	34.12	2.0%	2.0%	0.800
2025	3.45	3.06	71.10	83.54	85.13	50.66	34.99	2.0%	2.0%	0.800
2026	3.52	3.15	72.52	85.21	86.90	51.67	35.88	2.0%	2.0%	0.800
2027	3.59	3.24	73.97	86.92	88.72	52.71	36.78	2.0%	2.0%	0.800
2028	3.66	3.33	75.45	88.66	90.57	53.76	37.71	2.0%	2.0%	0.800
2029	3.73	3.42	76.96	90.43	92.45	54.84	38.65	2.0%	2.0%	0.800
2030	3.81	3.51	78.50	92.24	94.38	55.93	39.61	2.0%	2.0%	0.800
2031+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0%	2.0%	0.800

For the year ended December 31, 2019, the average realized sales prices before hedging were \$66.50/bbl for light and medium crude oil, \$60.95/bbl for heavy crude oil, \$67.67/bbl for tight oil, \$19.94/bbl for NGLs, \$2.87/mcf for shale gas and \$2.29/mcf for conventional natural gas.

### Reconciliations of Changes in Reserves<sup>(1)</sup>

The following table sets forth a reconciliation of the Corporation's Company Gross reserves by total Proved, total Probable and total Proved plus Probable reserves as at December 31, 2019 against such reserves as at December 31, 2018 based on forecast price and cost assumptions.

CANADA	Light and Medium Crude Oil (Mbbbls)			Heavy Crude Oil (Mbbbls)			Tight Oil (Mbbbls)			Natural Gas Liquids (Mbbbls)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
<b>December 31, 2018</b>	127,356	71,928	199,284	29,015	7,903	36,918	219,734	130,667	350,400	59,824	31,789	91,613
Discoveries	85	29	114	—	—	—	494	171	664	27	9	36
Extensions and Improved Recovery <sup>(2)</sup>	3,658	2,016	5,674	133	10	143	11,669	8,865	20,534	1,282	875	2,156
Technical Revisions <sup>(4)</sup>	(638)	(5,633)	(6,270)	670	(951)	(281)	(21,578)	(20,512)	(42,090)	(1,885)	(4,122)	(6,007)
Acquisitions	2,403	590	2,993	—	—	—	2	47	49	—	17	17
Dispositions <sup>(5)</sup>	(18,827)	(9,959)	(28,786)	—	—	—	(9,186)	(6,707)	(15,893)	(2,321)	(2,080)	(4,401)
Economic Factors	(2,107)	(622)	(2,729)	(285)	(69)	(354)	(1,761)	402	(1,360)	(691)	(186)	(877)
Production <sup>(7)</sup>	(10,984)	—	(10,984)	(1,733)	—	(1,733)	(23,220)	—	(23,220)	(5,931)	—	(5,931)
<b>December 31, 2019</b>	100,947	58,348	159,295	27,799	6,894	34,693	176,152	112,932	289,084	50,306	26,302	76,608

CANADA	Shale Gas (Natural Gas) (MMcf)			Conventional Natural Gas (Natural Gas) (MMcf)			Total BOE (Mboe)		
	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +
			Probable			Probable			Probable
<b>December 31, 2018</b>	178,930	105,297	284,228	85,259	39,953	125,212	479,960	266,495	746,455
Discoveries	518	179	698	—	—	—	692	239	931
Extensions and Improved Recovery <sup>(2)</sup>	7,787	6,216	14,003	572	442	1,014	18,134	12,876	31,010
Technical Revisions <sup>(4)</sup>	(8,946)	(12,913)	(21,858)	(2,100)	(4,342)	(6,442)	(25,271)	(34,093)	(59,365)
Acquisitions	1	44	45	1	1	1	2,406	661	3,067
Dispositions <sup>(5)</sup>	(21,651)	(18,399)	(40,050)	(544)	(1,032)	(1,576)	(34,033)	(21,985)	(56,018)
Economic Factors	(453)	(203)	(656)	(3,858)	(1,382)	(5,240)	(5,563)	(740)	(6,302)
Production <sup>(7)</sup>	(17,735)	—	(17,735)	(7,243)	—	(7,243)	(46,031)	—	(46,031)
<b>December 31, 2019</b>	138,452	80,222	218,674	72,086	33,640	105,726	390,294	223,452	613,747

UNITED STATES	Light and Medium Crude Oil (Mbbbls)			Heavy Crude Oil (Mbbbls)			Tight Oil (Mbbbls)			Natural Gas Liquids (Mbbbls)		
	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +
			Probable			Probable			Probable			
<b>December 31, 2018</b>	68	31	99	—	—	—	105,613	78,820	184,433	15,976	10,513	26,489
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery <sup>(3)</sup>	—	—	—	—	—	—	11,517	5,987	17,504	2,090	1,084	3,174
Technical Revisions <sup>(4)</sup>	(11)	(4)	(14)	—	—	—	2,726	(1,465)	1,262	1,668	(611)	1,057
Acquisitions	—	—	—	—	—	—	376	218	595	74	43	117
Dispositions <sup>(6)</sup>	(58)	(27)	(85)	—	—	—	(50,875)	(44,394)	(95,268)	(5,335)	(3,618)	(8,954)
Economic Factors	—	—	—	—	—	—	(336)	(2,047)	(2,383)	(74)	(397)	(471)
Production <sup>(7)</sup>	—	—	—	—	—	—	(10,132)	—	(10,132)	(1,642)	—	(1,642)
<b>December 31, 2019</b>	—	—	—	—	—	—	58,890	37,120	96,010	12,756	7,013	19,769

UNITED STATES	Shale Gas (Natural Gas) (MMcf)			Conventional Natural Gas (Natural Gas) (MMcf)			Total BOE (Mboe)		
	Proved	Probable	Proved +	Proved	Probable	Proved +	Proved	Probable	Proved +
			Probable			Probable			Probable
<b>December 31, 2018</b>	107,585	73,380	180,965	5	2	8	139,589	101,594	241,183
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery <sup>(3)</sup>	6,401	3,338	9,739	—	—	—	14,673	7,628	22,301
Technical Revisions <sup>(5)</sup>	8,260	663	8,923	(4)	(2)	(6)	5,759	(1,969)	3,790
Acquisitions	214	125	339	—	—	—	486	282	769
Dispositions <sup>(6)</sup>	(72,919)	(53,414)	(126,333)	(1)	(1)	(2)	(68,421)	(56,942)	(125,363)
Economic Factors	(215)	(1,150)	(1,365)	—	—	—	(446)	(2,636)	(3,082)
Production <sup>(7)</sup>	(8,453)	—	(8,453)	—	—	—	(13,183)	—	(13,183)
<b>December 31, 2019</b>	40,873	22,942	63,815	—	—	—	78,459	47,956	126,415

TOTAL	Light and Medium Crude Oil (Mbbbls)			Heavy Crude Oil (Mbbbls)			Tight Oil <sup>(4)</sup> (Mbbbls)			Natural Gas Liquids (Mbbbls)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
<b>December 31, 2018</b>	127,424	71,959	199,383	29,015	7,903	36,918	325,347	209,486	534,833	75,800	42,302	118,102
Discoveries	85	29	114	—	—	—	494	171	664	27	9	36
Extensions and Improved Recovery <sup>(2)(3)</sup>	3,658	2,016	5,674	133	10	143	23,186	14,852	38,038	3,371	1,959	5,330
Technical Revisions <sup>(4)</sup>	(648)	(5,637)	(6,285)	670	(951)	(281)	(18,852)	(21,977)	(40,828)	(217)	(4,733)	(4,950)
Acquisitions	2,403	590	2,993	—	—	—	379	266	644	74	60	134
Dispositions <sup>(5) (6)</sup>	(18,884)	(9,986)	(28,871)	—	—	—	(60,061)	(51,101)	(111,162)	(7,656)	(5,699)	(13,355)
Economic Factors	(2,107)	(622)	(2,729)	(285)	(69)	(354)	(2,098)	(1,646)	(3,743)	(765)	(583)	(1,348)
Production <sup>(7)</sup>	(10,984)	—	(10,984)	(1,733)	—	(1,733)	(33,352)	—	(33,352)	(7,573)	—	(7,573)
<b>December 31, 2019</b>	100,947	58,348	159,295	27,799	6,894	34,693	235,043	150,052	385,094	63,062	33,315	96,377

TOTAL	Shale Gas <sup>(5)</sup> (Natural Gas) (MMcf)			Conventional Natural Gas (Natural Gas) (MMcf)			Total BOE (Mboe)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
<b>December 31, 2018</b>	286,515	178,677	465,193	85,264	39,955	125,219	619,549	368,089	987,638
Discoveries	518	179	698	—	—	—	692	239	931
Extensions and Improved Recovery <sup>(2)(3)</sup>	14,188	9,554	23,743	572	442	1,014	32,808	20,503	53,311
Technical Revisions <sup>(4)</sup>	(686)	(12,250)	(12,936)	(2,104)	(4,344)	(6,448)	(19,512)	(36,063)	(55,574)
Acquisitions	216	168	384	1	1	1	2,892	944	3,836
Dispositions <sup>(5) (6)</sup>	(94,570)	(71,813)	(166,383)	(546)	(1,032)	(1,578)	(102,454)	(78,927)	(181,381)
Economic Factors	(668)	(1,354)	(2,021)	(3,858)	(1,382)	(5,240)	(6,009)	(3,376)	(9,385)
Production <sup>(7)</sup>	(26,188)	—	(26,188)	(7,243)	—	(7,243)	(59,214)	—	(59,214)
<b>December 31, 2019</b>	179,325	103,163	282,488	72,086	33,640	105,726	468,753	271,409	740,161

**Notes:**

- (1) Numbers may not add due to rounding.
- (2) The Corporation's Canadian development strategy in 2019 focused on in-fill and development drilling, mostly in the Viewfield Bakken and Flat Lake Torquay resource plays in southeast Saskatchewan as well as the Shaunavon area.
- (3) The Corporation's United States development strategy in 2019 focused on in-fill and development drilling, mostly in the Bakken and Three Forks resource plays in Williams, North Dakota.
- (4) Negative technical revisions on Probable volumes are reflective of reserve volumes being transferred to Proven reserves categories as reserve confidence grows and locations are converted from Probable reserves to Proved plus Probable reserves, through either offset drilling increasing confidence in location bookings, or actual conversion of the location to developed (well) reserves.  
Performance-based negative revisions were observed on existing primary (non-waterflood) Tight Oil assets including the Viewfield Bakken, Flat Lake Torquay and the Shaunavon area resource assets, representing a large portion of the revisions in this category. These revisions were primarily due to a reassessment of the resource basins, which resulted in recognition of performance deviations from early forecasts. The reassessment of the Corporation's producing assets has also resulted in a corresponding negative technical revision on some of the associated area locations, which has in turn been reflected in the Corporation's reserves reported. Additionally, these technical revisions impacted the corresponding Shale Gas and NGL reserves.  
Increased gas-oil ratios from early forecasts in Williams, North Dakota resulted in increases of both Shale Gas and NGL volumes.  
Light and Medium volumes realized negative technical revisions in Proved as well as Proved plus Probable reserves, spread across several plays including Flat Lake Ratcliffe, Provost Viking and Turner Valley Rundle.
- (5) The Corporation's southeast Saskatchewan Light and Medium Crude Oil disposition program represents the majority of values presented. These dispositions closed in the third quarter of 2019.
- (6) The Corporation's disposition of all assets in the Uinta basin of Utah represent most of these volumes, which closed on October 18, 2019.
- (7) The Corporation produced an average of 126,113 boe per day in Canada, 36,117 boe per day in the United States for a total of 162,230 boe per day.

**Undeveloped Reserves**

The following discussion generally describes the basis on which we attribute Proved and Probable undeveloped reserves. Our near-term plans for developing our undeveloped reserves are described in the section "*Major Oil and Gas Properties*".

**Proved Undeveloped Reserves**

Proved Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves represent a high degree of certainty to be recoverable, and mostly relate to planned infill drilling, lease-line and proximal offset locations to current producing entities.

The Corporation has extensive Proved development opportunities that are prioritized based on a disciplined set of criteria including, but not limited to, time for payout, rate of return, maturity of land tenure, reserve booking opportunities, proximity to transportation and marketing, as well as anticipated production rates. With this extensive portfolio of opportunities, it would be unrealistic, both from a cash flow as well as physical ability, to completely execute on the entire portfolio of booked opportunities within two years, however approximately 50% of the development spending occurs within this timeframe.

The development of these reserves have been based on recent and current capital activity levels, with no material deferrals of development opportunities beyond these normal budgetary constraints. The majority of these reserves are planned to be on stream within a three-year timeframe, which represents approximately 81% of the net undeveloped location count, as well as 74% of the net total future development capital. These development activities are directed mostly to the Corporation's core focus areas of Viewfield Bakken, Flat Lake Torquay and Shaunavon resource plays in Canada and the North Dakota Three Forks play in the U.S.

The following table provides the timing of the initial reserve assignments for the Corporation's gross Proved Undeveloped reserves.

*Timing of Initial Proved Undeveloped Reserve Assignment*

	Light & Medium Crude Oil (Mbbbl)		Heavy Crude Oil (Mbbbl)		Tight Oil (Mbbbl)		Natural Gas Liquids (Mbbbl)		Shale Gas (MMcf)		Conventional Natural Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End
2017	1,745	37,676	—	1,991	24,359	140,487	3,968	24,311	18,569	128,064	118	18,679	33,187	228,922
2018	7,706	33,819	—	1,771	27,622	138,096	3,963	25,357	17,358	119,169	2,390	12,882	42,582	221,051
2019	3,829	28,122	—	1,645	16,482	95,922	2,144	19,659	10,262	66,614	169	10,750	24,194	158,242

**Note:**

(1) "First attributed" refers to reserves first attributed at year-end to corresponding fiscal year.

**Probable Undeveloped Reserves**

Probable Undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, and lands contiguous to production. These reserves represent quantities that are less certain to be recovered than Proved reserves.

In the reserve evaluation, development of these reserves is balanced across a five-year time-frame to closely match the aggregate internal development schedule and represent a practicable development program. The majority of these reserves are planned to be on stream within a three-year timeframe, representing approximately 69% of the net undeveloped location count, as well as 64% of the total net future development costs. Other than for normal budgetary constraints, the Corporation has no plans to defer development of Probable Undeveloped reserves. This broader distribution of development activities continues to focus on the Corporation's core areas, while reclassifying current Probable locations to Proved locations during the early years of development. These development activities are directed mostly to the Corporation's core focus areas of Viewfield Bakken, Flat Lake Torquay and Shaunavon resource plays in Canada and the North Dakota Three Forks and Bakken plays in the U.S. The Corporation's Swan Hills area development program is scheduled over ten years to match current development plans.

The following table provides the timing of the initial reserve assignments for the Corporation's Probable Undeveloped reserves.

*Timing of Initial Probable Undeveloped Reserves Assignment*

	Light & Medium Crude Oil (Mbbbl)		Heavy Crude Oil (Mbbbl)		Tight Oil (Mbbbl)		Natural Gas Liquids (Mbbbl)		Shale Gas (MMcf)		Conventional Natural Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End	First Attributed <sup>(1)</sup>	Total at Year-End
2017	2,184	52,846	—	1,444	30,640	129,585	4,774	22,570	19,996	105,133	614	28,756	41,033	228,760
2018	5,594	43,709	—	1,403	28,892	133,715	4,220	24,636	24,749	105,633	1,918	21,538	43,151	224,658
2019	1,990	33,955	—	1,161	12,405	91,941	1,522	19,066	8,090	58,496	319	18,126	17,318	158,893

**Note:**

(1) "First attributed" refers to reserves first attributed at year end of the corresponding fiscal year.

**Significant Factors or Uncertainties Affecting Reserves Data**

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. Our reserves are evaluated by GLJ and Sproule, each an independent engineering firm. Different reserve engineers may make different estimates of reserve quantities based on the same data.

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, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions and judgments, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from numerous factors including, but not limited to, additional development activity, evolving production history, continual reassessment of the viability of production under varying economic conditions, changes in forecast prices, and reservoir performance. Such revisions can be substantial and can be either positive or negative.

## Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to total Proved reserves and total Proved plus Probable reserves (using forecast prices and costs).

Company Annual Capital Expenditures (MM\$)						
Year	Canada <sup>(2)</sup>		United States <sup>(3)</sup>		Total <sup>(1)</sup>	
	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable
2020	614	698	184	237	798	935
2021	621	841	287	339	907	1,180
2022	613	871	217	268	831	1,139
2023	398	781	157	185	555	966
2024	116	366	203	203	319	569
2025	5	70	—	—	5	70
2026	3	49	—	—	3	49
2027	2	60	—	—	2	60
2028	7	47	—	—	7	47
2029	3	59	—	—	3	59
2030	1	2	—	—	1	2
2031	1	2	—	—	1	2
Subtotal <sup>(1)</sup>	2,383	3,845	1,048	1,232	3,431	5,077
Remainder	10	17	—	—	10	17
Total <sup>(1)</sup>	2,393	3,862	1,048	1,232	3,441	5,094
10% Discounted	1,986	3,031	839	995	2,825	4,025

### Notes:

- (1) Numbers may not add due to rounding.
- (2) In Canada, the Corporation drilled 450 (420.1 net) wells in 2019. For 2020, the Corporation has budgeted the drilling of 457 (426.0 net) wells. Due to the nature of the resource style plays that Crescent Point is focused on, with large contiguous blocks of land, a large number of Proved as well as Proved plus Probable locations have been booked. The scheduling of locations by the qualified reserve evaluators have a similar drilling timing as the Corporation's long-term development plan. As a result, the total Proved and almost all of the total Proved plus Probable drilling schedule occur within a five year period. The remaining capital expenditures beyond the five year period essentially relate to maintenance capital on existing wells and assets. The development program in Swan Hills, which represents less than five percent of the Corporation's total net Proved plus Probable location count, is scheduled over ten years. The timing of this maintenance capital may vary between Proved and Proved plus Probable reserve categories, due to such factors as longer forecast lives on Proved plus Probable versus Proved reserves.
- (3) In the United States, Crescent Point drilled 60 (45.7 net) wells in 2019, while in 2020, the Corporation is budgeting the drilling of 24 (20.1 net) wells. As in Canada, a large number of Proved as well as Proved plus Probable locations have been booked. The scheduling of locations by the qualified reserve evaluators have a similar drilling timing as the Corporation's long-term development plan. As a result, both the total Proved and total Proved plus Probable drilling schedule occur within a five year period.

We estimate that our internally generated cash flow will be sufficient to fund the future development costs ("FDC") disclosed above. In addition, we have access to debt financing through our bank credit facilities and through debt capital markets, if available on terms acceptable to us.

## Major Oil and Gas Properties

The following is a description of the major oil and natural gas producing regions, properties, plants, facilities and installations in which Crescent Point has an interest and that are material to the Corporation's operations and activities. All of the Corporation's assets are located onshore. The Corporation holds no interests in any plants, facilities or installations that are significant beyond normal oil and gas operating practices, in major properties described below, or in less material producing areas. Unless otherwise noted, reserve amounts are Company Gross, based on escalating cost and price assumptions as evaluated in the Crescent Point Reserve Report as at December 31, 2019.

The Corporation has disposed of gas infrastructure assets in Saskatchewan for total cash consideration of \$500 million, as of January 20, 2020. Disposed assets include nine natural gas gathering and processing facilities and two gas sales pipelines. The disposition of these assets was not reflected in the Crescent Point Reserve Report as of December 31, 2019. The impact of the disposition will be an increase in observed operating costs in those specific areas through the assignment of third-party processing fees charged against volumes produced. This impact has been estimated pro-forma as \$314.5 million at a discounted rate of 10% on total Proved plus Probable reserves.

### ***Viewfield Bakken Resource***

Crescent Point is the largest Canadian producer across the Viewfield Bakken resource area in southeastern Saskatchewan, with 2019 average production of approximately 41,900 boe per day. Production is a high quality light oil and is exploited using multi-fractured horizontal wells. The core area of the resource base is almost all at 100% working interest rights, most of which has now been unitized. The Corporation is now in the process of planning and proposing additional units in the Bakken resource play to initiate additional waterflood projects. The Bakken play in this area has continued to be a major driver in the Corporation's portfolio, maturing from early development and delineation drilling activities to the current focus on reservoir development through infill drilling, pool extensions and waterflood advancements.

Crescent Point spent \$244 million, representing approximately 19% of its 2019 capital development program, on the Viewfield Bakken resource area including drilling 127 (120.9 net) additional oil wells. The Corporation also continued to focus on waterflood development expansion.

At year end 2019, the Corporation's total Proved plus Probable reserves in the Viewfield Bakken area were 208.6 MMboe, with 610 (568.0 net) locations booked to these reserves. This represents approximately 28% of the Corporation's total Proved plus Probable reserves. Both the Total Proved as well as the Total Proved plus Probable locations are expected to be developed within five years based on recent and current planned development rates in the area. Of the Total Proved locations, 83% are to be drilled within the first three years.

In 2020, Crescent Point has allocated 21% of the Corporation's capital budget to development of the Viewfield Bakken resource play, primarily focused on in-fill drilling, as well as additional waterflood development.

### ***Shaunavon Area***

The Shaunavon resource area, located in southwest Saskatchewan, has development occurring in the Upper and Lower Shaunavon resource zones, as well as conventional Upper Shaunavon pools, all of which are medium quality oil. The Upper Shaunavon resource and conventional zones, as well as the Lower Shaunavon resource zone exist both individually and together as stratified pools. The conventional portions of the Upper Shaunavon have been under development for several decades, having originally been developed using vertical wells, and, more recently, using horizontal wells. Both waterfloods and enhanced recovery techniques are being used to increase recovery factors in these pools. The tight oil Upper and Lower resource plays have been developed using fracture stimulated horizontal wells and, more recently, by advancing waterflood techniques that have continued to grow production in the area. In 2019, Crescent Point's production averaged approximately 26,400 boe per day in the area.

In 2019, the Corporation continued to develop the Shaunavon area by drilling 118 (115.7 net) wells, and waterflood optimization to enhance recoveries. Total capital spent on these activities in 2019 was \$225 million, representing approximately 18% of the Corporation's capital budget.

As of year end 2019, Crescent Point has booked total Proved plus Probable reserves of 130.4 MMboe in the Shaunavon area, representing approximately 18% of the total Proved plus Probable reserves. The Corporation has 652 (635.8 net) locations booked to total Proved plus Probable reserves as of year end 2019. Crescent Point expects to fully develop this location inventory within five years, with 84% of the Total Proved locations being developed in three years.

In 2020, Crescent Point has allocated 23% of the Corporation's capital budget to development of the Shaunavon area. The Corporation plans to continue to advance waterflood optimization in the Lower and Upper Shaunavon zones, as well as advance enhanced oil recovery projects in conventional areas within the area.

### ***Flat Lake Area***

The Flat Lake area is situated directly north of the U.S. border in southeastern Saskatchewan, where the Corporation is developing the Bakken and Torquay resource plays, as well as the conventional Ratcliffe (Oungre) play, all with horizontal wells. Production in the area averaged approximately 19,800 boe per day in 2019. The Corporation's focus in the Ratcliffe play has been development drilling, followed by implementation of coordinated waterfloods to improve recoveries.

The Corporation spent \$252 million, representing 20% of its 2019 capital program, mostly on the Torquay and Ratcliffe plays in Flat Lake including drilling 92 (88.9 net) wells. The Corporation also continued to focus on waterflood development and facility enhancements during the year.



At year end 2019, the Corporation's total Proved plus Probable reserves in the Flat Lake area were 63.8 MMboe, representing approximately 9% of the Corporation's total reserves in this category, a reduction from year end 2018 primarily due to asset dispositions that closed during the year. Included in these reserve volume bookings were 297 (290.3 net) locations. It is expected all the Total Proved locations will be developed within four years, while all Total Proved plus Probable locations will be developed in five years.

In 2020, Crescent Point has allocated 15% of the Corporation's capital budget to the development of the Torquay and Ratcliffe plays. Where possible, the Corporation has started developing the Torquay assets using two mile horizontal wells. As this drilling occurs, prior one mile location bookings are converted to the actual drilled two mile wells. This program is designed to expand and diversify our asset base, expand the potential for waterflood implementation and further develop our drilling inventory.

### **North Dakota**

The Corporation is developing both the Three Forks and Bakken resource plays in North Dakota. Production is a high quality light oil and is developed using multi-fractured horizontal wells, with 2019 average working interest production rates of approximately 19,900 boe per day.

In North Dakota, the Corporation spent \$253 million representing 20% of its 2019 capital program, drilling 37 (34.0 net) horizontal wells focusing on pad drilling these assets.

At year end 2019, the Corporation's Total Proved plus Probable reserves in North Dakota were 126.4 MMboe, with 200 (154.7 net) locations booked, representing approximately 17% of the Corporation's total Proved plus Probable reserves. It is expected the Total Proved as well as the Total Proved plus Probable locations will all be developed within five years, with 70% of Total Proved locations being developed within three years.

In 2020, Crescent Point has allocated 22% of the Corporation's capital budget to developing the Three Forks and Bakken resource plays in North Dakota.

### **Oil and Gas Wells**

Producing Wells					
Area	Oil		Gas		
	Gross	Net	Gross	Net	
<b>CANADA</b>					
Saskatchewan	8,722	7,347	371	125	
Alberta	491	406	322	216	
Manitoba	1	—	—	—	
British Columbia	9	6	—	—	
<b>TOTAL CANADA</b>	<b>9,223</b>	<b>7,759</b>	<b>693</b>	<b>341</b>	
<b>U.S.</b>					
North Dakota	171	127	—	—	
Montana	1	—	—	—	
<b>TOTAL U.S.</b>	<b>172</b>	<b>127</b>	<b>—</b>	<b>—</b>	
<b>Total</b>	<b>9,395</b>	<b>7,886</b>	<b>693</b>	<b>341</b>	

Non-Producing Wells				
Area	Oil		Gas	
	Gross	Net	Gross	Net
<b>CANADA</b>				
Saskatchewan	4,305	3,521	489	352
Alberta	393	273	194	152
Manitoba	—	—	—	—
British Columbia	—	—	1	1
<b>TOTAL CANADA</b>	<b>4,698</b>	<b>3,794</b>	<b>684</b>	<b>505</b>
<b>U.S.</b>				
North Dakota	1	1	—	—
Montana	—	—	—	—
<b>TOTAL U.S.</b>	<b>1</b>	<b>1</b>	<b>—</b>	<b>—</b>
<b>Total</b>	<b>4,699</b>	<b>3,795</b>	<b>684</b>	<b>505</b>

**Note:**

(1) Gross and net producing and non-producing oil and gas counts include both reserve assigned and non-reserve assigned wells.

All of the Corporation's oil and gas wells are onshore. Non-producing wells are generally situated within defined developed areas and include recent drills awaiting final preparation prior to being placed on production; existing wells that may be waiting on improved economic conditions to restart; wells currently in use for observation or monitoring; wells awaiting recompletion in secondary zones or as injectors; or wells scheduled for abandonment. These non-producing entities include wells with reserve assignments as well as currently non-booked wells, which will have various terms of being non-producing from recent to longer-term.

Non-producing reserves represent only 1.2% of the Total Proved reserve category, and 1.3% of the Total Proved plus Probable reserve category. Wells in the non-producing category exist across most of the Corporation's areas and mostly represent wells awaiting final preparation for production, and wells with secondary producing zones that continue to produce out of the primary zone.

**Properties With No Attributed Reserves**

The following table summarizes the gross and net acres of unproved properties in which we have an interest and also the number of net acres for which our rights to develop or exploit will, absent further action, expire within one year.

As of December 31, 2019			
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
<b>CANADA</b>			
Alberta	544,867	486,226	109,846
Saskatchewan	760,546	682,465	88,020
Manitoba	—	—	—
British Columbia	30,610	18,429	—
<b>Total</b>	<b>1,336,023</b>	<b>1,187,120</b>	<b>197,866</b>
<b>U.S.</b>			
Montana	—	—	—
North Dakota	24,897	21,057	990
<b>Total</b>	<b>24,897</b>	<b>21,057</b>	<b>990</b>
<b>Total</b>	<b>1,360,920</b>	<b>1,208,177</b>	<b>198,856</b>

The Corporation has no drilling commitments relating to unproved properties.

## Drilling Activity

The following table summarizes the gross and net exploration and development wells in which we participated during the year ended December 31, 2019, in each of Canada and the United States.

	Development Wells		Exploration Wells <sup>(2)</sup>		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil wells	444	415	3	3	447	418
Natural Gas wells	—	—	—	—	—	—
Service wells	3	3	—	—	3	3
Stratigraphic test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
<b>Total<sup>(1)</sup></b>	<b>447</b>	<b>418</b>	<b>3</b>	<b>3</b>	<b>450</b>	<b>421</b>

	Development Wells		Exploration Wells <sup>(2)(3)</sup>		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Oil wells	53	39	6	6	59	45
Natural Gas wells	—	—	—	—	—	—
Service wells	1	1	—	—	1	1
Stratigraphic Test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
<b>Total<sup>(1)</sup></b>	<b>54</b>	<b>40</b>	<b>6</b>	<b>6</b>	<b>60</b>	<b>46</b>

**Notes:**

- (1) Numbers may not add due to rounding.
- (2) Exploration wells in this grouping are based on the well licence classification at the time of drilling.
- (3) Exploration wells in the U.S. were part of the Utah disposition, therefore, are not included in reserve volumes for 2019.

For details on important exploration and development activities during 2019, see "Statement of Reserves Data and Other Oil and Gas Information – Major Oil and Gas Properties".

The Corporation has no work commitments for its proved properties (including drilling commitments) in Canada or the U.S. for the next three years.

## Tax Horizon

Crescent Point had tax pools of approximately \$10.7 billion at December 31, 2019 to shelter future taxable income. Based on this pool balance and forecast cash flows using forward benchmark prices in effect on the date of this AIF, with the Corporation's development capital plans, Crescent Point does not expect to be taxable in the next five years.

## Costs Incurred<sup>(1)</sup>

The following table summarizes our property acquisition costs, exploration costs and development costs for the year ended December 31, 2019. The total capital costs were approximately \$1.3 billion in 2019.

(\$ millions)	Acquisition Costs <sup>(2)</sup>			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Canada	0.6	—	16.1	883.4
U.S.	8.5	7.3	19.1	349.0
<b>Total</b>	<b>9.1</b>	<b>7.3</b>	<b>35.2</b>	<b>1,232.4</b>

**Notes:**

- (1) Costs incurred exclude capitalized administration.
- (2) Excludes disposition proceeds of \$838.5 million and \$101.9 million for proved and unproved properties, respectively.

## Production Estimates

The following table discloses for each product type the gross volume of production estimated by GLJ and Sproule for 2020 in the estimates of future net revenue with forecast pricing from Proved reserves disclosed above under the heading "Reserves Data – Forecast Prices and Costs".

	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas	Total
	(bbls/d)	(bbls/d)	(bbls/d)	(bbls/d)	(Mcf/d)	(Mcf/d)	(boe/d)
CANADA							
Alberta and British Columbia	6,156	—	686	2,482	1,039	10,200	11,198
Southwest Saskatchewan <sup>(2)</sup>	10,740	4,812	21,251	467	14,991	1,643	40,042
Southeast Saskatchewan	14,395	—	34,821	11,941	28,869	4,408	66,703
<b>Total CANADA<sup>(1)</sup></b>	<b>31,291</b>	<b>4,812</b>	<b>56,758</b>	<b>14,890</b>	<b>44,900</b>	<b>16,252</b>	<b>117,943</b>
U.S.							
North Dakota and Montana	—	—	12,726	3,213	9,967	—	17,601
<b>Total U.S.<sup>(1)</sup></b>	<b>—</b>	<b>—</b>	<b>12,726</b>	<b>3,213</b>	<b>9,967</b>	<b>—</b>	<b>17,601</b>
<b>Total Corporate<sup>(1)</sup></b>	<b>31,291</b>	<b>4,812</b>	<b>69,484</b>	<b>18,104</b>	<b>54,867</b>	<b>16,252</b>	<b>135,544</b>

**Notes:**

(1) Numbers may not add due to rounding.

(2) Assets in Southwest Saskatchewan include all southwest Saskatchewan, as well as Viking assets in western Saskatchewan.

In 2020, production at Viewfield in southeast Saskatchewan is estimated at 45,200 boe per day, representing 33%, and production in the Shaunavon area of southwest Saskatchewan is estimated at 28,000 boe per day, representing 21%, of the Corporation's Proved production estimate in the Crescent Point Reserve Report, respectively. Remaining areas each account for a small portion of the Corporation's production estimates for 2020.

The following table discloses, for each product type, the gross volume of production estimated by GLJ and Sproule for 2020 in the estimates of future net revenue with forecast pricing from Proved plus Probable reserves disclosed above under the heading "Reserves Data – Forecast Prices and Costs".

Region	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas	Total
	(bbls/d)	(bbls/d)	(bbls/d)	(bbls/d)	(Mcf/d)	(Mcf/d)	(boe/d)
CANADA							
Alberta and British Columbia	6,639	—	760	2,604	1,140	10,617	11,963
Southwest Saskatchewan <sup>(2)</sup>	12,189	5,037	25,181	538	17,385	1,805	46,143
Southeast Saskatchewan	15,644	—	39,618	13,411	32,527	4,812	74,896
<b>Total CANADA<sup>(1)</sup></b>	<b>34,472</b>	<b>5,037</b>	<b>65,559</b>	<b>16,553</b>	<b>51,052</b>	<b>17,235</b>	<b>133,002</b>
U.S.							
North Dakota and Montana	—	—	15,565	3,739	11,640	—	21,244
<b>Total U.S.<sup>(1)</sup></b>	<b>—</b>	<b>—</b>	<b>15,565</b>	<b>3,739</b>	<b>11,640</b>	<b>—</b>	<b>21,244</b>
<b>Total Corporate<sup>(1)</sup></b>	<b>34,472</b>	<b>5,037</b>	<b>81,123</b>	<b>20,292</b>	<b>62,691</b>	<b>17,235</b>	<b>154,246</b>

**Notes:**

(1) Numbers may not add due to rounding.

(2) Assets in Southwest Saskatchewan include all southwest Saskatchewan, as well as Viking assets in western Saskatchewan.

In 2020, production at Viewfield in southeast Saskatchewan is estimated at 50,000 boe per day, accounting for 32%, and production in the Shaunavon area of southwest Saskatchewan is estimated at 32,800 boe per day, representing 21%, of the Corporation's total Proved plus Probable production estimate, respectively. Remaining areas each account for a small portion of the Corporation's production estimates for 2020.

## Production History

The following tables disclose, on a quarterly and annual basis for the year ended December 31, 2019, our share of average daily production volume (prior to deducting royalties), and the prices received, royalties, production costs and transportation costs incurred and netbacks on a per unit of volume basis for each product type.

### Average Daily Production Volume<sup>(1)</sup>

	Three Months Ended				Year Ended
	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
<b>CANADA</b>					
Light and Medium Crude Oil (bbls/d)	33,423	32,420	29,265	25,366	30,094
Heavy Crude Oil (bbls/d)	4,824	4,633	4,722	4,819	4,749
Tight Oil (bbls/d)	65,289	67,312	60,052	61,891	63,617
NGLs (bbls/d)	15,514	16,517	16,258	16,686	16,248
Shale Gas (Mcf/d)	48,831	53,348	50,421	41,814	48,589
Conventional Natural Gas (Mcf/d)	21,254	20,817	19,443	17,901	19,843
<b>Total (boe/d)</b>	<b>130,731</b>	<b>133,243</b>	<b>121,941</b>	<b>118,715</b>	<b>126,113</b>
<b>U.S.</b>					
Light and Medium Crude Oil (bbls/d)	—	—	—	—	—
Heavy Crude Oil (bbls/d)	—	—	—	—	—
Tight Oil (bbls/d)	36,375	30,586	24,972	19,318	27,759
NGLs (bbls/d)	4,583	4,324	4,369	4,720	4,498
Shale Gas (Mcf/d)	25,594	25,936	26,558	14,632	23,160
Conventional Natural Gas (Mcf/d)	—	—	—	—	—
<b>Total (boe/d)</b>	<b>45,224</b>	<b>39,233</b>	<b>33,767</b>	<b>26,477</b>	<b>36,117</b>
<b>TOTAL</b>					
Light and Medium Crude Oil (bbls/d)	33,423	32,420	29,265	25,366	30,094
Heavy Crude Oil (bbls/d)	4,824	4,633	4,722	4,819	4,749
Tight Oil (bbls/d)	101,664	97,898	85,024	81,209	91,376
NGLs (bbls/d)	20,097	20,841	20,627	21,406	20,746
Shale Gas (Mcf/d)	74,425	79,284	76,979	56,446	71,749
Conventional Natural Gas (Mcf/d)	21,254	20,817	19,443	17,901	19,843
<b>Total (boe/d)</b>	<b>175,955</b>	<b>172,476</b>	<b>155,708</b>	<b>145,192</b>	<b>162,230</b>

**Note:**

(1) Numbers may not add due to rounding.

*Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Light and Medium Crude Oil*

(\$ per bbl)	Three Months Ended				Year Ended
	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
<b>CANADA</b>					
Prices Received – net of hedging	63.10	71.13	67.56	68.29	67.46
Royalties	(7.74)	(10.84)	(10.38)	(9.84)	(9.66)
Production Costs(1)	(14.04)	(14.96)	(14.98)	(14.20)	(14.55)
Transportation Costs(1)	(2.44)	(2.54)	(2.51)	(2.69)	(2.54)
<b>Netback</b>	<b>38.88</b>	<b>42.79</b>	<b>39.69</b>	<b>41.56</b>	<b>40.71</b>
<b>U.S.</b>					
Prices Received – net of hedging	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs(1)	—	—	—	—	—
Transportation Costs(1)	—	—	—	—	—
<b>Netback</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>TOTAL</b>					
Prices Received – net of hedging	63.10	71.13	67.56	68.29	67.46
Royalties	(7.74)	(10.84)	(10.38)	(9.84)	(9.66)
Production Costs(1)	(14.04)	(14.96)	(14.98)	(14.20)	(14.55)
Transportation Costs(1)	(2.44)	(2.54)	(2.51)	(2.69)	(2.54)
<b>Netback</b>	<b>38.88</b>	<b>42.79</b>	<b>39.69</b>	<b>41.56</b>	<b>40.71</b>

**Note:**

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

*Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Heavy Crude Oil*

(\$ per bbl)	Three Months Ended				Year Ended
	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
<b>CANADA</b>					
Prices Received	59.41	66.54	60.90	57.19	60.95
Royalties	(12.07)	(17.89)	(15.47)	(14.61)	(14.98)
Production Costs <sup>(1)</sup>	(13.42)	(13.73)	(13.90)	(12.39)	(13.35)
Transportation Costs <sup>(1)</sup>	(2.00)	(1.94)	(1.75)	(1.90)	(1.90)
<b>Netback</b>	<b>31.92</b>	<b>32.98</b>	<b>29.78</b>	<b>28.29</b>	<b>30.72</b>
<b>U.S.</b>					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs <sup>(1)</sup>	—	—	—	—	—
Transportation Costs <sup>(1)</sup>	—	—	—	—	—
<b>Netback</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>TOTAL</b>					
Prices Received	59.41	66.54	60.90	57.19	60.95
Royalties	(12.07)	(17.89)	(15.47)	(14.61)	(14.98)
Production Costs <sup>(1)</sup>	(13.42)	(13.73)	(13.90)	(12.39)	(13.35)
Transportation Costs <sup>(1)</sup>	(2.00)	(1.94)	(1.75)	(1.90)	(1.90)
<b>Netback</b>	<b>31.92</b>	<b>32.98</b>	<b>29.78</b>	<b>28.29</b>	<b>30.72</b>

**Note:**

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

*Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Tight Oil*

(\$ per bbl)	Three Months Ended				Year Ended
	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
<b>CANADA</b>					
Prices Received – net of hedging	68.14	71.69	69.40	68.59	69.48
Royalties	(6.74)	(7.62)	(6.70)	(6.63)	(6.94)
Production Costs <sup>(1)</sup>	(15.16)	(15.08)	(15.39)	(14.26)	(14.97)
Transportation Costs <sup>(1)</sup>	(3.45)	(3.09)	(2.87)	(3.06)	(3.12)
Netback	42.79	45.90	44.44	44.64	44.45
<b>U.S.</b>					
Prices Received – net of hedging	63.27	70.23	65.07	65.17	65.92
Royalties	(13.83)	(18.18)	(18.03)	(19.01)	(16.88)
Production Costs <sup>(1)</sup>	(14.01)	(13.59)	(15.27)	(9.79)	(13.44)
Transportation Costs <sup>(1)</sup>	(0.24)	(0.20)	(1.21)	(0.64)	(0.52)
Netback	35.19	38.26	30.56	35.73	35.08
<b>TOTAL</b>					
Prices Received – net of hedging	66.39	71.23	68.13	67.78	68.40
Royalties	(9.28)	(10.92)	(10.03)	(9.58)	(9.96)
Production Costs <sup>(1)</sup>	(14.75)	(14.61)	(15.35)	(13.20)	(14.51)
Transportation Costs <sup>(1)</sup>	(2.30)	(2.19)	(2.39)	(2.48)	(2.33)
Netback	40.06	43.51	40.36	42.52	41.60

**Note:**

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

*Prices Received, Royalties, Production Costs and Transportation Costs Incurred – NGLs*

(\$ per bbl)	Three Months Ended				Year Ended
	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
<b>CANADA</b>					
Prices Received	25.10	21.16	13.53	19.36	19.69
Royalties	(1.68)	(1.28)	(0.92)	(1.13)	(1.24)
Production Costs <sup>(1)</sup>	(6.33)	(4.93)	(3.22)	(4.43)	(4.70)
Transportation Costs <sup>(1)</sup>	(0.71)	(0.52)	(0.92)	(0.72)	(0.72)
Netback	16.38	14.43	8.47	13.08	13.03
<b>U.S.</b>					
Prices Received	27.22	22.25	16.19	17.81	20.85
Royalties	(5.64)	(4.67)	(4.02)	(4.18)	(4.63)
Production Costs <sup>(1)</sup>	(5.48)	(3.94)	(3.63)	(2.56)	(3.89)
Transportation Costs <sup>(1)</sup>	(0.21)	(0.35)	(0.19)	(0.08)	(0.20)
Netback	15.89	13.29	8.35	10.99	12.13
<b>TOTAL</b>					
Prices Received	25.58	21.39	14.09	19.02	19.94
Royalties	(2.58)	(1.98)	(1.57)	(1.80)	(1.98)
Production Costs <sup>(1)</sup>	(6.13)	(4.72)	(3.31)	(4.02)	(4.52)
Transportation Costs <sup>(1)</sup>	(0.60)	(0.48)	(0.77)	(0.58)	(0.61)
Netback	16.27	14.21	8.44	12.62	12.83

**Note:**

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Shale Gas

(\$ per Mcf)	Three Months Ended				Year Ended
	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
<b>CANADA</b>					
Prices Received - net of hedging	4.04	2.17	2.26	3.88	3.03
Royalties	(0.31)	(0.16)	(0.10)	(0.26)	(0.20)
Production Costs <sup>(1)</sup>	(0.96)	(1.07)	(0.52)	(0.90)	(0.86)
Transportation Costs <sup>(1)</sup>	(0.20)	(0.19)	(0.19)	(0.31)	(0.22)
Netback	2.57	0.75	1.45	2.41	1.75
<b>U.S.</b>					
Prices Received - net of hedging	4.50	3.20	2.56	2.75	3.30
Royalties	(0.34)	(0.12)	(0.63)	0.72	(0.20)
Production Costs <sup>(1)</sup>	(1.03)	(0.63)	(0.62)	(0.46)	(0.71)
Transportation Costs <sup>(1)</sup>	(0.68)	(0.83)	(0.30)	(0.03)	(0.51)
Netback	2.45	1.62	1.01	2.98	1.88
<b>TOTAL</b>					
Prices Received - net of hedging	4.20	2.51	2.36	3.59	3.11
Royalties	(0.33)	(0.15)	(0.28)	—	(0.20)
Production Costs <sup>(1)</sup>	(0.98)	(0.92)	(0.55)	(0.78)	(0.81)
Transportation Costs <sup>(1)</sup>	(0.36)	(0.40)	(0.23)	(0.24)	(0.31)
Netback	2.53	1.04	1.30	2.57	1.79

**Note:**

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Conventional Natural Gas

(\$ per Mcf)	Three Months Ended				Year Ended
	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
<b>CANADA</b>					
Prices Received - net of hedging	3.44	2.08	1.91	3.00	2.61
Royalties <sup>(2)</sup>	0.53	0.43	(0.35)	0.29	0.23
Production Costs <sup>(1)</sup>	(0.81)	(1.02)	(0.44)	(0.69)	(0.75)
Transportation Costs <sup>(1)</sup>	(0.30)	(0.30)	(0.33)	(0.18)	(0.28)
Netback	2.86	1.19	0.79	2.42	1.81
<b>U.S.</b>					
Prices Received - net of hedging	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs <sup>(1)</sup>	—	—	—	—	—
Transportation Costs <sup>(1)</sup>	—	—	—	—	—
Netback	—	—	—	—	—
<b>TOTAL</b>					
Prices Received - net of hedging	3.44	2.08	1.91	3.00	2.61
Royalties <sup>(2)</sup>	0.53	0.43	(0.35)	0.29	0.23
Production Costs <sup>(1)</sup>	(0.81)	(1.02)	(0.44)	(0.69)	(0.75)
Transportation Costs <sup>(1)</sup>	(0.30)	(0.30)	(0.33)	(0.18)	(0.28)
Netback	2.86	1.19	0.79	2.42	1.81

**Notes:**

(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on a number of assumptions.

(2) In Canada, royalties include the impact of the gas cost allowance.



## Production Volume by Field

The following table discloses for each important field, and in total, our production volumes for the year ended December 31, 2019 for each product type.

Region	Light and Medium Crude Oil (bbls/d)	Heavy Crude Oil (bbls/d)	Tight Oil (bbls/d)	NGLs (bbls/d)	Shale Gas (Mcf/d)	Conventional Natural Gas (Mcf/d)	Total (boe/d)
<b>CANADA</b>							
Viewfield	4,600	—	10,231	2,967	8,792	3,284	19,811
Flat Lake	4,825	—	27,474	10,381	23,230	1,581	46,815
Shaunavon	3,202	—	20,070	458	15,399	544	26,387
Other Canada <sup>(2)</sup>	17,467	4,749	5,842	2,442	1,168	14,434	33,100
<b>Total CANADA<sup>(1)</sup></b>	<b>30,094</b>	<b>4,749</b>	<b>63,617</b>	<b>16,248</b>	<b>48,589</b>	<b>19,843</b>	<b>126,113</b>
<b>U.S.</b>							
North Dakota	—	—	14,531	3,635	10,187	—	19,864
Utah <sup>(3)</sup>	—	—	13,224	863	12,918	—	16,240
Other U.S.	—	—	4	—	55	—	13
<b>Total U.S.<sup>(1)</sup></b>	<b>—</b>	<b>—</b>	<b>27,759</b>	<b>4,498</b>	<b>23,160</b>	<b>—</b>	<b>36,117</b>
<b>Total<sup>(1)</sup></b>	<b>30,094</b>	<b>4,749</b>	<b>91,376</b>	<b>20,746</b>	<b>71,749</b>	<b>19,843</b>	<b>162,230</b>

**Notes:**

- (1) Numbers may not add due to rounding.
- (2) Includes all remaining assets in Canada.
- (3) Utah assets were disposed of on October 18, 2019.

## ADDITIONAL INFORMATION RESPECTING CRESCENT POINT

### Directors and Officers

Crescent Point has a board of directors currently consisting of nine individuals. The directors are elected by the Corporation, at the direction of Shareholders by ordinary resolution, and hold office until the next annual meeting of the Corporation.

The name, municipality of residence and principal occupation during the last five years of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held with the Corporation	Date First Elected or Appointed as Director
Craig Bryksa <sup>(4)</sup> Calgary, Alberta	President, Chief Executive Officer and Director	2018
Kenneth R. Lamont Calgary, Alberta	Chief Financial Officer	Not applicable
Ryan Gritzfeldt Calgary, Alberta	Chief Operating Officer	Not applicable
Brad Borggard Calgary, Alberta	Senior Vice President, Corporate Planning and Capital Markets	Not applicable
Mark G. Eade Calgary, Alberta	Senior Vice President, General Counsel and Corporate Secretary	Not applicable
Garret Holt Calgary, Alberta	Senior Vice President, Corporate Development	Not applicable
Barbara Munroe <sup>(6)</sup> Calgary, Alberta	Director and Chair of the Board	2016
Laura A. Cillis <sup>(1)(2)</sup> Calgary, Alberta	Director	2014
James E. Craddock <sup>(1)(3)(5)</sup> Calgary, Alberta	Director	2019
John P. Dielwart <sup>(3)(4)</sup> Calgary, Alberta	Director	2019
Ted Goldthorpe <sup>(1)(5)</sup> New York, New York	Director	2017
Mike Jackson <sup>(1)(2)(5)</sup> Calgary, Alberta	Director	2016
Jennifer F. Koury <sup>(2)(4)</sup> Calgary, Alberta	Director	2019
Francois Langlois <sup>(3)(4)(5)</sup> Calgary, Alberta	Director	2018

**Notes:**

- (1) Member of the Audit Committee.
- (2) Member of the Human Resources and Compensation Committee.
- (3) Member of the Reserves Committee.
- (4) Member of the Environmental, Health and Safety Committee.
- (5) Member of Corporate Governance and Nominating Committee.
- (6) Chair of the Board shall serve in an ex officio capacity on each Committee.

As at February 13, 2020, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 801,703 Common Shares, representing approximately 0.2% of the issued and outstanding Common Shares. Including restricted shares and options, ownership increased to 0.5% on a fully diluted basis.

*Craig Bryksa, President, Chief Executive Officer and Director*

Craig Bryksa is the President, Chief Executive Officer and a Director of Crescent Point, roles he has held since September 2018. Prior to his current position, Mr. Bryksa was Vice President, Engineering West and has held a number of senior management roles with Crescent Point since joining the company in 2006, directly overseeing the development and operations of each of Crescent Point's core assets.

Mr. Bryksa has spent 18 years as a professional engineer in the oil and gas industry, working with companies such as Enerplus Resources Fund and McDaniel & Associates Consultants. Mr. Bryksa is a member of the Association of Professional Engineers and Geoscientists of Alberta ("APEGA") and Association of Professional Engineers and Geoscientists of Saskatchewan ("APEGS"). He holds a Bachelor of Applied Science degree in petroleum engineering from the University of Regina.

*Ken Lamont, Chief Financial Officer*

Ken Lamont is the Chief Financial Officer of Crescent Point, a role he has held since January 2016. Prior to that, he was Vice President, Finance and Treasurer for Crescent Point. Mr. Lamont has worked in the oil and gas industry since 2001, having held a variety of roles with companies such as Shelter Bay Energy Inc., Direct Energy Marketing Ltd. and Shell Trading Gas and Power Canada Ltd. Prior to 2001, he was a senior manager at PricewaterhouseCoopers LLP.

Mr. Lamont holds a Bachelor of Commerce degree (with distinction) from the University of Alberta, is a Chartered Professional Accountant and holds the ICD.D designation. He is a member of the Chartered Professional Accountants of Alberta and a member of the Institute of Corporate Directors.

*Ryan Gritzfeldt, Chief Operating Officer*

Ryan Gritzfeldt is the Chief Operating Officer of Crescent Point, a role he has held since 2018. Prior to that, he was Vice President, Marketing and Innovation and Vice President, Engineering and Business Development East for Crescent Point from 2010 until 2018. Additionally, he was Engineering Manager, Southeast Saskatchewan from 2006 until 2009. Mr. Gritzfeldt has worked in the oil and gas industry since 1998, having held a variety of roles with companies such as Talisman Energy Inc., in addition to Crescent Point.

Mr. Gritzfeldt is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and Saskatchewan (APEGS). He holds a Bachelor of Applied Science degree (with great distinction) in industrial systems engineering from the University of Regina.

*Brad Borggard, Senior Vice President, Corporate Planning and Capital Markets*

Brad Borggard is the Senior Vice President, Corporate Planning and Capital Markets, a role he has held since 2018. Since joining the Corporation in January 2010, he has held other senior management positions including Vice President, Corporate Planning and Investor Relations, as well as Vice President, Corporate Planning. Prior to joining Crescent Point, Mr. Borggard was Managing Director, Institutional Equity Research at CIBC World Markets from 2004 until 2009. During that time, he was ranked as the top Canadian Royalty Trust analyst four times and the top Canadian E&P analyst twice.

Mr. Borggard has worked in other oil and gas related roles, with companies such as Scotia Capital Inc. and Gulf Canada Resources Ltd. He holds a Bachelor of Commerce degree (with honours) in Finance from the University of Calgary, as well as a Chartered Financial Analyst designation.

*Mark Eade, Senior Vice President, General Counsel and Corporate Secretary*

Mark Eade is the Senior Vice President, General Counsel and Corporate Secretary at Crescent Point. Mr. Eade has served as Corporate Secretary since 2004 and was formerly Vice President, General Counsel and Corporate Secretary. Prior to being named Vice President at Crescent Point in September 2015, he was a partner with Norton Rose Fulbright Canada LLP from August 2011 to August 2015. Prior thereto, Mr. Eade was a partner at McCarthy Tetrault LLP. Mr. Eade has over 25 years of experience in corporate governance, securities and mergers and acquisitions law and has represented clients in a number of significant acquisitions and public offerings.

Mr. Eade holds a Bachelor of Commerce degree (with honours) and a LL.B. degree from the University of Saskatchewan and was called to the Alberta bar in 1994. He is a member of the Law Society of Alberta and the Canadian Bar Association.

*Garret Holt, Senior Vice President, Corporate Development*

Garret Holt is Crescent Point's Senior Vice President, Corporate Development, a role he assumed in 2019. Mr. Holt has over 30 years of experience in the oil and gas industry. Most recently, he was an Executive Director in Energy Investment Banking with JPMorgan. Prior to that, Mr. Holt held senior executive positions with Wapiti Energy as Chief Operating Officer and Fairways E&P as Senior Vice President of Exploration and Production.

He graduated from the University of Tulsa with a Bachelor of Science, Petroleum Engineering (Magna Cum Laude) and is a Registered Professional Engineer.

*Barbara Munroe, Chair of the Board*

Ms. Barbara Munroe has worked as a lawyer since being admitted to the Law Society of Alberta in 1991 and brings 27 years of legal experience and industry diversification to the Board. Prior to retiring in March 2019, Ms. Munroe served as Executive Vice President, Corporate Services and General Counsel for WestJet Airlines, a position she held since November 2016. Ms. Munroe joined WestJet in November 2011 as Vice President & General Counsel and was promoted to Senior Vice President, Corporate Services & General Counsel in June 2015. She was the Assistant General Counsel, Upstream at Imperial Oil Ltd. from 2008 to 2011 and the Senior Vice President, Legal/IP & General Counsel, Corporate Secretary for SMART Technologies Inc. from 2000 to 2008.

Ms. Munroe is a member of the Institute of Corporate Directors. She holds a Bachelor of Commerce, Finance degree and a Bachelor of Law degree both from the University of Calgary.

*Laura A. Cillis, Director*

Ms. Laura A. Cillis has 25 years of experience working in publicly traded, primarily international, organizations and has a broad range of leadership, corporate governance and financial experience. Ms. Cillis is currently a Director and member of the Audit and the Nominating & Corporate Governance committees at Western Forest Products Inc. In December 2019, she joined the board of Shawcor Ltd. and is a member of its Audit Committee.

Ms. Cillis was previously a member of and held a variety of roles on the Board of Directors for Solium Capital Inc., Enbridge Income Fund Holdings Inc. and the Enbridge Income Fund group of companies. She previously served as Senior Vice President, Finance and Chief Financial Officer for Calfrac Well Services Ltd. from November 2008 to June 2013. Prior thereto, she was the Chief Financial Officer of Canadian Energy Services L.P. since January 2006.

Ms. Cillis is a Chartered Professional Accountant, holds the ICD.D designation granted by the Institute of Corporate Directors and is a member of Financial Executives International. Ms. Cillis earned her Bachelor of Commerce degree from the University of Alberta.

*James E. Craddock, Director*

Mr. James E. Craddock is a seasoned upstream executive who possesses broad-based technical knowledge with over 30 years of experience. He has served on Noble Energy Inc.'s Board of Directors since its merger with Rosetta Resources Inc. in 2015 and served as the Chairman, Chief Executive Officer and President of Rosetta from 2013 to 2015. He is currently a member of Noble's Compensation and Corporate Governance and Nominating committees and is Chair of the Safety, Sustainability and Corporate Responsibility Committee. Previously, he was the Executive Director and Chief Operating Officer for BPI Industries Inc. and held several positions of increasing responsibility over a 20-year career at Burlington Resources Inc.

Mr. Craddock holds a Bachelor of Science in Mechanical Engineering from Texas A&M University and previously served on the Boards of Templar Energy and the Texas Railroad Commission.

*John P. Dielwart, Director*

Mr. John P. Dielwart brings a wealth of experience and knowledge to Crescent Point's Board developed through his varied 40-year career in the oil and gas sector. Most notably, Mr. Dielwart is a founding member of ARC Resources Ltd., holding the position of Chief Executive Officer from 2001 to 2013 and is currently serving as a director on its Board of Directors. He is also Vice-Chairman and a Director of ARC Financial Corp., sitting on its Investment and Governance committees where he provides leadership support on various complex issues, including internal governance and investment decision-making. Prior to joining ARC in 1996, Mr. Dielwart spent 12 years with a major

Calgary based oil and natural gas engineering consulting firm, as Senior Vice-President and a Director, where he gained extensive technical knowledge of oil and natural gas properties in Western Canada.

Mr. Dielwart has a Bachelor of Science degree in Civil Engineering with Distinction from the University of Calgary. He is a professional engineer, holds the ICD.D designation granted by the Institute of Corporate Directors and has served two three-year terms as a Governor of the Canadian Association of Petroleum Producers, including 18 months as Chair.

*Jennifer F. Koury, Director*

Ms. Jennifer F. Koury has over 35 years of professional experience, holding various senior executive positions with BHP Billiton from 2011 to 2017. Part of her responsibilities included the development of BHP Billiton's total rewards program for executives and employees of the Petroleum World-Wide Business. Prior to that, she was Vice President of Corporate Services for Enerplus Corp. from 2006 to 2011 and also held senior management positions with Imperial Oil/Exxon Mobil.

Ms. Koury serves as a Director for the Calgary Zoo and is Chair of the first public/private partnership for the United Nations Women Global Innovation Coalition for Change. She holds a Bachelor of Commerce degree from the University of Alberta and the ICD.D Directors designation granted by the Institute of Corporate Directors.

*Francois Langlois, Director*

Mr. Langlois is an oil and gas executive who brings more than 35 years of domestic and international experience to the Crescent Point Board, most recently from his role as Senior Vice President, Exploration & Production with Suncor Energy Inc., where he was responsible for the financial and operating performance of the group from 2011 until his retirement in 2016. Prior thereto, he was Vice President, Unconventional Gas from 2009 to 2010 and held various roles with Petro-Canada from 1982 to 2009, most recently as Vice President, Western Canada Production & North American Exploration.

Mr. Langlois holds a Bachelor Geological Engineering from Laval University (Quebec City).

*Ted Goldthorpe, Director*

Mr. Ted Goldthorpe is a financial professional who has been serving as Managing Partner in charge of Global Credit Business for BC Partners since February 2017. Prior thereto, he was the President of Apollo Investment Corporation, Chief Investment Officer of Apollo Investment Management, and Senior Portfolio Manager, U.S. Opportunistic Credit from April 2012 to August 2016. Previously, Mr. Goldthorpe was employed by Goldman Sachs & Co., where he held a variety of positions after joining the firm in 1999. Mr. Goldthorpe joined the Crescent Point Board in May 2017.

Mr. Goldthorpe received a B.A. in Commerce from Queen's University and is a frequent guest lecturer at leading universities across North America. Mr. Goldthorpe currently serves on the Global Advisory Board for the Queen's School of Business, is the Chairman of the Young Fellowship of The Duke of Edinburgh's Award, and serves on the board of directors for Her Justice and Capitalize for Kids.

*Mike Jackson, Director*

Mr. Mike Jackson worked in the banking industry from 1984 to 2016 and brings more than 30 years of financial experience in corporate and investment banking. Most recently, he was Managing Director - Investment Banking, Scotiabank Global Banking and Markets, with a focus on the oil and gas industry from 2008 until his retirement in 2016. Prior to that, Mr. Jackson held several senior management roles at Scotiabank, including Managing Director, Oil & Gas Industry Head & Calgary Head Office Head from 1999 to 2007 and Vice President & Office Head, Corporate Banking Calgary from 1997 to 1999.

Mr. Jackson holds a Bachelor of Science degree and a Master of Business Administration, both from Dalhousie University. Additionally, Mr. Jackson completed the Executive Management Program at Queen's University and holds the ICD.D designation granted by the Institute of Corporate Directors.

### **Bankruptcies and Cease Trade Orders**

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation is, as of the date of this AIF, or has been, within the last 10 years, been a director or executive officer of any company (including the Corporation) that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been 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 that person.

### **Penalties or Sanctions**

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

### **Personal Bankruptcies**

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the 10 years preceding the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual.

### **Share Capital**

The Corporation is authorized to issue an unlimited number of Common Shares.

### **Common Shares**

Each Common Share entitles its holder to receive notice of and to attend all meetings of the Shareholders of the Corporation and to one vote at such meetings. The holders of Common Shares are, at the discretion of the Board of Directors and subject to applicable legal restrictions, entitled to receive any dividends declared by the Board of Directors. The holders of Common Shares are entitled to share equally in any distribution of the assets of the Corporation upon the liquidation, dissolution, bankruptcy or winding up of the Corporation or other distribution of its assets among its Shareholders for the purpose of winding up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to any other shares having priority over the Common Shares.

### **Premium Dividend<sup>TM</sup> and Dividend Reinvestment Plan**

The DRIP was in effect from 2010 until August 2015, when it was suspended. Shareholders that were enrolled in the DRIP and, previously, the premium component of the DRIP when the plan and component were, respectively, suspended will remain enrolled if the DRIP is reinstated and will automatically resume participation, including in the premium component if, and when, the DRIP and such component are reinstated.

Under the Corporation's DRIP, eligible Shareholders may, at their option, reinvest their cash dividends to purchase additional Common Shares at 95% of the average market price (as defined in the DRIP) of a Common Share on the applicable distribution date. The DRIP also provides an alternative where eligible Shareholders may elect, under the premium dividend component, to receive a premium cash distribution equal to 102% of the reinvested cash dividends

that such Shareholders would have otherwise been entitled to receive on the applicable dividend date. Generally, no commissions, service charges or brokerage fees will be payable by Shareholders who participate in the DRIP. We have reserved the right to determine how much new equity is available under the Plan on any particular distribution date. Accordingly, participation in the DRIP may be pro-rated in certain circumstances.

Registered and beneficial owners of Common Shares who are not resident in Canada are not eligible to participate in the DRIP.

### **Share Dividend Plan**

The SDP was in effect from May 9, 2014 until it was suspended on August 12, 2015.

Under the terms of the SDP, eligible Shareholders may, at their option, elect to receive dividends declared on Common Shares as share dividends rather than cash dividends, where such share dividends are declared by the Board of Directors, to be payable in either cash or Common Shares at the election of the Shareholder. Share dividends are satisfied through the issuance of new Common Shares equal to the amount obtained by dividing the dollar amount of the dividend per Common Share by 95% of the average market price (as defined in the SDP) on the TSX. Generally, no commissions, service charges or brokerage fees will be payable by Shareholders who participate in the SDP. Under the SDP, we have reserved the right to determine how much new equity is available under the SDP on any particular distribution date. Accordingly, participation in the SDP may be pro-rated in certain circumstances.

Unlike the dividend reinvestment component of the DRIP, which gives only Shareholders resident in Canada the option to reinvest cash dividends into Common Shares at a 5% discount to market prices, the SDP provides all Shareholders with the option to receive dividends in the form of Common Shares at a 5% discount to current market prices. Shareholders that were enrolled in the SDP when the plan was suspended will automatically resume participation if the SDP is reinstated.

### **Restricted Share Bonus Plan**

Under the terms of the Corporation's Restricted Share Bonus Plan, any director, officer, consultant or employee of the Corporation who, in each case, in the opinion of the Board of Directors, hold an appropriate position with the Corporation to warrant participation in the Restricted Share Bonus Plan (collectively, the "**RSBP Participants**") may be granted restricted shares ("**Restricted Shares**") which vest over time and, upon vesting, can be redeemed by the holder for cash or Common Shares at the option of the Corporation. The Restricted Share Bonus Plan is administered by the Board of Directors. Under the Restricted Share Bonus Plan at December 31, 2019 the Corporation is authorized to issue up to 10,935,120 Common Shares, of which the Corporation had 3,636,194 Restricted Shares outstanding at December 31, 2019.

The Restricted Shares vest on terms up to three years from the grant date as determined by the Board of Directors. Upon redemption, the Corporation will be required to pay to the RSBP Participant the fair market value of the redeemed Restricted Shares, based on the weighted average of the prices at which the Common Shares traded on the TSX for the five trading days immediately preceding the redemption date, plus any accrued but unpaid dividend amounts in respect of such Restricted Shares (the "**Payout Amount**"). The Payout Amount may be satisfied by the Corporation making a cash payment, the Corporation purchasing Common Shares in the market and delivering such Common Shares to the RSBP Participant or by issuing Common Shares from treasury.

### **DSU Plan**

In 2012, the Corporation established a deferred share unit plan (the "**DSU Plan**") to enhance its ability to attract and retain key personnel (namely, selected officers and employees and non-employee directors) and reward significant performance achievements. Under the terms of the DSU Plan, Designated Employees and Directors (as defined in the DSU Plan), who, in the opinion of the Board of Directors, warrant participation in the DSU Plan (the "**Participants**"), may be granted deferred share units ("**Units**"). As at the date hereof, only non-employee directors have been granted DSUs.

Participants that are directors must elect to receive Units in lieu of a cash retainer prior to the year in which the retainer will be earned, unless they are elected or appointed part way through a year, in which case they must elect within 30 days of being elected or appointed to receive Units for that year. Participants that are Designated Employees must elect to receive Units in lieu of all or a portion of their annual bonus entitlement or profit share for the year within 30 days after such Designated Employee has been notified by the Corporation of such individual's bonus entitlement or profit share for such year.

The Corporation establishes an account for each Participant and all Units are credited to the applicable account as of the award date. The number of Units to be credited to an account is determined by dividing the dollar amount elected by the Participant by the five day weighted average closing price of the Common Shares on the TSX immediately prior to the award date. On the last day of each fiscal quarter of the Corporation or as soon as possible thereafter, the Corporation determines whether any dividend has been paid on Common Shares during such fiscal quarter and, if so, the rate thereof per Common Share (the "**Dividend Rate**") and, within 10 business days of the applicable fiscal month end, the Corporation credits each applicable account with an additional number of Units equal to (i) the number of Units in the applicable account on the record date for such dividend multiplied by (ii) the Dividend Rate. All Units vest immediately upon being credited to a Participant's account.

A Participant is not entitled to any payment of any amount in respect of Units until such Participant ceases to be an employee or director of the Corporation, as the case may be, for any reason whatsoever. Upon the Participant ceasing to be an employee or director of the Corporation, the Participant is entitled to receive a lump sum cash payment, net of applicable withholding taxes, equal to the product of (i) the number of Units in such Participant's account on the date the Participant ceased to be an employee or director and (ii) the five day weighted average closing price of the Common Shares on the TSX immediately prior to such date, unless the redemption event occurs during a black out period, in which case the amount of such payment will be calculated with reference to the five day weighted average closing price of the Common Shares on the TSX on the fifth business day following the end of such black out period. The Corporation will make such lump sum cash payment by the end of the calendar year following the year in which the Participant ceased to be an employee or director.

On March 10, 2015, the Board amended the DSU Plan to include provisions that govern citizens and residents in conformity with Section 409A of the U.S. Internal Revenue Code. This amendment was made to clarify and explicitly disclose certain tax consequences associated with participation in the DSU Plan by eligible U.S. citizens and U.S. residents.

### **PSU Plan**

In 2017, the Corporation adopted the PSU Plan, which is administered by the Board of Directors. The purposes of the PSU Plan are: (1) to promote alignment of interests between participants in the PSU Plan and Shareholders by providing the participants with an opportunity to participate in an increase in the equity value of the Corporation, taking into account the performance of the Corporation relative to its peers and targets established by the Board; (2) to provide participants in the PSU Plan with compensation reflective of their responsibility, commitment and risk accompanying their role over the long-term; and (3) to provide a retention incentive to participants in the PSU Plan over the long-term. Under the terms of the PSU Plan, the Compensation Committee may designate employees of the Corporation or its affiliates who are eligible to receive performance share units ("**PSUs**"). PSUs are notional grants of share-based compensation units that entitle the holder to a cash payment upon redemption of the PSU.

Unlike Restricted Shares, PSUs do not automatically vest over time. Instead, vesting is dependent on the achievement of various corporate performance metrics over a three year performance period.

The vested number of PSUs relating to a given performance period are paid out in cash based on the volume weighted average trading price of the Common Shares on the TSX over the five business days subsequent to the end of the performance period for the applicable PSUs, plus the dividends paid during the applicable performance period.

Based on underlying units prior to any effect of the performance multiplier, the Corporation had 2,920,444 PSUs outstanding at December 31, 2019.



## Stock Option Plan

The Corporation adopted the Stock Option Plan in early 2018, with the purpose of rewarding those persons who promote the growth and success of the Corporation and assisting the Corporation in attracting, motivating and retaining personnel. The Stock Option Plan was approved by the Shareholders at the Corporation's annual meeting of shareholders on May 4, 2018.

Pursuant to the terms of the Stock Option Plan, a maximum of 13,000,000 Common Shares may be issuable upon the exercise of outstanding stock options ("**Options**") granted under the Stock Option Plan (subject to adjustment for any subdivision or consolidation of the Common Shares). As at December 31, 2019, there were 2,833,342 Options to purchase Common Shares outstanding. Additionally, the number of Common Shares issuable to insiders of the Corporation (as defined in the Company Manual of the TSX) in any one year period, or at any time when combined with Common Shares issued or issuable under any of the Corporation's other security-based compensation plans, may not exceed 10% of the issued and outstanding Common Shares, and no one insider (or associates of that insider, as defined in the Company Manual of the TSX) may be issued more than 5% of the issued and outstanding Common Shares in any one year period. Non-employee directors are not entitled to participate in the Stock Option Plan. No Options shall be granted to any participant if the total number of Common Shares issuable to or on behalf of such participant under the Stock Option Plan, together with any Common Shares reserved for issuance to such participant under any other share compensation or incentive mechanism of the Corporation (which includes RSUs issued under the Restricted Share Bonus Plan) would exceed 5% of the aggregate issued and outstanding Common Shares.

The Board of Directors administers the Stock Option Plan, and will from time to time designate officers and employees of the Corporation who are entitled to participate in the Stock Option Plan, and determine the number and exercise price of Options to be granted to such participants. Non-employee directors are prohibited from participating in the Stock Option Plan. Under the Stock Option Plan, the exercise price of Options is determined by the Board of Directors at the time of grant, but will not be less than permitted by the applicable rules and policies of the TSX. Subject to the vesting provisions of the Stock Option Plan, Options may be: (i) exercised by paying the Corporation the exercise price in exchange for Common Shares; (ii) surrendered to the Corporation in exchange for a cash payment representing the aggregate difference between the market price of the Common Shares and the exercise price of the Options surrendered; or (iii) surrendered to the Corporation in exchange for a number of Common Shares equivalent in value (based on the market price) to the aggregate difference between market price of the Common Shares and the exercise price of the Options surrendered.

Unless the Board of Directors determines otherwise, Options granted pursuant to the Stock Option Plan will have a term of seven years, subject to early expiry in accordance with the change in control and other provisions of the Stock Option Plan. All Options are granted pursuant to stock option agreements executed at the time of grant by the Corporation and the grantee.

## Long-Term Debt

At December 31, 2019, the Corporation had a \$2.9 billion syndicated unsecured credit facility (the "**Syndicated Credit Facility**") and a \$100 million unsecured operating credit facility with one Canadian chartered bank (the "**Bi-Lateral Credit Facility**"). The Syndicated Credit Facility is with fourteen banks and has a maturity date of October 25, 2023. The current maturity date of the Bi-Lateral Credit Facility is October 25, 2023. The Syndicated Credit Facility's interest rate is based on either Canadian prime rate, U.S. base rate, London Interbank Offer Rate or bankers' acceptance rates at the Corporation's option subject to certain basis point or stamping fee adjustments ranging from 0.25% to 3.15% depending on the Corporation's senior debt to earnings before interest, taxes, depreciation and amortization, adjusted for certain non-cash items ("**adjusted EBITDA**") ratio. The Credit Facilities are guaranteed by certain material restricted subsidiaries currently being CPEUS, CPUSH, CPHI and the Partnership. Various borrowing options are available under the Credit Facilities, including Canadian prime rate-based advances, U.S. base rate-based advances, London Interbank Offer Rate loans and bankers' acceptance loans. The Bi-Lateral Credit Facility and Syndicated Credit Facility constitute revolving credit facilities and are extendible annually. The Credit Facilities contain standard commercial covenants for facilities of this nature. Distributions to Shareholders are not permitted if the Corporation is in default of the Credit Facilities or if the making of such distribution would cause an event of default. The Corporation does not have a

borrowing base restriction respecting its Credit Facilities. At December 31, 2019, the Corporation had approximately \$817.2 million drawn under its credit facilities.

At December 31, 2019, the Corporation had approximately \$2.1 billion of senior guaranteed notes outstanding of which \$201 million become due within one year excluding the value of underlying cross currency swaps. The senior guaranteed notes are unsecured and rank pari passu with the Corporation's credit facilities and carry a bullet repayment on maturity. The senior guaranteed notes have financial covenants similar to those of the credit facilities described above. Concurrent with the issuance of US\$1.38 billion senior guaranteed notes, the Corporation entered into cross currency swaps to hedge its foreign exchange exposure, fixing a notional amount of \$1.52 billion for the purpose of interest and principal repayments. Concurrent with the issuance of US\$30.0 million senior guaranteed notes, the Corporation entered a foreign exchange swap which fixed the principal repayment at a notional amount of \$32.2 million.

## INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas entities of similar size. All current legislation is a matter of public record, and we are unable to predict what additional legislation or amendments may be enacted.

### **New Canadian Energy Regulator**

In Canada, on August 28, 2019 the *Canadian Energy Regulator Act* replaced the *National Energy Board Act* and the National Energy Board became the Canada Energy Regulator (the "CER"). The CER now has jurisdiction over Canadian inter-provincial and international transportation of oil and gas. While the regulations created under the *National Energy Board Act* remain in force, the CER is updating existing regulations and creating new regulations through a phased approach. It is not yet known what effects the creation of the CER, and the changing regulatory landscape, will have on the Canadian oil and gas industry. The change in regulator from the NEB to the CER is not expected to have any particular effect on Crescent Point beyond the general effects on the industry.

### **Pricing and Marketing - Oil**

In Canada and the United States, producers of oil negotiate sales contracts directly with oil purchasers. Oil prices are primarily based on worldwide and North American supply and demand. The specific price paid depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance.

In the United States, transportation of crude oil is subject to rate and access regulation. The Federal Energy Regulatory Commission (the "FERC") regulates interstate crude oil pipeline transportation rates under the Interstate Commerce Act of 1887 (the "ICA"). In general, such pipeline rates must be cost-based. The FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service. Such rates and terms and conditions may not be discriminatory or preferential. At the beginning of 1995, regulations adopted by the FERC generally grandfathered all previously approved interstate transportation rates and established an indexing system for such rates permitting annual adjustments based on the rate of inflation, subject to certain limitations. Every five years, the FERC examines the annual change compared to the actual cost changes. In December 2015, under the five-year re-determination, the FERC adjusted the index level used to determine annual changes to oil pipeline rate ceilings and determined that the Producer Price Index for Finished Goods plus 1.23% should be the index level for the five-year period beginning July 1, 2016. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Intrastate crude oil pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state.

Oil exports from Canada may be made pursuant to an export contract with a term not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the CER. Any 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 licence from the CER and the issue of such a licence requires the approval of the Governor in Council.

On December 18, 2015, the U.S. Congress passed, and the President signed, legislation into law which repealed the 40-year old ban on exports of crude oil produced in the United States. Accordingly, most exports of domestically-produced crude oil may be made without an export licence. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

Beginning January 2019, in an effort to reduce a surplus of oil in storage in Alberta, the AER began curtailing oil production (the "**Curtailment**"). While production limits have been incrementally increased since the Curtailment began, in August 2019, it was announced that Curtailment would be extended by a year and would remain in effect until December 31, 2020, with the possibility for earlier termination. Curtailment is set at the operator level, which as of October 1, 2019 leaves the first 20,000 barrels per day from a given operator exempt from the Curtailment. New conventional oil wells drilled after November 8, 2019 are also exempt from production limits. As the Corporation's assets in Alberta have historically produced and continue to produce less than the threshold amount required to be subject to the Curtailment, the Corporation's production has not been physically curtailed. Therefore, while Curtailment may be having a positive effect on the price of oil produced in Western Canada, and given that a significant portion of the Corporation's production is located outside of Alberta, but is sold at a price linked to Alberta oil prices, the Corporation may be experiencing a positive effect on pricing for its production without having to physically curtail its production in Alberta.

### **Pricing and Marketing - Natural Gas**

In Canada, the price of natural gas sold intra-provincially or to the United States is determined by negotiation between buyers and sellers. In the United States, the price of sales inter-state or internationally is determined by negotiation between buyers and sellers based upon factors normally considered in the industry such as distance from well to pipeline, pressure, and quality. Natural gas exported from Canada is subject to regulation by the CER and the government of Canada and in the United States is regulated principally by the FERC and the United States Department of Energy (the "**DOE**"). The FERC, which has the authority under the Natural Gas Act of 1938 (the "**NGA**") to regulate prices, terms, and conditions for the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to FERC regulation, except interstate pipelines, to resell natural gas at market prices. In addition, under the provisions of the Energy Policy Act of 2005, the NGA was amended to prohibit market manipulation in connection with the purchase or sale of natural gas and the FERC established regulations to increase natural gas pricing transparency by requiring certain market participants to report their gas sales transactions annually to the FERC. Facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. However, the distinction between the FERC-regulated transmission facilities and federally unregulated gathering facilities is the subject of on-going litigation and, therefore, is subject to change. The FERC regulates interstate natural gas transportation rates and service conditions under the NGA and the Natural Gas Policy Act of 1978 (the "**NGPA**"), which affects the marketing of natural gas, as well as revenues we may receive for sales of our natural gas. Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies.

In both Canada and the United States, exporters are free to negotiate prices and other terms with purchasers, provided that the export contract meets certain criteria prescribed by the CER and the government of Canada or, in relation to United States exports, restrictions on export licences imposed by the DOE. Natural gas may not be imported into Canada or exported from Canada without a licence or order from the CER or imported into the United States or exported from the United States without a licence from the DOE. Licences to export or import natural gas may include various terms and conditions with respect to duration, quantity, tolerance levels, points of exportation or importation, environmental requirements, among other factors and, in Canada, may be obtained for a period that does not exceed 40 years in the case of export and 25 years in the case of import. In Canada, the approval of the Governor in Council is required prior to the issuance of a licence by the CER to import or export natural gas. Alternatively, natural gas may be imported into Canada or exported from Canada pursuant to an order from the CER. Orders may be obtained for a period of 2 years or less or for a period greater than 2 years but less than 20 years, where the quantity is not more than 30,000 m<sup>3</sup>/day. Orders do not require the approval of the Governor in Council. In the United States, the DOE regulates the exportation and importation of natural gas, including liquefied natural gas. 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's regulation of imports and exports from and to countries without such free trade agreements is more comprehensive. The FERC also regulates the construction and operation of import and export facilities.

### **The North American Free Trade Agreement and the Canada-United States-Mexico Agreement**

On January 1, 1994, the North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the U.S. and Mexico became effective. NAFTA carried forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada remained free to restrict exports to the U.S. or Mexico provided that such export restrictions did not: (i) reduce the proportion of the energy resource exported relative to the total supply of that energy resource in Canada as compared to the proportion prevailing in the most recent 36-month period, (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply. All three countries were prohibited from imposing minimum export or import price requirements except in exceptional circumstances.

NAFTA also required the parties thereto to ensure that their respective energy regulators implement any energy regulatory measures in an orderly and equitable manner and in a manner which avoids disrupting contractual relationships to the maximum extent possible.

On November 30, 2018, the governments of Canada, the U.S. and Mexico signed the Canada-United States-Mexico Agreement ("**CUSMA**"), which is intended to supersede NAFTA once it has been ratified by the legislatures in all three countries. Mexico ratified CUSMA on June 9, 2019. The U.S. House of Representatives voted to ratify CUSMA on December 19, 2019, and the U.S. Senate ratified CUSMA on January 16, 2020. Canada has yet to ratify CUSMA. If CUSMA is ratified it will likely take effect in 2020. The full effect of CUSMA on the energy industry in Canada is not yet understood, though certain changes from NAFTA to CUSMA may have a positive effect on the energy industry, including the elimination of tariffs on diluent used to transport heavy oil from Canada into the United States.

In particular, the elimination of NAFTA Article 605 (Energy Proportionality), which forbid NAFTA members from restricting access to energy and basic petrochemical products should other international market access options emerge, is a significant change under the new agreement. This is likely due to the fact that the U.S. is now nearly self-sufficient in terms of oil production and is actively pursuing other markets themselves since the lifting of the U.S. oil export ban in December 2015.

Although the new trade agreement has not yet been fully ratified by Canada, Crescent Point does not anticipate any material change to its operations or marketing activities if the new agreement is ratified.

### **Royalties and Incentives**

In addition to federal regulation, each province (and in the case of the U.S., each state) has legislation which governs land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions where we operate, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands (or in the case of the U.S., lands other than federal lands) are determined by negotiations between the mineral owner and the lessee. Crown royalties (or in the case of the U.S., federal royalties) are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity and depth, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the governments of Canada, British Columbia, Alberta, Saskatchewan and Manitoba have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. Such programs are generally introduced when commodity prices are low, and are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. These programs reduce the amount of Crown royalties otherwise payable.

### **Alberta**

In terms of oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. In respect of freehold lands, royalties are payable to the mineral owner and taxes are payable to the Province of Alberta. The Government of Alberta's approach to the royalty and tax regime is regularly reviewed for compliance with the purpose of the regimes to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees.

On January 1, 2017, Alberta adopted a new, modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "**Old Framework**") continues to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which remain subject to their pre-existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework is determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the AER on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward as the mature well's production declines.

As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Old Framework range from a base rate of 0% to a cap of 40%.

The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Subject to certain available incentives, effective from the January 2011 production month royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%.

Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

### Incentive Programs

A number of incentive programs, such as the Deep Oil Exploratory Well Program, the Enhanced Oil Recovery Royalty Program (the "**EOR Program**"), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the "**IETP**"), were created pursuant to the Old Framework.

The Deep Oil Exploratory Well Regulation provides a limited royalty exemption for qualifying exploratory oil wells spudded or deepened between January 1, 2009 and December 31, 2013 that are deeper than 2,000 metres and have a producing interval below 2,000 metres.

Under the EOR Program, the Enhanced Oil Recovery Royalty Regulation, 2014 provides that Alberta Energy may approve royalty reductions for qualifying enhanced oil recovery projects. Applications under the EOR Program ceased being accepted as of December 31, 2016; however, the EOR Program continues to apply to schemes previously approved thereunder, and will continue to so apply until December 31, 2026.

The Natural Gas Deep Drilling Regulation, 2010 provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened after May 1, 2010 and on or before December 31, 2016, with producing intervals that are deeper than 2,000 metres.

The IETP was intended to promote producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provided royalty reductions to successful applicants. Alberta Energy determined which projects qualify for the IETP, as well as the level of support that will be provided. The IETP expired on October 31, 2019.

Under the Modernized Framework, two strategic programs were introduced with the intention of promoting expanded production potential and generating long-term returns to the Province of Alberta.

The Enhanced Hydrocarbon Recovery Program (the "**EHR Program**") began January 1, 2017 and replaced the EOR Program. The EHR Program is intended to promote incremental production through enhanced recovery methods and consists of two main components. The first component targets tertiary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or other approved methods. The second component targets secondary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by waterflooding, gas cycling, gas flooding, polymer flooding or other approved methods. Under both components of the program, a company pays a flat royalty of 5 per cent on crude oil, natural gas and natural gas liquids produced from wells in an approved scheme for a limited benefit period. After the benefit period ends, wells in these schemes are subject to normal royalty rates under the Modernized Framework.

The Emerging Resources Program (the "**ERP**") began January 1, 2017. The ERP is intended to encourage industry to open up new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. For the purposes of the ERP, a project consists of a defined geographic area, target formation, set of wells and associated infrastructure. Wells that receive program benefits pay a flat royalty rate of 5 per cent until their combined revenue equals their combined program specific cost allowances established under the ERP, which will replace the standard Drilling and Completion Cost Allowance under the Modernized Framework in respect of such wells. After achieving payout of the specific cost allowance, wells are subject to normal royalty rates under the Modernized Framework.

### **Saskatchewan**

With respect to production obtained from Crown lands in the Province of Saskatchewan, the amount payable as a royalty in respect of crude oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month,

and the price of the oil. For both Crown royalty and freehold production tax purposes, crude oil is categorized by oil type as "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". Additionally, the oil in each category is subdivided according to the conventional royalty and production tax classifications as "fourth tier oil", "third tier oil", "new oil", or "old oil". The royalty reserved to the Crown depends on the categorization and classification of the oil, monthly production, and a prescribed reference price determined monthly by the Saskatchewan Ministry of Energy and Resources ("**SMER**"), formerly the Saskatchewan Ministry of Economy ("**SME**").

Similarly, the amount payable as a royalty in respect of natural gas in the Province of Saskatchewan depends on the vintage of the gas, the type of gas production, the quantity of gas produced in a month, and the price of the gas. For both Crown royalty and freehold production tax purposes, natural gas is categorized as either non-associated gas or associated gas, the former being gas produced from gas wells and the latter being gas produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as "fourth tier gas", "third tier gas", "new gas", or "old gas". The royalty reserved to the Crown depends on the categorization and classification of the natural gas, monthly production, and a reference price prescribed by the SMER. As an incentive for the production and marketing of natural gas which may otherwise have been flared, the royalty rate on associated gas is less than on non-associated natural gas.

Approximately one-fifth of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the Crown. With respect to production from freehold lands, the tax levied on oil and gas production in the Province of Saskatchewan will depend on the classification of the oil or gas and the relevant Crown royalty rate.

#### Incentive Programs

On October 1, 2002, a modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from qualifying oil wells and gas wells in the Province of Saskatchewan with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%. In addition, oil produced from Enhanced Oil Recovery ("**EOR**") projects that commenced operation prior to April 1, 2005 are subject to a cost sensitive royalty regime determined by prescribed formulas which include a number of variables and which differentiate between pre- and post-project payout. EOR projects that commenced operation on or after April 1, 2005 are also subject to a cost sensitive royalty regime that provides a royalty of 1% of gross EOR revenues prior to project payout and 20% of EOR operating income after project payout and a freehold production tax rate of 0% prior to payout and 8% of EOR operating income after payout. In respect of new waterflood projects, or expansions of existing waterflood projects, that have been approved by the minister and that commenced operation on or after October 1, 2002, the incremental oil produced from the project as a result of the waterflood operations qualifies for the "fourth tier oil" Crown royalty and freehold production tax rates.

In April of 2013, the SME announced three new drilling incentives for wells drilled on or after October 1, 2002: the vertical well drilling incentive (the "**VWDI**"); the horizontal well drilling incentive (the "**HWDI**"); and the exploratory gas well drilling incentive (the "**EGWDI**"). The VWDI provides a royalty reduction to 2.5% and a freehold production tax rate of 0% for fixed volumes drilled from exploratory vertical oil wells and deep development vertical oil wells. Exploratory vertical oil wells are wells that meet certain prescribed criteria showing the well produces oil from an area which has not generally seen production. The incentive for exploratory vertical oil wells applies to the produced volume up to 16,000m<sup>3</sup>, depending on depth. Deep development vertical oil wells are deep or deepened wells, that are not exploratory oil wells, drilled to certain prescribed zones. The incentive for these wells applies to the produced volume up to 8,000 m<sup>3</sup>. The HWDI is very similar to the VWDI, but applies to non-exploratory horizontal wells drilled on or after October 1, 2002 and provides the incentive to produced volumes up to 16,000 m<sup>3</sup>, depending on depth. Finally, the EGWDI provides a royalty reduction of the lesser of the fourth tier gas royalty rate (between 0%-5%) or 2.5% and a 0% freehold production tax rate. The incentive applies to wells that meet certain prescribed criteria which show that the well produces gas from an area from which gas has not generally been produced. The incentive applies to the produced volume up to 25,000,000 m<sup>3</sup>.

On August 1, 2019 the Government of Saskatchewan introduced the Oil and Gas Processing Investment Incentive ("**OGPII**"). OGPII offers transferable royalty and freehold production tax credits for qualified greenfield or brownfield value-added projects at a rate of 15% of eligible project costs.

## **North Dakota**

Royalties payable for oil and gas production vary depending on whether the oil and gas estate is owned by the federal government, the state government or a private landholder. Generally, the current federal royalty rate for onshore oil and gas is 12.5%. Production in North Dakota may be subject to oil and gas severance taxes, although such severance tax includes exemptions available for low-producing wells. Oil and gas produced from North Dakota state oil and gas leases is subject to royalties ranging from 1/6 to 3/16 of the net mineral interests of all oil and gas produced depending on location. Royalties payable under private oil and gas leases in North Dakota are determined by negotiations between the mineral owner and the lessee.

In response to North Dakota natural gas production reaching record highs and flaring levels exceeding the state's limit of 12%, the North Dakota Industrial Commission (the "NDIC") announced an initiative to reduce flaring and maximize the value of natural gas and natural gas liquids ("NGLs") that are co-produced with the state's oil production. On November 15, 2019, the NDIC held a public hearing on improving its gas capture strategy and promoting "regulatory clarity needed around gas gathering agreements." The NDIC seeks to avoid service interruptions on gathering lines, which have caused some of the recent excess flaring.

On April 24, 2019, Governor Bergum signed into law HB 1439, under which incremental oil produced by injecting coal-generated carbon dioxide will be exempt from oil extraction taxes. Specifically, incremental oil produced from the Bakken or Three Forks formations will be exempt for a period of 10 years, and incremental oil produced from other formations will be exempt for a period of 20 years.

## **Environmental Regulation and Protection Requirements**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, state, territorial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced or used in association with oil and gas operations, as well as requirements with respect to oilfield waste handling, storage and disposal, land reclamation, habitat and endangered species protection, and minimum setbacks of oil and gas activities from surface water bodies.

### Canada

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act*, the *Oil and Gas Conservation Act*, the *Pipeline Act*, the *Water Act* and the *Emissions Management and Climate Resilience 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, 2010*, the *Saskatchewan Environmental Code* and the *Oil and Gas Conservation Act*, which regulate harmful or potentially harmful activities and substances, any release of such substances, and remediation and abandonment obligations in Saskatchewan. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require an environmental impact assessment under the provincial *Environmental Assessment Act*. Environmental Legislation in the Province of Manitoba is, for the most part, set out in the *Environment Act* and the *Oil and Gas Act*.

Environmental legislation also requires that wells and facility sites be constructed, operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, or in the suspension or revocation of necessary licences and approvals. Crescent Point may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject Crescent Point to statutory strict liability in the event of an accidental spill or discharge from a well, pipeline or facility, meaning that fault on the part of Crescent Point need not be established if such a spill or discharge is found to have occurred.

Crescent Point estimates abandonment and reclamation costs by taking into consideration the costs associated with decommissioning, abandonment, remediation, and reclamation, all adjusted according to its working interest and



discounted in accordance with NI 51-101. Decommissioning liability cost estimates are based on information published by the AER and the AER Licensee Liability Management Program in Alberta and published by SMER in Directive PNG025 Licensee Liability Rating (LLR) Program in Saskatchewan. Crescent Point has procedures in place which address various matters including: spill prevention, response, notification, reporting, remediation and reclamation; environmental monitoring; government inspections; surface equipment spacing requirements; facility protection/security; vegetation management; surface water run-off/run-on management; groundwater; noise control; atmospheric emissions; wellsite reclamation; earthen pits; storage tanks; naturally occurring radioactive materials; disposal wells; suspended or shut-in wells; waste management; and communications.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil, or water may give rise to liabilities to third parties or regulators or result in the suspension or revocation of regulatory approvals and may require Crescent Point to incur costs to remedy such a discharge in an event not covered by Crescent Point's insurance, which insurance is in line with industry practice. Furthermore, Crescent Point expects incremental future costs associated with compliance with increasingly complex environmental protection requirements with respect to GHG emissions or otherwise, some of which may require the installation of emissions monitoring and measuring devices, the verification and reporting of emissions data and additional financial expenditures to comply with GHG emissions reduction requirements.

### United States

Our wholly-owned subsidiary, CPEUS, owns oil and natural gas properties and related assets in North Dakota and Montana in the United States. CPEUS' oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. CPEUS' operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

President Trump has indicated an intent to ease regulatory burdens on industry and on the oil and gas sector, including environmental regulations. However, any executive orders the President may issue, regulations the administration may promulgate, or any new legislation Congress may pass with the goal of reducing environmental statutory or regulatory requirements may be challenged in court. In addition, various state laws and regulations (and permits issued thereunder) will be unaffected by federal changes unless and until the state laws and corresponding permits are similarly changed, and any judicial review is completed.

The following is a summary of the more significant existing environmental, health and safety laws and regulations in the United States to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The *Comprehensive Environmental Response, Compensation, and Liability Act* (the "**CERCLA**") and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the government to file claims requiring cleanup actions, demands for reimbursement for cleanup costs, or natural resource damages, or for neighbouring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. CERCLA currently excludes petroleum from its definition of "hazardous substance", but related substances such as BTEX chemicals are listed.

The *Federal Solid Waste Disposal Act* (the "**SWDA**"), the *Resource Conservation and Recovery Act* (the "**RCRA**") and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance, as well as requirements for corrective actions. In May 2016, several environmental groups sued the Environmental Protection Agency (the "**EPA**") for failing to update its rules for management of oil and gas drilling waste under the RCRA. The petitioners requested that the EPA revise its regulations for waste materials generated as a result of oil and gas exploration and production activities. The petitioners claimed that the EPA has not reviewed or revised its regulations for management of wastes from oil and gas exploration and production operations since 1988, even though the statute requires the EPA to review and, if necessary, revise the regulations every three years. In December 2016, the court entered a Consent Decree resolving the litigation. Under the Consent Decree, the EPA agreed to propose no later than March 15, 2019 a rulemaking for revision of the regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. On April 23, 2019, the EPA issued a report detailing its finding that regulatory revisions were not necessary, satisfying the obligation under the Consent Decree. Despite this outcome there remains a risk that changes in the current RCRA exemption and comparable state laws could result in an increase in the costs to manage and dispose of wastes. Additionally, these exploration and production wastes may be regulated by state agencies as solid waste. Also, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. Although we do not believe the current costs of managing our materials constituting wastes (as they are presently classified) to be significant, any repeal or modification of the oil and gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in analogous state statutes would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Other statutes relating to the storage and handling of pollutants include the *Oil Pollution Act of 1990* (the "**OPA**"), which requires certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The OPA contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. State laws mandate oil cleanup programs with respect to contaminated soil. A failure to comply with the OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions.

The *Endangered Species Act* (the "**ESA**") seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, or destroy or modify the critical habitat of such species. Under the ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize such species or its habitat. The ESA has been used to prevent or delay drilling activities and provides for criminal penalties for willful violations of its provisions. Recent changes to the ESA, if they survive legal challenge, will change the scope of the rule's application. In August 2019, the Trump administration issued three final rules regarding implementation of the ESA. Under the new rules, the administration has changed the considerations for listing, delisting or reclassifying species. The new rules limits the framework for the term "foreseeable future," a standard used to determine whether a species is threatened, to reference a period as long as the conditions posing a danger are probable. The new rules also indicate that, when dedicating critical habitat, occupied spaces are considered first to lessen the regulatory burdens on unoccupied spaces. Unoccupied spaces must be proven essential to conservation and must contain physical or biological features essential to that species' conservation. Additionally, the final rules remove the phrase "without reference to possible economic or other impacts of such determination" of a species' status, which may open determinations for listing species to economic considerations. A second rule revised the rule related to threatened species to remove the default extension of most of the prohibitions for activities involving endangered species to threatened species, now making it a case-by-case determination. These new rules apply only towards future listing of species, but they will significantly limit the scope of the ESA and likely result in less regulatory burdens on certain unoccupied spaces. The rules are currently being challenged by environmentalists and states in court. Other statutes that provide protection to animal and plant species and that may apply to our operations include, without limitation, the *Fish and Wildlife Coordination Act*, the *Fishery Conservation and Management Act*, the *Migratory Bird Treaty Act*, and the *Bald and Golden Eagle Protection Act*.

The *National Environmental Policy Act* (the "**NEPA**") requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal and certain Indian lands would result in a "significant impact" on the environment. For purposes of NEPA, "major federal action" can be something as basic

as issuance of a required permit. For oil and gas operations on federal and certain Indigenous lands or requiring federal permits, NEPA review can increase the time for obtaining approval and impose additional regulatory burdens on the natural gas and oil industry, thereby increasing our costs of doing business and our profitability. On January 10, 2020, the White House Council on Environmental Quality (“**CEQ**”) published a Notice of Proposed Rulemaking to revise NEPA’s implementing regulations. The proposed changes to NEPA introduce a “non-major” category which will exempt certain types of governments, allowing them to move forward without an environmental assessment. The changes also propose to eliminate reference to “cumulative” effects and focus more on causation. This should limit the scope of the assessment and narrow the environmental effects associated with the proposed action to those expected as a direct outcome, rather than assessing indirect effects and their cumulative impact. CEQ’s proposed changes will make the NEPA process more efficient and timely by streamlining the entire process and proposing page and time limits. Additionally, the proposed rules introduce additional responsibilities for commenters. For example, comments will be allowed during the scoping period, and if a commenter fails to raise certain issues at the onset of the project those issues may be deemed waived. This may have the effect of less or quicker judicial review, if the issues are waived. If the proposed rules are adopted, it may result in a quicker turnaround time for obtaining leases and permits.

The *Clean Water Act* (the “**CWA**”) and comparable state statutes, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA regulates stormwater run-off from oil and natural gas facilities and requires a stormwater discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample stormwater run-off from its operations. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in waters of the United States (“**WOTUS**”) unless authorized by an appropriately issued permit.

On January 23, 2020, the EPA and U.S. Army Corps of Engineers released a final rule to define WOTUS (the “**Final WOTUS Rule**”). The Final WOTUS Rule identifies four categories as jurisdictional WOTUS: 1) the territorial seas waters that are currently used, or were used in the past, or may be susceptible to use, in interstate or foreign commerce, including waters that are subject to the ebb and flow of the tide (“**Traditional Navigable Waters**” or “**TNW**”) and any TNW that have been, are, or could be used in interstate or foreign commerce; 2) Tributaries of TNW, which are naturally occurring surface water channels that contribute perennial or intermittent flow into a TNW “in a typical year,” either directly or indirectly; 3) Ditches, which are artificial channels used to convey water that are either TNWs, constructed in a tributary, or constructed in an adjacent wetland; 4) Lakes and ponds that contribute perennial or intermittent surface flow to a TNW, tributary of a TNW, or a wetland adjacent to a TNW, or are flooded by another jurisdictional WOTUS in a typical year; 5) Impoundments of other jurisdictional WOTUS; and 6) Adjacent Wetlands, which must actually abut a jurisdictional WOTUS or have a direct hydrological surface connection to a jurisdictional WOTUS in a typical year, TNW, tributary, or lake, pond, or impoundment of a TNW.

The Final WOTUS Rule also includes twelve exclusions. Notable is that isolated wetlands and ephemeral streams, which flow from heavy rainfall are excluded, as well as water-filled depressions created in upland incidental to mining, construction or gravel pits and stormwater control features. The new definition of WOTUS narrows the jurisdictional waters and may lessen regulatory oversight for projects in certain areas.

The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. On January 11, 2017, the EPA issued the final 2017 construction general permit (“**CGP**”) for stormwater discharges from construction activities involving more than one acre, which provides coverage for a five-year period and which took effect on February 16, 2017. The 2017 CGP implements Effluent Limitations Guidelines and New Source Performance Standards for the Construction and Development Industry. The rule includes stringent restrictions on erosion and sediment control, pollution prevention and stabilization.

The *Safe Drinking Water Act* (the “**SDWA**”) and the Underground Injection Control (“**UIC**”) program promulgated thereunder, regulate the drilling and operation of subsurface injection wells. The EPA directly administers the UIC program in some states and in others the responsibility for the program has been delegated to the state. The program requires that a permit be obtained before drilling a disposal well. Violation of these regulations and/or contamination

of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Some of our operations employ hydraulic fracturing techniques to stimulate oil and natural gas production from unconventional geological formations, which entails the injection of pressurized fracturing fluids into a well bore. The federal *Energy Policy Act* of 2005 amended the SDWA to exclude hydraulic fracturing from the definition of "underground injection" under certain circumstances. However, the repeal of this exclusion has been advocated by certain advocacy organizations and others in the public. Legislation to amend the SDWA to repeal this exemption and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been introduced in Congress. In addition, the EPA at the request of Congress recently conducted a national study examining the potential impacts of hydraulic fracturing on drinking water resources. The final report, *Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States*, was issued in December 2016. The report raised some concerns regarding potential vulnerabilities in the process that could impact drinking water. However, the EPA noted that data gaps and uncertainties limited the agency's ability to draw conclusions about the impact of hydraulic fracturing activities on drinking water sources.

On May 16, 2013, the U.S. Bureau of Land Management (the "BLM") published revised proposed rules to regulate hydraulic fracturing on federal public lands and Indian lands. The proposed rules would address well stimulation operations, including requiring agency approval for certain activities, and would require certain disclosures of well stimulation fluids and other information, as well as address issues relating to flowback water. In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. In July of 2013, the BLM extended the public comment period on the proposed rules to August of 2013. On May 20, 2015 the BLM published its finalized rules on hydraulic fracturing. Following passing of the finalized rules, several states and industry groups filed suit to prevent enforcement of the rules and on September 30, 2015, a United States federal court granted a motion for a preliminary injunction preventing enforcement of the BLM's new rules, and the injunction was granted. The Obama Administration appealed the injunction. However, in light of the Trump Administration's pending repeal of the rule, the Court of Appeals for the Tenth Circuit determined that the appeals had been mooted, dismissed the appeals relating to the case, and ordered that the injunction be vacated. On December 28, 2017, BLM published a final rule rescinding the 2015 rule.

On January 10, 2019, the *Fracking Disclosure and Safety Act* (the "FDSA") was introduced in the House of Representatives. The purpose of the FDSA is to direct the BLM to issue regulations governing the use of hydraulic fracturing under oil and gas leases for federal lands. The FDSA identifies loopholes in a number of statutes that it seeks to close through increased reporting requirements, potential identification and classification of drilling waters and other wastes which should be classified as hazardous waste, and removal of certain air pollution exemptions for certain oil and gas sources. The SDWA would redefine "underground injection" to include the underground injection of fluids or propping agents pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities but excluding underground injection of natural gas for purposes of storage. Although this bill was referred to committee, and remains there, it signals a continued interest in increasing regulatory oversight of hydraulic fracturing operations.

Many states currently independently regulate hydraulic fracturing operations in the state, including North Dakota and Montana. If new federal rules or new state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business. It is also possible that our drilling and injection operations could adversely affect the environment, which could result in a requirement to perform investigations or clean-ups or in the incurrence of other unexpected material costs or liabilities.

The *Clean Air Act*, as amended, restricts the emission of air pollutants from many sources, including oil and gas operations. The *Clean Air Act* and regulations implemented thereunder regulate oil and natural gas production, processing, transmission and storage operations under the New Source Performance Standards ("NSPS") and National

Emission Standards for Hazardous Air Pollutants programs. *Clean Air Act* regulations include NSPS for completions of hydraulically fractured wells. In 2016, the EPA issued rules to curb methane emissions and reduce the release of volatile organic compounds and toxic air pollutants from new and modified oil and gas sources ("**2016 NSPS 0000a Rule**"). The final rules covered emissions from additional equipment and activities in the oil production chain, including hydraulically fractured oil wells which were not previously regulated. Additionally, the rules require owners/operators to find and repair leaks to reduce fugitive emissions, which included increasing the frequency of monitoring equipment. On March 12, 2018, the EPA issued two final amendments to certain provisions of the 2016 NSPS 0000a Rule. The amendments addressed the requirement that leaky components be repaired during unplanned or emergency shutdowns and monitoring survey requirements for well sites located on the Alaskan North Slope.

On September 24, 2019, the EPA issued a proposed rule to remove sources in the crude oil and natural gas transmission and storage segment from the source category, rescind the NSPS applicable to those sources, and rescind the methane-specific requirements of the NSPS application to sources in the production and processing segments. In the alternative, the EPA proposes to rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from the source category. The EPA indicates that these amendments will remove regulatory duplication and save the oil and gas industry US\$17 to US\$19 million a year.

The Emergency Planning and Community Right-to-Know Act ("**EPCRA**") requires certain facilities to disseminate information on chemical inventories to employees, local emergency planning committees and emergency response departments. In October 2015, the EPA indicated its intent to commence a rulemaking to add natural gas processing facilities to the list of facilities that must report under EPCRA. A proposed rule to add natural gas processing facilities to the scope of the industrial sectors covered by the reporting requirements under the EPCRA was published by the EPA in January of 2016, and the EPA accepted comments on the proposed rule until May 6, 2017. The future of this proposed rule under the Trump Administration is uncertain.

We are subject to a number of federal and state laws and regulations, including the federal *Occupational Safety and Health Act* (the "**OSHA**") and comparable state laws, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal *Superfund Amendment and Reauthorization Act* and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

We are subject to federal and state laws and regulations relating to preservation and protection of historical and cultural resources. Such laws include the *National Historic Preservation Act*, the *Native American Graves Protection and Repatriation Act*, *Archaeological Resources Protection Act*, and the *Paleontological Resources Preservation Act*, and their state counterparts and similar statutes, which require certain assessments and mitigation activities if historical or cultural resources are impacted by our activities and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements.

## **Greenhouse Gas Emissions**

### ***Carbon Policy***

In November 2015, Canada participated in the twenty first session of the Conference of the Parties of the United Nations Framework Convention on Climate Change ("**COP 21**") in Paris, France, the goal of which was to reach a new agreement for fighting global climate change. COP 21 resulted in the adoption of the Paris Agreement which made several recommendations, including: (i) holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change; (ii) increasing the ability to adapt to the adverse impacts of climate change and foster climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production; and (iii) making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development. The Paris Agreement came into force on November 4, 2016.

Over the last several years, the federal government has undertaken a number of initiatives to achieve domestic GHG reductions that align with its commitments made under the Paris Agreement. These measures include regulations,

codes and standards, targeted investments, incentives, tax measures and programs intended to directly and indirectly reduce GHG emissions.

On June 21, 2018, the Government of Canada brought into force a pan-Canadian approach to the pricing of GHG emissions under the *Greenhouse Gas Pollution Pricing Act* ("**GGPPA**"). The federal carbon pollution pricing system has two parts: (i) a trading system for large industry, known as the output-based pricing system; and (ii) a regulatory charge on fuel, commonly known as carbon tax. Each province was given the choice to either accept the federal backstop in full; create their own carbon pricing policies that meet federal standards; or a hybrid approach. Both Saskatchewan and Alberta have opted for the hybrid approach, where they have committed to develop province specific output-based pricing systems but are subject to the federal carbon tax on fuel. The federal carbon tax is applied on a broad set of fuels at \$20 per tonne of GHG emissions in 2019 and will increase by \$10 per tonne per year until it reaches \$50 per tonne in 2022.

The federal government also has a GHG emission reporting requirement under the *Canadian Environmental Protection Act, 1999* (CEPA) whereby facilities that emitted 10,000 tonnes or more of GHGs in 2018 must report their emissions to Environment and Climate Change Canada.

In Alberta, greenhouse gases ("**GHG**") emissions are regulated under the *Emissions Management and Climate Resilience Act* and the *Technology Innovation and Emissions Reduction* ("**TIER**") *Regulation*, which came into effect January 1, 2020. The TIER system is mandatory for large emitters ( $\geq 100,000$  tonnes CO<sub>2</sub>e of GHGs); however, facilities can be voluntarily registered into the system via individual opted-in facilities or creating an aggregated facility (two or more smaller facilities grouped together). Registered facilities are required to reduce their emission intensity (tCO<sub>2</sub>e/boe) by 10% based on a historical benchmark. Companies may meet these required reductions through improvements to their operations; by purchasing and retiring Alberta-based emission reduction or offset credits; by contributing to the provincial TIER Compliance Fund; or by a combination of these actions. Any facility registered into the TIER system can apply to the Canadian Revenue Agency and receive an exemption from the federal fuel surcharge (carbon tax) on applicable fuel combustion. Crescent Point has an aggregate facility registered in the TIER system.

On January 1, 2019, the Government of Saskatchewan brought into force *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations* (the "**MRGHGR**") to regulate greenhouse gas emissions in the province. As part of the MRGHGR, the Output-Based Performance Standards ("**OBPS**") were developed to reduce emissions intensity associated with fuel combustion -15% by 2030. Under the OBPS program operators of any large facility (>25,000 tCO<sub>2</sub>e) must register. Additionally, a voluntary aggregated facility (two or more smaller facilities grouped together) can also register in the OBPS program. Operators may meet these required reductions through improvements to their operations; by purchasing and retiring emission reduction or offset credits; by contributing to the provincial Technology Fund; or by a combination of these actions. Any facility registered into the OBPS can apply to the Canadian Revenue Agency and receive an exemption from the federal fuel surcharge (carbon tax) on applicable fuel combustion. Crescent Point has large emitter and aggregate facilities registered in the OBPS program.

In British Columbia, GHG emissions are regulated under the *Greenhouse Gas Emission Reporting Regulation* enacted pursuant to the *Greenhouse Gas Industrial Reporting and Control Act* which imposes GHG emissions reporting requirements upon B.C. facilities emitting 10,000 tonnes or more of GHG emissions per year. Facilities that emit 25,000 tonnes or more of GHGs must have their emission reports verified by an accredited third party. Crescent Point does not operate any facilities that are regulated by the British Columbia GHG emissions regulations.

## **U.S. Greenhouse Gas Emissions Regulation**

In the United States, on December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has begun adopting and implementing regulations that restrict GHG emissions under existing provisions of the *Federal Clean Air Act* (the "**CAA**"), including one rule that limits GHG emissions from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger the CAA construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("**PSD**")

and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. However, based on a decision of the U.S. Supreme Court, only facilities already required to obtain PSD permits for other criteria pollutants must also reduce GHG emissions that exceed certain thresholds consistent with guidance for determining "best available control technology" standards for GHG, which guidance was published by the EPA in November 2010. Also, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011.

In June 2014, the Supreme Court upheld most of the EPA's GHG permitting requirements, allowing the agency to regulate the emission of GHG from stationary sources already subject to the PSD and Title V requirements. Certain of our equipment and installations may currently be subject to PSD and Title V requirements and, hence, under the Supreme Court's ruling, may also be subject to the installation of controls to capture GHG. For any equipment or installation so subject, we may have to incur increased compliance costs to capture related GHG emissions. In October 2016, the EPA proposed revisions to the rule applicable to GHGs for PSD and Title V permitting requirements. The proposed rule has not been finalized.

In addition, both houses of Congress have actively considered legislation to reduce GHG emissions and many states have already taken legal measures to reduce GHG emissions, primarily through the development of GHG inventories, greenhouse gas permitting and/or regional GHG "cap and trade" programs. Most of these "cap and trade" programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. In the absence of new legislation, the EPA has issued new regulations that limit GHG emissions associated with our operations which will require us to incur costs to inventory and reduce GHG emissions associated with our operations and which could adversely affect demand for the oil and natural gas that we produce.

On November 4, 2019, the U.S. initiated the formal process to withdraw from the Paris Agreement. Withdrawal is expected to take effect in one year. The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic United States regulations. Following the initiation of the U.S. withdrawal from the Paris Agreement, state and local climate regulatory efforts are expected to increase. In several U.S. states, the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to oil and gas facilities. The earliest date for the complete withdrawal of the United States from the Paris Agreement is November 4, 2020.

### ***Methane Policy***

On June 29, 2016, Canada joined the United States and Mexico in agreeing to reduce methane emissions from the oil and gas sector by up to 45% by 2025 from 2014 levels by developing and implementing federal regulations for both existing and new sources of venting and fugitive methane emissions. Previously, on March 10, 2016, Canada and the United States committed to take action on methane emissions through federal regulations as expeditiously as possible. The United States has since cancelled their participation in this initiative.

On January 1, 2020, the Canadian federal government implemented the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*. The regulation imposes both facility and equipment level requirements. Facilities that produce 60,000 m<sup>3</sup> of hydrocarbon gas annually in any of the past five years and facilities using pneumatic devices or compressors are covered by the regulations, as well as certain hydraulic fracturing activities.

On January 1, 2020, the Canadian federal government implemented the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*. The federal regulations that apply to methane in the upstream oil and gas sector aim to control methane emissions and also reduce the amount of volatile organic compounds (VOCs) released into the air. These regulations apply generally to facilities that handle significant volumes of gas (facilities that produce or receive a combined volume of 60,000 m<sup>3</sup> of hydrocarbon gas or greater annually in any of the past five years). The regulations outline regulatory

requirements for fugitive equipment leaks, venting from well completions, and compressors, which come into force on January 1, 2020 and requirements for facility production venting restrictions and venting limits for pneumatic equipment, which come into force on January 1, 2023.

Beginning in 2020, operators of upstream oil and gas facilities will be required to; 1) implement a leak detection and repair program to stop natural gas leaks three times per year on facilities that produce or receive a combined volume of 60,000 m<sup>3</sup> of hydrocarbon gas or greater annually; 2) complete annual measurements of emissions from natural gas compressor vents to ensure emissions are under the applicable limit; and 3) eliminate venting from well completions involving hydraulic fracturing.

Beginning in 2023, operators of upstream oil and gas facilities will be required to; 1) meet a venting limit of 15,000m<sup>3</sup> of gas per year at facilities that produce and/or receive more than 60,000m<sup>3</sup> of gas per year, and; 2) limit venting from pneumatic devices to a maximum threshold.

All upstream oil and gas facilities to which the federal regulations apply are required to register and to keep records in order to demonstrate compliance with the proposed regulations. Facility operators are also required to submit reports at the request of the federal Minister of Environment.

The federal regulations will not apply in provinces which the federal government deems to have equivalent methane reduction regulations. As of January 1, 2020, Alberta and Saskatchewan governments are working toward achieving equivalency but have not formally reached an equivalency agreement with the federal regulations. Currently operators of these provinces are subject to dual regulation under the provincial and federal frameworks.

In Alberta, new design specifications have been put in place by the Alberta Energy Regulator (the "AER") for oil and gas wells, pipelines and facilities as well as standards for key equipment and operational best practices. Fugitive emission standards are also included in the regulatory requirements and will raise current standards for performance, monitoring, measurement and reporting. The AER has published directives requiring methane emission reductions commencing January 1, 2020.

On January 1, 2019, the Government of Saskatchewan brought into force *The Oil and Gas Emissions Management Regulations* to reduce methane emissions from upstream oil and gas companies with emissions of more than 50,000 tonnes of GHGs per year from oil facilities. Every company subject to the regulation must ensure GHG emissions from flaring and venting are below provincial limits or pay an administrative penalty if they fail to do so.

The Government of Canada's GHG regulations apply to some of Crescent Point's operations and as a result additional costs are being incurred to comply with carbon pricing, GHG emission reduction requirements and to perform necessary monitoring, measurement, verification and reporting of GHG emissions. Further, our operations in British Columbia, Alberta and Saskatchewan are subject to provincial GHG emissions controls or reduction requirements.

Crescent Point anticipates current and future environmental legislation will require reductions in emissions from its operations and result in increased capital and operational expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition and results of operations.

We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures as a result of the increasingly stringent laws relating to the protection of the environment. Our internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding.

### **Abandonment and Reclamation Costs**

As at December 31, 2019, Crescent Point owned approximately 20,927 gross (17,160 net) producing, non-producing, abandoned wells for which abandonment and/or reclamation costs are expected to be incurred. During the 2019 financial year, Crescent Point spent approximately \$28.7 million on well abandonments and environmental reclamation activities. Crescent Point estimates that it will spend approximately \$35.0 million on well abandonments and environmental reclamation activities in 2020 and has budgeted accordingly. Crescent Point has estimated the net



present value (discounted at approximately 1.75% per annum) of its total decommissioning liability (wells and facilities) to be approximately \$1.14 billion as at December 31, 2019, based on estimated undiscounted cash flows of approximately \$1.09 billion.

### **Health, Safety and Environment**

The health and safety of employees, contractors, visitors and the public, as well as the protection of the environment, is of the utmost importance to Crescent Point. The Corporation endeavors to conduct its operations in a manner that will minimize both adverse environmental effects and consequences of emergency situations by:

- Complying with all applicable government regulations and standards;
- Operating in a manner consistent with industry codes, practices and guidelines;
- Ensuring prompt and effective response and repair to emergency situations and environmental incidents;
- Providing training to ensure compliance with Crescent Point's Operations Management System;
- Careful planning, good judgment and prudent monitoring of the Corporation's activities;
- Communicating openly with all stakeholders regarding our activities; and
- Amending Crescent Point's policies and procedures, as may be required from time to time.

Crescent Point believes that it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. Crescent Point's practice is to do all that it reasonably can to ensure that it remains in material compliance with applicable environmental protection legislation. Crescent Point also believes that it is reasonably likely that the trend towards stricter standards in environmental regulation will continue. Crescent Point is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. Crescent Point anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, the development or exploration activities, or otherwise adversely affect Crescent Point's financial condition, capital expenditures, results of operations, competitive position or prospects.

## RISK FACTORS

Each of the risks described below should be carefully considered, together with all of the other information contained herein, before making an investment decision with respect to our Common Shares. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you could lose all or part of your investment.

### Risks Relating to Our Business

***Our estimated Proved and Proved plus Probable reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.***

The reserve and recovery information contained in the Crescent Point Reserve Report are only estimates and the actual production and ultimate reserves from our properties may be greater or less than the estimates prepared by GLJ and Sproule. Ultimately, actual reserves attributable to our properties will vary from estimates, and those variations may be material. The reserve figures contained herein are only estimates. The estimation of reserves is an inherently complex process requiring significant judgment. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- future commodity prices, production and development costs, royalties and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- success of future development activities;
- marketability of production;
- availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities;
- effects of government regulation and the Curtailment; and
- other government levies that may be imposed over the producing life of reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the relevant evaluations were prepared. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change. See "*Special Notes to Reader*". Many of these factors are subject to change and are beyond our control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates and such variations may affect the market price of our Common Shares and payments of dividends to Shareholders.

### ***Dividends on the Corporation's Common Shares are variable.***

Dividends may be reduced or eliminated in the sole discretion of the Board of Directors. For example, dividends may be reduced or eliminated during periods in which we make capital expenditures or debt repayments using cash flow, which could also affect the market price of our Common Shares. To the extent that we use cash flow to finance acquisitions, development costs and other significant expenditures, the net cash flow the Corporation receives that is available for dividends to Shareholders will be reduced. Hence, the timing and amount of capital expenditures may affect the amount of net cash flow received by the Corporation and, as a consequence, the amount of cash available to distribute to Shareholders. Therefore, dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

The Board of Directors has the discretion to determine the extent to which cash flow from Crescent Point will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the Credit Facilities. As a consequence, the amount of funds used to pay debt service charges or reduce debt will reduce the amount of cash available for dividends to Shareholders during those periods in which funds are so retained.

***The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems.***

Our business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and rail loading facilities and railcars. Canadian federal and provincial, as well as U.S. federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, changes in supply and demand and changes in pipeline ownership or operation could adversely affect our ability to produce or market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which may affect the market price of our Common Shares and reduce dividends to our Shareholders.

***Our future performance depends on our ability to acquire additional natural gas and oil reserves that are economically recoverable.***

If we are unable to acquire additional reserves, the value of our Common Shares and payments of dividends to Shareholders may decline. We add to our oil and natural gas reserves primarily through development, exploitation and acquisitions including those with large resource potential. As a result, future oil and natural gas reserves are highly dependent on our success in exploiting existing properties and acquiring additional reserves. We cannot guarantee that we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and, as a consequence, either production from, or the average reserve life of, our properties may decline. Either decline may result in a reduction in the value of our Common Shares and in a reduction in cash available for dividends to Shareholders.

***The properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the acquired properties or obtain protection from sellers against such liabilities.***

The properties we acquire may not produce as expected, may be in an unexpected condition and we may be subject to increased costs and liabilities, including environmental liabilities. Although we review properties prior to acquisition in a manner consistent with industry practices, such reviews are not always capable of identifying all potential adverse conditions. Furthermore, we may not be able to subject the preparation of reserve estimates for acquired properties to the same internal controls we have for the preparation of reserve estimates for our existing properties. Generally, it is not feasible to review in depth every individual property involved in each acquisition. We focus our review efforts on the higher-value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties and preparation of reserve reports in accordance with our internal controls may not necessarily reveal existing or potential problems or permit us to become sufficiently familiar with the properties to fully assess their condition, any deficiencies, and development potential.

***Increases in operating costs could adversely affect our business, financial condition and results of operations.***

An increase in operating costs could have a material adverse effect on our results of operations and financial condition and, therefore, could reduce our ability to pay down debt, reduce dividends to Shareholders as well as affect the market price of the Common Shares.

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by the Corporation and, therefore, may reduce dividends to our Shareholders. Electricity, chemicals, supplies and labour costs are a few of the operating costs that are susceptible to material fluctuation.

***The operation of a portion of our properties is largely dependent on the ability of third party operators.***

Some of our properties are not operated by us and, therefore, results of operations may be adversely affected by the failure of third-party operators, which could affect the market price of our Common Shares and dividends to Shareholders.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of those properties. At December 31, 2019, approximately 7% of our daily production was

from properties operated by third parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, our revenue may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements which govern the properties not operated by us typically require the operator to conduct operations in a good and "workmanlike" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operated working interest owners for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or willful misconduct.

***Delays in business operations could adversely affect our income and financial condition.***

Delays in business operations could adversely affect dividends to Shareholders, our income, our financial condition and the market price of our Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline, railcar, trucking or refinery capacity;
- blowouts or other accidents;
- the effects of and response to COVID-19 (Coronavirus);
- blockades and social unrest;
- accounting delays;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these or other delays in our business operations could reduce our income, the amount of cash available for dividends to Shareholders in a given period, our financial condition and could expose us to additional third party credit risks.

***Failure to realize anticipated benefits of prior acquisitions and dispositions may have a material adverse effect on our business.***

The Corporation has completed a number of acquisitions and dispositions in order to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits, including, among other things, potential cost savings. In order to achieve the benefits of these and future acquisitions the Corporation is dependent upon its ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Corporation. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of such prior acquisitions. Dispositions may fail to provide anticipated benefits as the employment of capital received from any such dispositions will be subject to the risks the Corporation faces. Such capital may fail to deliver a return commensurate or greater than the return formerly garnered from the disposed assets.

***Failure of third parties to meet their contractual obligations to us may have a material adverse effect on our financial condition.***

Although the Corporation monitors the credit worthiness of third parties it contracts with through a formal Risk Management and Counterparty Credit Policy and maintains third party trade credit insurance, there can be no assurance that the Corporation will not experience a loss for non-performance by any counterparty with whom it has

a commercial relationship. Such events may have material adverse consequences on the business of the Corporation and may limit the timing or amount of dividends that are paid to Shareholders and could affect the market price of our Common Shares.

***Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, ability to return capital to shareholders, results of operations, cash flows and business prospects.***

We may, from time to time, finance a significant portion of our operations through debt. Our indebtedness may limit the timing or amount of capital returns to Shareholders, and could affect the market price of our Common Shares.

The payments of interest and principal, and other costs, expenses and disbursements to our lenders reduces amounts available for return to Shareholders. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flow required to be applied to the debt before payment of any amounts to the Shareholders. The agreements governing our long-term debt provide that, if we are in default or fail to comply with certain covenants, we must repay the indebtedness at an accelerated rate, and the ability to return capital to Shareholders may be restricted. Significant reductions to cash flow or increases in drawn amounts under the Credit Facilities may result in the Corporation breaching its debt covenants under the agreements governing its long-term debt. If a breach occurs, there is a risk that the Corporation may not be able to negotiate covenant relief with one or more of its long-term debt counterparties. Failure to comply with debt covenants or negotiate relief may result in its indebtedness under the Credit Facilities or senior guaranteed notes becoming immediately due and payable, which may have a material adverse effect on the Corporation's operations and financial condition.

***Increased costs of capital could adversely affect our business.***

Our business and operating results could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows and place us at a competitive disadvantage. Disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

***Our existing credit facilities and any replacement credit facilities may not provide sufficient liquidity.***

Our current 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. The interest charged on our Syndicated Credit Facility is calculated based on a sliding scale ratio of the Corporation's senior debt to adjusted EBITDA ratio. Repayment of all outstanding amounts under the Syndicated Credit Facility may be demanded on relatively short notice if an event of default occurs and is continuing. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and dividends to Shareholders may be materially reduced.

***We may incur losses as a result of title defects in the properties in which we invest.***

Unforeseen title defects may result in a loss of entitlement to production and reserves. Although we conduct title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat our title to the purchased assets. If such a defect were to occur, our entitlement to the production from such purchased assets could be jeopardized and, as a result, dividends to Shareholders may be reduced.

***Aboriginal claims could have an adverse effect on us and our operations.***

The economic impact on us of claims of aboriginal title is unknown. Aboriginal people have claimed aboriginal title and rights to a substantial portion of western Canada and the U.S. We are unable to assess the effect, if any, that any

such claim would have on our business and operations. Current protests affecting transportation and other infrastructure in Canada, if continued, may have a negative impact on the Corporation's ability to sell its products.

***Hedging limits participation in commodity price increases and increases counterparty credit risk exposure.***

We periodically enter into hedging activities with respect to a portion of our production to manage our exposure to oil and gas price volatility. To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from fully realizing the benefits of commodity price increases above the prices established by our hedging contracts. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the contract counterparties fail to perform under the contracts.

***Our information assets and critical infrastructure may be subject to cyber security risks.***

The Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Although the Corporation has security measures and controls in place that are designed to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws and a disruption to its business activities. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Crescent Point relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data. In addition, information systems could be damaged or interrupted by natural disasters, *force majeure* events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on Crescent Point's business, financial condition, results of operations and cash flows.

***We depend upon our management team and our operations require us to attract and retain experienced technical personnel.***

Shareholders are entirely dependent on our management with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves and the management and administration of all matters relating to our oil and natural gas properties. The loss of the services of key individuals who currently comprise the management team could have a detrimental effect on the Corporation. Additionally, COVID-19 (Coronavirus) may disrupt the ability of our management team to provide services.

***We operate only in western Canada and the United States and expansion outside of these areas may increase our risk exposure.***

If we expand our operations beyond oil and natural gas production in western Canada, North Dakota and Montana, we may face new challenges and risks. If we were to be unsuccessful in managing these challenges and risks, our results of operations and financial condition could be adversely affected, which could affect the market price of our Common Shares and payment of dividends to Shareholders.

Our operations and expertise are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin and in North Dakota and Montana. In the future, we may acquire oil and gas properties outside this geographic area. In addition, we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present challenges and risks

that we have not faced in the past. If we do not manage these challenges and risks successfully, our results of operations and financial condition could be adversely affected.

***We may be the subject of litigation.***

From time to time, the Corporation may be the subject of litigation. Claims under such litigation may be material. The types of claims the Corporation may face include, without limitation, claims for breach of contract, environmental damage, negligence, product liability, tax, patent infringement and employment matters. The outcome of any such litigation is not certain, but may materially impact Crescent Point's financial condition or results of operations. Crescent Point may also be subject to adverse publicity related to such claims, regardless whether Crescent Point is ultimately found responsible. In addition, the Corporation may be required to incur significant expenses or devote significant resources defending any such litigation.

**Risks Relating to the Oil and Gas Industry**

***Oil and Natural gas prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.***

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Lower commodity prices may reduce the amount of oil and natural gas that we can produce economically. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results and could result in impairment charges.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include but are not limited to the following:

- the levels and location of oil and natural gas supply and demand and expectations regarding supply and demand;
- the level of consumer product demand;
- the impacts of COVID-19 (Coronavirus) and response;
- weather conditions;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East, Africa, Russia and South America;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- the price level of foreign imports;
- actions of governmental authorities, including the Curtailment;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for oil and natural gas;
- blockades of transportation infrastructure and civil unrest;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices; and
- overall economic conditions, including the value of the U.S. dollar relative to Canadian and other major currencies.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of crude oil and natural gas. If crude oil and natural gas prices remain significantly depressed for a sustained

period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

***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 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 in dividends to Shareholders and/or the market price of the Common Shares.

Fluctuations in foreign currency exchange rates could adversely affect our business, and could affect the market price of our Common Shares and payments of dividends to Shareholders. The price that we receive for a majority of our oil and natural gas is based on U.S. dollar denominated benchmarks and, therefore, the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the U.S. dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given U.S. dollar price. Conversely, a material decrease in Canadian versus U.S. dollar values would reduce the Corporation's ability to develop the U.S. asset base. Each of these situations may negatively impact future dividends and the future value of the Corporation's reserves as determined by independent evaluators. We could be subject to unfavourable exchange rate changes to the extent of our investment in U.S. subsidiaries and to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

***Competition in the oil and gas industry is intense, which may adversely affect our ability to compete.***

The oil and natural gas industry is highly competitive. We compete for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than we do. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of our competitors may have greater and more diverse competitive resources to draw on than we do. Given the highly competitive nature of the oil and natural gas industry, this could adversely affect the market price of our Common Shares and dividends to Shareholders.

***Risks associated with the production, gathering, transportation and sale of oil and natural gas could adversely affect net income and cash flows. We may not be insured against all of the operating risks to which our business is exposed.***

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance. Our operations are subject to all of the risks associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells, and the production and transportation of oil and natural gas. These risks include encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires, spills and explosions. A number of these risks could result in personal injury, loss of life, or environmental and other damage to our property or the property of others and reputational loss. We cannot fully protect against all of these risks, nor are all of these risks insurable. We may become liable for damages arising from these events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for payment of dividends to Shareholders.

***We are subject to complex laws that can affect the cost, manner or feasibility of doing business.***

Crescent Point is subject to extensive and complex regulations and laws enforced by various regulatory agencies. These regulatory agencies include, in Canada, the AER, AEP, the British Columbia Oil and Gas Commission, British Columbia Ministry of Environment, the SMER, the Manitoba Ministry of Conservation, Environment and Climate Change Canada, Health Canada, Transport Canada and the Department of Fisheries and Oceans, the CER, and, in the



U.S., the EPA, the U.S. Bureau of Indian Affairs, and the BLM, Energy and Minerals. Crescent Point is also subject to regulation by other federal, provincial, state and local agencies. Regulations affect almost every aspect of Crescent Point's business and limit its ability to make and implement independent management decisions, including about business combinations, disposing of operating assets and engaging in transactions between Crescent Point and its affiliates.

Under these laws and regulations, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our financial condition and results of operations.

Regulations and laws are subject to ongoing policy initiatives, and Crescent Point cannot predict the future course of regulations or legislation and their respective ultimate effects. Such changes could materially impact Crescent Point's business, financial position and results of operations.

For further discussion about the effect of environmental laws and regulations, see below "*Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations*".

***Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations.***

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that Crescent Point may be in non-compliance with an environmental law, regulation, permit, licence or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose Crescent Point to fines or penalties, suspension or revocation of regulatory permits, third party liabilities or to the requirement to remediate or carry out other actions, the costs of which could be material. The operational hazards associated with possible blowouts, accidents, oil spills, gas leaks, fires, explosions or other damage to a well, pipeline or facility may require Crescent Point to incur costs and delays to undertake corrective actions, and could result in penalties and fines and suspension or revocation of regulatory approvals or environmental or other damage for which Crescent Point could be liable. Oil and gas operations are also subject to specific operational risks which may have a material operational and financial impact on Crescent Point should they occur, such as drilling into unexpected formations or unexpected pressures, premature decline of reservoirs and water invasion into producing formations.

Crescent Point may also be subject to associated liabilities, resulting from lawsuits alleging property damage or personal injury brought by private litigants related to the operation of Crescent Point's facilities or the land on which such facilities are located, regardless of whether Crescent Point leases or owns the facility, and regardless of whether such environmental conditions were created by Crescent Point, a prior owner or tenant, a third party or a neighbouring facility whose operations may have affected Crescent Point's facility or land. Such liabilities could have a material adverse effect on Crescent Point's business, financial position, operations, assets or future prospects.

Crescent Point also faces uncertainties related to future environmental laws and regulations affecting its business and operations. Existing environmental laws and regulations may be revised or interpreted more strictly, and new laws or regulations may be adopted or become applicable to Crescent Point, which may result in increased compliance costs or additional operating restrictions, each of which could reduce Crescent Point's earnings and adversely affect Crescent Point's business, financial position, operations, assets or future prospects.

Compliance with environmental laws and regulations could materially increase our costs. We may incur substantial capital and operating costs to comply with increasingly complex laws covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with future federal GHG emissions reduction requirements or other GHG emissions regulations. See below "*Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for oil and gas that we produce*".

Although we record a provision in our consolidated financial statements relating to our estimated future abandonment and reclamation obligations, we cannot guarantee that we will be able to satisfy our actual future abandonment and

reclamation obligations. In addition, estimates of the costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. Although the Corporation maintains insurance consistent with prudent industry practice, we are not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms.

Accordingly, our properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to Crescent Point. Any site remediation, reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of our reclamation fund and, if required, out of cash flow and, therefore, will reduce the amounts available for payment of dividends to Shareholders. Should we be unable to fully fund the cost of remedying an environmental problem, we might be required to suspend or terminate certain operations or enter into interim compliance measures pending completion of the required remedy.

Numerous governmental authorities, such as the U.S. EPA, and analogous state agencies, including in North Dakota and Montana, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of Crescent Point's operations.

***Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for oil and gas that we produce.***

Complying with the GGPPA could result in increased operating costs as we adjust to the new fuel charges potentially imposed by the GGPPA. Additionally, complying with methane reduction regulations applicable to our business could result in Crescent Point incurring additional operating costs to in order to achieve compliance.

In Saskatchewan, it is not currently possible to predict the specific changes or the impact that the MRGHGA will have on the business, operations and/or finances of Crescent Point. Changes to federal legislation, as well as legislation in British Columbia, Alberta and Saskatchewan require the restriction or reduction of GHG emissions or emissions intensity from our current and future operations and facilities, which may lead to increased operational costs associated with emission reductions, payments to technology funds, payments of carbon levies, the purchase and retirement of emission reductions or offset credits, or a combination of such actions. The required GHG reductions may not be technically or economically feasible for our operations and the failure to meet such emission reduction or emission intensity reduction requirements or other compliance mechanisms may materially adversely affect our business and result in fines, penalties and the suspension of some operations. As well, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other compliance methods of reducing emissions or emission intensity to levels required in the future may significantly increase our operating costs or reduce output. Emission reductions or offset credits may not be available on an economic basis.

The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic United States regulations. However, we may face increased and material costs as a result of GHG regulation in the U.S. Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in precipitation and extreme weather events. In addition, warmer winters in some regions as a result of climate change could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are realized due to climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

***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 yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

***Federal, provincial, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.***

Some of Crescent Point's operations use hydraulic fracturing, which involves the high pressure injection of fluids and sand down a well to fracture the reservoir and thereby stimulate the increased flow of oil or gas into the well bore. Hydraulic fracturing has been the subject of greater regulatory and public scrutiny and regulation in certain jurisdictions of the world, including some of the areas in which Crescent Point operates. In a limited number of areas, hydraulic fracturing has been banned pending public and scientific reviews or is subject to moratoria while regulators study the practice. We may be required to expend additional costs to comply with future regulatory requirements with respect to hydraulic fracturing or, in the future, be unable to carry out hydraulic fracturing operations, thereby lessening the volume of oil and gas we could otherwise produce and this could have a material operational and financial impact on Crescent Point and adversely affect the market price of our Common Shares and dividends to Shareholders.

***Uncertainty resulting from the Orphan Well Association v Grant Thornton Ltd. court decision.***

On January 31, 2019, the Supreme Court of Canada released its decision in *Orphan Well Association v Grant Thornton Ltd.* (the "**Redwater decision**") overturning earlier decisions of the Alberta Court of Queen's Bench and the Alberta Court of Appeal to hold that receivers and trustees can no longer avoid the AER legislated authority to: (i) impose abandonment orders against licensees, or (ii) require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. As a result, any financial resources of a bankrupt licensee in Alberta will first be used to satisfy outstanding abandonment obligations in respect of its unproductive assets. Remaining amounts, if any, will then satisfy the claims of secured creditors in accordance with the *Bankruptcy and Insolvency Act*. As a result of the Supreme Court of Canada's decision, the provincial regulation of environmental liabilities and associated decommissioning liability in the oil and gas industry may face substantial changes in the near future. There remains some uncertainty as to what regulatory measures will be developed by the provinces, either on a province-by-province basis or in concert with the federal government to address the *Orphan Well Association v Grant Thornton Ltd.* decision. The impact of any such regulatory measures on the Corporation is uncertain at this time.

Additionally, some issuers have been required by lenders to include covenants with respect to the asset recovery obligations in the agreements that govern their borrowings (including credit facilities and other debt obligations) following the Redwater decision. To date the Corporation has not been required by its lenders to include such provisions, however, there can be no certainty that the Corporation's lenders will not require such or other covenants and contractual terms, which in turn could cause the Corporation's risk and/or cost of borrowing to increase, possibly materially.

***Safety requirements involving rail transportation may adversely affect us and our Shareholders.***

In response to train derailments occurring in the United States and Canada in 2013, U.S. and Canadian regulators have implemented new rules to address the safety risks of transporting crude oil by rail.

In Canada, amendments have been made to the *Transportation of Dangerous Goods Regulation* which adopt a new class of tank car for flammable liquid dangerous goods service and which require all new rail tank cars destined for flammable liquid service to be built to the new specifications. Certain older tank cars used to transport crude oil have been phased out. Further, shippers of crude oil by rail now must have in place an Emergency Response Assistance Plan approved by the Minister of Transportation in order to be able to provide assistance to responders in the event of an accident. Other amendments require the consigner of a shipment of crude oil by rail to properly classify the crude oil and to certify that the classification is correct. Additionally, Transport Canada has introduced requirements

for railway companies to reduce the speed of trains carrying dangerous goods such as crude oil and to implement various other safe operating practices.

In the United States, the Department of Transportation finalized new regulations in May 2015 for the transportation of flammable liquids, which align with the standards adopted by Canada. The final rule creates a new, enhanced tank car standard and an accelerated retrofitting schedule for older tank cars. The rule requires enhanced braking systems on trains transporting flammable liquids, restricts operating speeds, requires a risk assessment-based routing analysis, and mandates procedures for more accurate classification of crude oil. On December 4, 2015, the FAST Act came into force, which among other things, established a mandatory phase-out schedule for older tank cars.

These regulations and the adoption of any other regulations that impact the testing or rail transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favourable prices at market centers throughout Canada and the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

***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.***

Changes in tax and other laws may adversely affect the trading price of our Common Shares and dividends to Shareholders. Tax authorities having jurisdiction over the Corporation or the 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 Shareholders.

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, the provinces, the United States, and the various states, all of which should be carefully considered by investors in the oil and gas industry. All of 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 or results of operations or prospects and our ability to maintain dividends to Shareholders.

***Royalty changes may adversely affect us.***

Royalty frameworks, including rates and available incentive programs, may be reviewed and amended from time to time by the applicable federal, provincial, state or other governmental bodies or agencies having jurisdiction. In addition, the royalty rates applicable to the Corporation's production of hydrocarbons may be impacted by changes in market prices for hydrocarbons, production volumes, and capital and operating costs. An increase in royalty rates would reduce the Corporation's cash flow and earnings, and could make future capital investments, or the Corporation's operations, less economic.

***We are affected by seasonal weather patterns.***

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities, provincial and state transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors, unexpected weather patterns, wildfires and floods may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

***Potential for environmental non-governmental organization legal challenges.***

Given that the U.S. government has not addressed climate change concerns, including, for example, a protracted delay by President Trump's administration in determining its own carbon-cost estimate (i.e., the estimate of how much carbon pollution costs society via climate damages) after rejecting the \$40 per ton of carbon dioxide equivalent estimate of the Obama administration, environmental non-governmental organizations additional opportunities to pursue further legal challenges to oil and gas drilling and pipeline projects.

**Risks Relating to Ownership of our Common Shares**

***Our Board of Directors has discretion in the payment of dividends and may choose not to maintain dividends in certain circumstances.***

Any future dividends will be reviewed by the Board of Directors and adjusted from time to time to reflect current business conditions. The ability of the Corporation to pay dividends and the actual amount of such dividends will be dependent upon, among other things, the financial performance of the Corporation and its subsidiaries, its debt covenants and obligations, its ability to refinance its debt obligations on similar terms and at similar interest rates, its working capital requirements, its future tax obligations and its future capital requirements. A reduction in the amount of cash distributed to Shareholders may negatively affect the market price of the Common Shares.

***Availability of Future Debt and Equity Financing.***

The success of Crescent Point's business in the future is dependent on its ability to obtain debt and equity financing to maintain its operations. Crescent Point continues to invest in property, plant and equipment to grow its operations. This investment requires adequate financing that Crescent Point obtains through both internal operating cash flows and external debt and equity financings. There can be no assurance additional financing will be available in the future when needed or on terms acceptable to Crescent Point. The inability to access financing to support future growth opportunities could limit Crescent Point's operations and have a material adverse impact on Crescent Point's liquidity position, including its ability to pay obligations as they come due.

***We have been historically reliant on external sources of capital, which may dilute Shareholders' ownership interests.***

There may be future dilution to our Shareholders. One of our objectives is to continually add to our reserves through acquisitions and through development. Since we pay a dividend, our success in growth from acquisitions and development may, in part, depend on our ability to raise capital from time to time by selling additional Common Shares. Shareholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common Shares issued to acquire those assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to effect acquisitions.

**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.***

Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons 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 reserve 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 these 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 trailing 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-month for each month within the 12-month period to the end of the reporting period, and uninflated (constant) costs be utilized. The SEC permits, but does not require, the disclosure of reserves based on forecast prices and costs.

Reserve information contained herein include estimates of Proved and Proved plus Probable reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only Proved reserves. The SEC permits, but does not require, the inclusion of estimates of Probable reserves in filings made with it by United States oil and gas companies. The SEC definitions of Proved reserves and Probable reserves are different than those in NI 51-101. As a consequence of the foregoing, our reserve estimates and production volumes in this AIF may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

***Additional taxation applicable to non-residents.***

The Tax Act imposes a withholding tax at the rate of 25% on dividends paid by us to Shareholders who are non-residents of Canada, unless the rate is reduced under the provisions of a tax treaty between Canada and the non-resident Shareholder's jurisdiction of residence. These withholding tax rates may change from time to time. Where the non-resident Shareholder is a United States resident entitled to benefits under the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividend, the rate of Canadian withholding tax applicable to dividends is generally reduced to 15%. Shareholders who are non-residents of Canada are encouraged to consult with their tax advisors for more information concerning additional taxation that may be applicable to them.

***Foreign exchange risk for non-resident Shareholders.***

Our dividends are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to their home currency.

## **DIVIDENDS AND SHARE REPURCHASES**

The Corporation has established a dividend policy of paying regular dividends to Shareholders. An objective of the Corporation's dividend policy is to provide Shareholders with relatively stable and predictable dividends. An additional objective is to retain a portion of cash flow to fund ongoing development and optimization projects designed to enhance the sustainability of the Corporation's cash flow. Commencing in 2019, the Corporation moved to a quarterly dividend, paid on the first business day of each quarter. Dividends are paid to Shareholders of record on the 15<sup>th</sup> day of the month prior to the payment date.

The amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including the price of oil and gas, the prevailing economic and competitive environment, results of operations, fluctuations in working capital, the taxability of Crescent Point, Crescent Point's ability to raise capital, the amount of capital expenditures and other conditions existing from time to time. There can be no guarantee that Crescent Point will maintain its dividend policy.

Although the Corporation strives to provide Shareholders with stable and predictable cash flows, the percentage of cash flow from operations paid to Shareholders may vary according to a number of factors, including, fluctuations in resources prices, exchange rates and production rates, reserves growth, the size of development drilling programs and the portion thereof funded from cash flow and the overall level of debt of the Corporation.

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

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

		<u>Dividend per Common Share (\$)</u>	
January 2017	–	December 2018	0.03 per month
January 2019	–	December 2019	0.01 per quarter

### **Normal Course Issuer Bid**

On January 25, 2019, Crescent Point commenced a normal course issuer bid (the "**NCIB**") to purchase, for cancellation, up to 38,424,678 Common Shares, representing 7% of the Corporation's public float as at January 14, 2019. The NCIB expired on January 24, 2020. The actual number of Common Shares purchased under the NCIB was 26,238,600. The objective of the NCIB is to return capital to Shareholders in a way that is accretive to both Shareholders and the Corporation. Purchases of Common Shares under the NCIB may be made through the facilities of the TSX or the NYSE, alternative trading systems by means of open market transactions, or by such other means as may be permitted by the TSX and applicable securities laws.

**MARKET FOR SECURITIES**

The outstanding Common Shares are traded on the TSX and the NYSE under the trading symbol "CPG". The following tables set forth the price range and trading volume of the Common Shares as reported by the TSX and NYSE for the periods indicated.

<b>TSX</b>	<b>High (\$)</b>	<b>Low (\$)</b>	<b>Volume (000's)</b>
<u>2019</u>			
January	4.70	3.82	96,001
February	4.44	3.24	85,821
March	4.76	3.67	129,654
April	5.98	4.02	156,106
May	5.56	4.49	102,381
June	4.60	3.85	74,502
July	4.53	3.85	76,256
August	4.35	3.69	64,784
September	6.30	4.19	109,581
October	5.74	4.68	64,007
November	5.47	4.60	75,672
December	5.94	4.44	78,052
<u>2020</u>			
January	6.30	4.27	81,104
February	4.49	3.30	73,870
<b>NYSE</b>	<b>High (US\$)</b>	<b>Low (US\$)</b>	<b>Volume (000's)</b>
<u>2019</u>			
January	3.55	2.88	43,620
February	3.39	2.44	53,888
March	3.55	2.74	70,887
April	4.45	3.02	71,583
May	4.16	3.32	67,813
June	3.45	2.89	54,733
July	3.47	2.95	46,762
August	3.27	2.77	45,139
September	4.76	3.13	77,709
October	4.32	3.55	60,168
November	4.13	3.49	49,413
December	4.58	3.34	55,001
<u>2020</u>			
January	4.84	3.23	43,237
February	3.38	2.47	49,812



## **CONFLICTS OF INTEREST**

Circumstances may arise where members of the Board of Directors or officers of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such Board members or officers will be provided to the Corporation. In accordance with the ABCA, a director or officer who is a party to a material contract or proposed material contract with the Corporation or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Corporation shall disclose to the Corporation the nature and extent of the director's or officer's interest. In addition, a director shall not vote on any resolution to approve a contract of the nature described except in limited circumstances. Management of the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation or a subsidiary of the Corporation and a director or officer of the Corporation or any other subsidiary of the Corporation.

## **LEGAL PROCEEDINGS**

There are no outstanding legal proceedings material to the Corporation to which we are a party or in respect of which any of our properties are subject, nor are any such proceedings known to be contemplated.

## **AUDIT COMMITTEE**

### **General**

The Corporation has established an Audit Committee (the "**Audit Committee**") comprised of four members: Laura A. Cillis (Chair), James E. Craddock, Ted Goldthorpe and Mike Jackson, each of whom is considered "independent" and "financially literate" within the meaning of Multilateral Instrument 52-110 – Audit Committees.

### **Mandate of the Audit Committee**

The mandate of the Audit Committee is to assist the Board of Directors in its oversight of the integrity of the financial and related information of the Corporation and its subsidiaries and related entities, including the consolidated financial statements, internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements. In doing so, the Audit Committee oversees the audit efforts of our external auditors and, in that regard, is empowered to take such actions as it may deem necessary to satisfy itself that our external auditors are independent of us. It is the objective of the Audit Committee to have direct, open and frank communications throughout the year with management, other Committee chairmen, the external auditors, and other key committee advisors or the Corporation's staff members, as applicable.

The Audit Committee's function is oversight. Management of the Corporation is responsible for the preparation, presentation and integrity of the consolidated financial statements of the Corporation. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies as well as internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations.

While the Audit Committee has the responsibilities and powers set forth above, it is not the duty of the Audit Committee to plan or conduct audits or to determine whether the consolidated financial statements of the Corporation are complete and accurate and are in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors, on whom the members of the Committee are entitled to rely upon in good faith.

The Audit Committee Terms of Reference are attached hereto as Appendix A.

## Relevant Education and Experience of Audit Committee Members

The following is a brief summary of the education or experience of each member of the Audit Committee that is relevant to the performance of his or her responsibilities as a member of the Audit Committee, including any education or experience that has provided the member with an understanding of the accounting principles used by us to prepare our annual and interim consolidated financial statements.

Name of Audit Committee Member	Relevant Education and Experience
Laura A. Cillis	<p>Ms. Laura A. Cillis has 25 years of experience working in publicly traded, primarily international, organizations and has a broad range of leadership, corporate governance and financial experience. Ms. Cillis is currently a Director and member of the Audit Committee of Shawcor Ltd. and she is a Director of Western Forest Products Inc. and a member of both its Audit Committee and its Nominating &amp; Corporate Governance Committee.</p> <p>Ms. Cillis was previously a member of and held a variety of roles on the Board of Directors for Solium Capital Inc., Enbridge Income Fund Holdings Inc. and the Enbridge Income Fund group of companies. She previously served as Senior Vice President, Finance and Chief Financial Officer for Calfrac Well Services Ltd. from November 2008 to June 2013. Prior thereto, she was the Chief Financial Officer of Canadian Energy Services L.P. since January 2006.</p> <p>Ms. Cillis is a Chartered Professional Accountant, holds the ICD.D designation granted by the Institute of Corporate Directors and is a member of Financial Executives International. Ms. Cillis earned her Bachelor of Commerce degree from the University of Alberta.</p>
James E. Craddock	<p>Mr. James E. Craddock is a seasoned upstream executive who possesses broad-based technical knowledge with over 30 years of experience. He has served on Noble Energy Inc.'s Board of Directors since its merger with Rosetta Resources Inc. in 2015 and served as the Chairman, Chief Executive Officer and President of Rosetta from 2013 to 2015. He is currently a member of Noble's Compensation and Corporate Governance and Nominating committees and is Chair of the Safety, Sustainability and Corporate Responsibility Committee. Previously, he was the Executive Director and Chief Operating Officer for BPI Industries Inc. and held several positions of increasing responsibility over a 20-year career at Burlington Resources Inc.</p> <p>Mr. Craddock holds a Bachelor of Science in Mechanical Engineering from Texas A&amp;M University and previously served on the Boards of Templar Energy and the Texas Railroad Commission.</p>
Ted Goldthorpe	<p>Mr. Ted Goldthorpe is a financial professional who is currently serving as Managing Partner in charge of Global Credit Business for BC Partners since February 2017. Prior thereto, he was the President of Apollo Investment Corporation, Chief Investment Officer of Apollo Investment Management, and Senior Portfolio Manager, U.S. Opportunistic Credit from April 2012 to August 2016. Previously, Mr. Goldthorpe was employed by Goldman Sachs &amp; Co., where he held a variety of positions since joining the firm in 1999. Mr. Goldthorpe joined the Board of Crescent Point in May 2017.</p> <p>Mr. Goldthorpe received a B.A. in Commerce from Queen's University and is a frequent guest lecturer at leading universities across North America. Mr. Goldthorpe currently serves on the Global Advisory Board for the Queen's School of Business and serves on the board of directors for Her Justice and Capitalize for Kids.</p>
Mike Jackson	<p>Mr. Mike Jackson worked in the banking sector from 1984 until his retirement in 2016. From 1997 to 2016 he was Managing Director in Scotiabank's Corporate &amp; Investment Banking group focused on the oil &amp; gas industry, including ten years heading the group. For the period 2006-2016, Mr. Jackson served as Financial Advisor to Boards/companies on M&amp;A transactions aggregating over \$28 billion. Mr. Jackson joined the Board of Crescent Point in November 2016.</p> <p>Mr. Jackson holds a Bachelor of Science degree and a Master of Business Administration, both from Dalhousie University and the ICD.D designation granted by the Institute of Corporate Directors. Additionally, Mr. Jackson completed the Executive Management Program at Queen's University.</p>

## External Auditor Services Fees

For services provided to the Corporation and its subsidiaries the years ended December 31, 2019 and 2018 PricewaterhouseCoopers LLP billed approximately \$1,290,025 and \$1,746,288, respectively, as detailed below:

	Year ended December 31	
	2019	2018
PricewaterhouseCoopers		
Audit fees	\$ 1,151,551	\$ 1,529,983
Audit-related fees	\$ 25,382	\$ 216,305
Tax fees	—	—
All other fees	\$ 113,093	—
<b>Total</b>	<b>\$ 1,290,025</b>	<b>\$ 1,746,288</b>

The Chair of the Audit Committee has the authority to pre-approve non-audit services which may be required from time to time.

Audit Fees were paid, or are payable, for professional services rendered by the auditors for the audit of the annual financial statements and reviews of the quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements. Audit-related fees consist of the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as Audit fees. The services in this category include participation fees levied by the Canadian Public Accountability Board. All Other Fees were for products or services provided by Crescent Point's auditors other than those described as Audit Fees and Audit-Related Fees. All services described beside the captions "Audit Fees", "Audit-Related Fees", and "All Other Fees" were approved by the Audit Committee in compliance with paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X under the U.S. Securities and Exchange Act of 1934, as amended (the "**Exchange Act**"). None of the fees described above were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Regulation S-X under the Exchange Act.

#### **Audit Committee Oversight**

At no time since the commencement of our most recently completed financial year, has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the Board of Directors.

#### **TRANSFER AGENT AND REGISTRARS**

The transfer agent and registrar for our Common Shares is Computershare Trust Company of Canada in Calgary, Alberta.

#### **AUDITOR**

Our auditor is PricewaterhouseCoopers LLP, Chartered Professional Accountants, 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3.

### **MATERIAL CONTRACTS**

Set out below is the only agreement that may be considered material to us:

Premium Dividend and Dividend Reinvestment Plan. See "*Additional Information Respecting Crescent Point – Premium Dividend and Dividend Reinvestment Plan*".

### **INTERESTS OF EXPERTS**

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated March 4, 2020 in respect of the Corporation's consolidated financial statements as at December 31, 2019 and December 31, 2018 and the Corporation's internal control over financial reporting as at December 31, 2019. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules of the U.S. Securities and Exchange Commission.

Reserve estimates contained in this AIF are derived from reserve reports prepared by GLJ and Sproule. As of the date hereof, GLJ, as a group and Sproule, as a group, do not beneficially own, directly or indirectly, any Common Shares.

### **ADDITIONAL INFORMATION**

Additional financial information is available on SEDAR at [www.sedar.com](http://www.sedar.com), on EDGAR at [www.sec.gov/edgar.shtml](http://www.sec.gov/edgar.shtml) and on our website at [www.crescentpointenergy.com](http://www.crescentpointenergy.com).

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in our information circular in respect of the annual meeting of Shareholders held on June 14, 2019, which is available on SEDAR. Additional financial information is provided in our comparative consolidated financial statements and management's discussion and analysis for our most recently completed financial year ended December 31, 2019.

For additional copies of this AIF please contact:

Crescent Point Energy Corp.  
2000, 585 – 8th Avenue, S.W.  
Calgary, Alberta  
T2P 1G1

Attention: Investor Relations



## APPENDIX A

### AUDIT COMMITTEE TERMS OF REFERENCE

#### Corporate Policies & Procedures

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#### I. The Board of Directors' Mandate for the Audit Committee

##### 1. General

The Board of Directors (the "Board") has responsibility for the stewardship of Crescent Point Corp. ("Crescent Point") and its subsidiaries or related entities (collectively referred to herein as the "Corporation"). To discharge that responsibility, the Board is obligated by the *Business Corporations Act (Alberta)* to supervise the management of the business and affairs of the Corporation. The Board's supervisory function involves Board oversight or monitoring of all significant aspects of the management of the Corporation's business and affairs.

Public financial reporting and disclosure by the Corporation are fundamental to the Corporation's business and affairs and to its status as a publicly listed enterprise. The objective of the Board's monitoring of the Corporation's financial reporting and disclosure is to gain reasonable assurance of the following (including, where advisable in the achievement of this objective, through appropriate consultation with senior management and the Corporation's external auditors):

- (a) that the Corporation complies with all applicable laws, regulations, rules, policies and other requirements of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;
- (b) that the accounting principles, significant judgments and disclosures which underlie or are incorporated in the Corporation's consolidated financial statements are the most appropriate in the prevailing circumstances;
- (c) that the Corporation's quarterly and annual consolidated financial statements and Annual Information Forms ("AIF") are accurate within a reasonable level of materiality and present fairly the Corporation's financial position and performance in accordance with the recognition and measurement principles of International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"); and
- (d) that appropriate information concerning the financial position and performance of the Corporation is disseminated to the public in a timely manner in accordance with corporate and securities law and with stock exchange regulations.

The Board is of the view that monitoring of the Corporation's financial reporting and disclosure policies and procedures cannot be reliably met unless the following activities (the "Fundamental Activities") are conducted effectively:

- (i) the Corporation's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Corporation's financial transactions and properly certified;
- (ii) the internal financial controls are regularly assessed for effectiveness and efficiency;

- (iii) the Corporation's quarterly and annual consolidated financial statements are properly prepared by management to comply with IFRS; and
- (iv) the Corporation's quarterly and annual consolidated financial statements and Management Discussion and Analysis ("MD&A") are reported on by an external auditor appointed by the shareholders of the Corporation.

To assist the Board in its monitoring of the Corporation's financial reporting and disclosure and to conform to applicable corporate and securities law, the Board has established the Audit Committee (the "Committee") of the Board.

## **2. Role of the Committee**

The role of the Committee is to assist the Board in its oversight of the integrity of the financial and related information of the Corporation, including its consolidated financial statements, the internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements and to review the independence, qualifications and performance of the external auditor of the Corporation. Management is responsible for establishing and maintaining those controls, procedures and processes and the Committee is appointed by the Board to review and monitor them.

The Committee has the authority to conduct any review or investigation appropriate to fulfilling its responsibilities. The Committee shall have unrestricted access to personnel and information, and any resources necessary to carry out its responsibility. In this regard, the Committee may direct internal audit personnel to particular areas of examination.

## **3. Composition of Committee**

- (a) The Committee shall be appointed annually by the Board and consist of at least three members from among the directors of the Corporation.
- (b) All members of the committee (the "Members") must be "independent" under Multilateral Instrument 52-110. All Members must be "financially literate" (i.e., have the ability to read and understand a balance sheet, an income statement and a cash flow statement). In particular, at least one member shall have, through
  - (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions;
  - (ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions;
  - (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or
  - (iv) other relevant experience:
    - An understanding of accounting principles and financial statements;
    - The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;
    - Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising one or more persons engaged in such activities;
    - An understanding of internal controls and procedures for financial reporting; and
    - An understanding of audit committee functions.
- (c) Committee members may not, other than in their respective capacities as members of the Committee, the Board or any other committee of the Board, accept directly or indirectly any consulting, advisory or other compensatory fee from the Corporation or any subsidiary of the Corporation, or be an "affiliated person" (as

such term is defined in the United States Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the rules, if any, adopted by the U.S. Securities and Exchange Commission ("SEC") thereunder) of the Corporation or any subsidiary of the Corporation. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation that are not contingent on continued service should be the only compensation a Committee member receives from the Corporation.

- (d) At least one member shall have experience in the oil and gas industry.
- (e) Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.
- (f) The Board shall designate the Chair of the Committee.
- (g) The Chair of the Board shall be an exofficio member of the Committee and shall be entitled to attend all meetings of the Committee.
- (h) In the event of a vacancy arising in the Committee or a loss of independence of any Member, the Committee will fill the vacancy within six weeks or by the following annual shareholders' meeting if sooner.

#### **4. Reliance on Experts**

In contributing to the Committee's discharging of its duties under this mandate, each Member of the Committee shall be entitled to rely in good faith upon:

- (a) consolidated financial statements of the Corporation represented to him by an officer of the Corporation or in a written report of the external auditors to present fairly the financial position of the Corporation in accordance with IFRS; and
- (b) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

#### **5. Limitations on the Committee's Duties**

In contributing to the Committee's discharging of its duties under Terms of Reference, each Member shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in these Terms of Reference is intended, or may be construed, to impose on any Member a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the objectives of the Corporation's financial reporting are being met and to enable the Committee to report thereon to the Board.

## **II. Audit Committee Terms of Reference**

These Terms of Reference outline how the Committee will satisfy the requirements set forth by the Board in its mandate.

### **1. Operating Principles**

The Committee shall fulfill its responsibilities within the context of the following principles.



### *Committee Values*

The Committee expects the management of the Corporation to operate in compliance with corporate policies; reflecting laws and regulations governing the Corporation; and to maintain strong financial reporting and control processes.

### *Communications*

The Committee and its Members expect to have direct, open and frank communications throughout the year with management, other Committee Chairmen, the external auditors, and other key Committee advisors or Company staff members as applicable.

### *Delegation*

The Committee may delegate from time to time to any person or committee of persons any of the Committee's responsibilities that may be lawfully delegated.

### *Annual Audit Committee Plan*

The Committee, in consultation with management and the external auditors, shall develop an annual Audit Committee plan responsive to the Committee's responsibilities as set out in these Terms of Reference. In addition, the Committee, in consultation with management and the external auditors, shall develop and participate in a process for review of important financial topics that have the potential to impact the Corporation's financial disclosure.

The plan will be focused primarily on the annual and interim consolidated financial statements and MD&A of the Corporation; however, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the Committee's Terms of Reference.

### *Committee Expectations and Information Needs*

The Committee shall communicate its expectations to management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at a reasonable time in advance of meeting dates.

### *Access to Independent Advisors*

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditors, at the expense of the Corporation, retain one or more persons, firms or corporations having special expertise.

### *Reporting to the Board, Shareholders and Others*

The Committee, through its Chair, shall report after each Committee meeting to the Board at the Board's next regular meeting. In addition, the Committee shall prepare a report to shareholders or others, concerning the Committee's activities in the discharge of its responsibilities, when and as required by applicable laws, rules, policies or regulations.

### *Evaluation*

The Committee will conduct and present to the Board an annual evaluation of the performance of the Committee and the adequacy of these Terms of Reference and recommend any proposed changes to the Board for approval.

### *Access to the Committee*

Representatives of the Auditor and management of the Corporation shall have access to the Committee each in absence of the other.

### *The External Auditors*

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditors shall be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues, either specific to the Corporation or to the financial reporting environment in general, to the Committee.

### *No Alteration*

No alteration to the roles and responsibilities of the Committee shall be effective without the approval of the Board.

## **2. Operating Procedures**

### *Meetings*

The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair, upon the request of two (2) Members or at the request of the external auditors.

### *Quorum*

A quorum shall be a majority of the Members.

### *Notice of Meeting*

Notice of the time and place of every meeting shall be given in writing by any means of transmitted or recorded communication, including facsimile, email or other electronic means that produces a written copy, to each Member of the Committee at least 24 hours prior to the time fixed for such meeting; provided however, that a Member may in any manner waive a notice of the meeting. Attendance of a Member at a meeting constitutes waiver of notice of the meeting, except where a Member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.

### *Meeting Agenda*

Committee meeting agendas shall be the responsibility of the Chair of the Committee in consultation with other Members, senior management and the external auditors.

### *Procedure, Records and Reporting*

Subject to any statute or the articles and by-laws of the Corporation, the Committee shall fix its own procedures at meetings, keep records of its proceedings and report to the Board when the Committee may deem appropriate (but not later than the next regularly scheduled meeting of the Board).

### *In Camera Meetings*

At the discretion of the Committee, the Members shall meet in private session with the external auditors and with management only.

### *Referral to the Board*

Any matter the Committee does not unanimously approve will be referred to the Board for consideration.

### *Secretary*

Unless the Committee otherwise specifies, the Corporate Secretary (or his or her depute) of the Corporation shall act as Secretary of all meetings of the Committee.

### *Acting Chair*

In the absence of the Chair of the Committee, the Members shall appoint an acting Chair.

### *Minutes*

A copy of the minutes of each meeting of the Committee shall be provided to each Member and to each director of the Corporation in a timely fashion.

### *Attendance at Meetings*

The Chief Executive Officer, the Chief Financial Officer and the internal audit and tax staff are expected to be available to attend the Committee's meetings or portions thereof, and the Chief Executive Officer is entitled to attend all meetings of the Committee.

The Committee may, by specific invitation, have other resource persons in attendance.

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Committee Chair or by a majority of the members of the Committee.

## **3. Specific Responsibilities and Duties**

To fulfill its responsibilities and duties, the Committee shall:

### *Financial Information and Reporting*

- (a) Review, prior to public release, the Corporation's annual and quarterly consolidated financial statements with management and the external auditors to gain reasonable assurance that the statements are accurate within reasonable levels of materiality, complete, represent fairly the Corporation's financial position and performance and are in accordance with IFRS and report thereon to the Board before such consolidated financial statements are approved by the Board;
- (b) Receive from the external auditors reports on their review of the annual and quarterly consolidated financial statements;
- (c) Receive from management a copy of the representation letter provided to the external auditors and receive from management any additional representations required by the Committee;
- (d) Review, prior to public release, all news releases issued by the Corporation with respect to the Corporation's annual and quarterly consolidated financial statements; and
- (e) Review, prior to public release, prospectuses, material change disclosures of a financial nature, management discussion and analysis, AIF and similar disclosure documents to be issued by the Corporation.

### *Accounting Policies*

- (a) Review with management and the external auditors the appropriateness of the Corporation's accounting policies, disclosures, reserves, key estimates and judgments, including changes or variations thereto;
- (b) Obtain reasonable assurance that the accounting policies, disclosures, reserves, key estimates and judgments are in compliance with IFRS from management and external auditors and report thereon to the Board;

- (c) Review with management and the external auditors the degree of conservatism of the Corporation's underlying accounting policies, key estimates and judgments and reserves along with quality of financial reporting; and
- (d) Participate, if requested, in the resolution of disagreements between management and the external auditors.

*Risk and Uncertainty*

- (a) Acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Corporation, determine the Corporation's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:
  - (i) reviewing with management the Corporation's tolerance for financial risks;
  - (ii) reviewing with management its assessment of the significant financial risks facing the Corporation;
  - (iii) reviewing with management the Corporation's policies and any proposed changes thereto for managing those significant financial risks; and
  - (iv) reviewing with management its plans, processes and programs to manage and control such risks.
- (b) Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;
- (c) Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;
- (d) Review the adequacy of insurance coverages maintained by the Corporation; and
- (e) Review regularly with management, the external auditors and the Corporation's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these matters have been disclosed in the consolidated financial statements.

*Financial Controls and Control Deviations*

- (a) Review the plans of the external auditors to gain reasonable assurance that the evaluation and testing of internal financial controls is comprehensive, coordinated and cost effective;
- (b) Receive regular reports from management and the external auditors on all significant deviations from IFRS or other Company internal control processes or indications which may suggest fraud and the corrective activity undertaken in respect thereto; and
- (c) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Board or the Committee concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgment, through existing reporting structures in the Corporation.

*Compliance with Laws and Regulations*

- (a) Receive and review regular reports from management and others (e.g. external auditors) with respect to the Corporation's compliance with laws and regulations having a material impact on the consolidated financial statements including:
  - (i) tax and financial reporting laws and regulations;

- (ii) legal withholding requirements; and
  - (iii) other laws and regulations which expose directors to liability; and
- (b) Review the filing status of the Corporation's tax returns and those of its subsidiaries or related entities.

*Relationship and External Auditors*

- (a) Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Corporation. The external auditors shall report directly to the Committee;
- (b) Recommend to the Board the nomination of the external auditors;
- (c) Pre approve and recommend to the Board the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter. The Chair of the Committee hereby has the authority to pre approve non audit services which may be required from time to time;
- (d) Review the performance of the external auditors annually or more frequently as required;
- (e) Receive annually from the external auditors an acknowledgement in writing that the shareholders, as represented by the Board and the Committee, are their primary client;
- (f) Receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non audit services by the Corporation;
- (g) Review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ;
- (h) Meet with the external auditors at least once a year in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee;
- (i) Establish effective communication processes with management and the Corporation's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee; and
- (j) Establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgment of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee of any disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

*Relationship with Internal Auditor*

- (a) Review the internal audit staff functions, including:
  - (i) the purpose, authority and organizational reporting lines;
  - (ii) the annual audit plan, budget and staffing; and
  - (iii) the appointment and compensation of any person with the responsibility for the Internal Audit; and

- (b) Review, with the Chief Financial Officer, controller or others, as appropriate, the Corporation's internal system of audit controls and the results of internal audits.

#### *Other Responsibilities and Procedures*

- (a) After consultation with the Chief Financial Officer and the external auditors, gain reasonable assurance, at least annually, of the quality and sufficiency of the Corporation's accounting and financial personnel and other resources;
- (b) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;
- (c) Determine the appropriate funding for payment by the Corporation (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, (ii) of compensation to any advisors employed by the Committee, and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties; and
- (d) Perform such other functions as may from time to time be assigned to the Committee by the Board.

### **III. Hiring Guidelines for Independent Auditor Employees**

#### **1. Guidelines**

The Committee has adopted the following guidelines regarding the hiring of any partner, employee, reviewing tax professional or other person providing audit assurance to the external auditor of the Corporation on any aspect of its certification of the Corporation's consolidated financial statements:

- (a) No senior member of the audit team that is auditing a business of the Corporation can be hired into that business or into a position to which that business reports for a period of two years after the audit; and
- (b) No former partner or employee of the external auditor may be made an officer of the Corporation or any of its subsidiaries for two years following association with the external auditor:
  - (i) The Chief Executive Officer must approve all office hires from the external auditor; and
  - (ii) The Chief Financial Officer must report annually to the Committee on any hires within these guidelines during the preceding year.

#### **2. Audit Partner Rotation**

The Committee will ensure that the head audit partner assigned by the external auditor to the Corporation, as well as the audit partner charged with reviewing the audit of the Corporation, are changed at least every five years.

#### **3. Process for Handling Complaints about Accounting Matters**

The Committee will establish the following procedures for the receipt and treatment of any complaint received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls or auditing matters and create a summary of any significant investigations regarding such matters:

- (a) The Corporation will publish on its website special mail and e-mail addresses and a toll-free telephone number for receiving complaints regarding accounting, internal accounting controls or auditing matters;
- (b) Copies of complaints received will be sent to the Members of the Committee;

- (c) All complaints will be investigated by the Corporation's finance and legal staffs in the normal manner, except as otherwise directed by the Committee. The Committee may request that outside advisors be retained to investigate any complaint; and
- (d) The status of each complaint will be reported on a quarterly basis to the Committee and, if the Committee so directs, to the full board.



## APPENDIX B

### RESERVES COMMITTEE TERMS OF REFERENCE

#### Corporate Policies & Procedures

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#### 1. Reserves Committee Purpose

The Reserves Committee (the "Committee") is appointed by the Board of Directors of Crescent Point Energy Corp. (the "Board") to assist the Board in fulfilling its responsibility for the stewardship of Crescent Point Energy Corp. ("Crescent Point") and its subsidiaries or related entities (collectively referred to herein as the "Corporation"). The Committee's primary duties and responsibilities are to assume responsibility for assisting the Board in respect of the annual independent review of Crescent Point's petroleum and natural gas reserves and reporting to the Board in respect thereof.

#### 2. Reserves Committee Responsibilities and Duties

The overall duties and responsibilities of the Committee shall be as follows:

- (a) in conjunction with the Corporation's senior engineering management, meet with the independent evaluating engineers being considered for appointment to review their qualifications and independence to ensure the independent evaluating engineers being considered for appointment are technically qualified and competent, are independent of management and to establish the terms of their engagement;
- (b) after consultation with the Corporation's senior engineering management, recommend to the Board the appointment of the independent evaluating engineers to assist the Corporation in the annual review of its petroleum and natural gas reserves;
- (c) in consultation with the Corporation's senior engineering management determine the scope of the annual review of the petroleum and natural gas reserves by the independent evaluating engineers, having regard to regulatory reporting requirements;
- (d) review, with reasonable frequency, the Corporation's procedures for providing petroleum and natural gas reserves information to the qualified independent evaluating engineers who report on reserves data for the purposes of National Instrument 51 - 101, and the information used by the independent evaluating engineers to enable the independent evaluating engineers to provide a report that will meet regulatory reporting requirements;
- (e) in consultation with the Corporation's senior engineering management and the independent evaluating engineers:
  - determine whether any restrictions affect the ability of the independent evaluating engineers to report on reserve data without reservations; and
  - review the reserves data and the report of the independent evaluating engineers.



- (f) ensure the disclosure to the public on the Corporation's petroleum and natural gas reserves is in compliance with regulatory requirements and make appropriate changes, reports or recommendations to the Board with respect to the procedures for such disclosure;
- (g) review any proposal to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;
- (h) meet on an annual basis with the Corporation's senior engineering management and/or the independent evaluating engineers of the Corporation to review and consider the evaluation of the Corporation's petroleum and natural gas reserves;
- (i) meet separately with the independent evaluating engineers and/or senior engineering management when the Committee deems it desirable and advise the Board on the results of such meeting;
- (j) coordinate meetings with the Audit Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation's evaluation of petroleum and natural gas reserves;
- (k) review annually the Committee charter and recommend any changes to the Board; and
- (l) to maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

### **3. Reserves Committee Members' Duties in Addition to Those of Director**

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board.

### **4. Reporting**

The Committee shall report to the Board. The Committee shall provide the Board with a summary of all meetings held at a regularly scheduled meeting of the Board held following any Committee meetings.

### **5. Composition**

The Committee will be comprised of at least three members as determined by the Board. The Committee members shall satisfy the independence and experience requirements of applicable securities laws, rules, or guidelines, any applicable stock exchange requirements or guidelines and any other applicable regulatory rules. In particular, a majority of the members of the Committee shall be free from any relationship which could reasonably be expected to materially interfere with the member's independent judgment. Determinations as to whether a particular director satisfies the requirements for membership on the Committee shall be made by the full Board and shall be reviewed at least annually.

The Chair of the Board shall be an exofficio member of the Committee and shall be entitled to attend all meetings of the Committee.

Committee members will include only duly-elected directors. Members of the Committee shall be appointed from time to time by the Board. Each member shall serve until his or her successor is appointed, unless he or she resigns or is removed by the Board or he or she otherwise ceases to be a director of the Corporation. If a member of the Committee ceases to be independent for reasons outside that member's reasonable control, the member shall immediately notify the Chair of the Board as to this fact and shall resign his or her position as a member of the Committee on the earliest of (i) the appointment of his or her successor; (ii) the next annual meeting of shareholders of the Corporation; and (iii) the date that is six months from the occurrence of the event which caused the member to not be independent. The Board shall fill any vacancy if the membership of the Committee is less than three directors.

## **6. Chair**

The Board shall appoint the Chair of the Committee or, if it does not do so, the members of the Committee may elect a Chair by a vote of a majority of the full Committee membership. The Chair shall be an independent director. If the Chair of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen to preside by a majority of the members of the Committee present at such meeting.

## **7. Secretary**

The Corporate Secretary of the Corporation or such other person as the Corporate Secretary of the Corporation shall designate from time to time, shall be the Secretary of the Committee and shall keep minutes of the meetings of the Committee.

## **8. Operation of Committee Meetings**

The Committee shall have access to such officers and employees of the Corporation and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities. The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any such counsel and advisors, such engagement to be for the Corporation's sole account and expense.

Committee meetings may, by agreement of the Chair of the Committee, be held in person, by means of telephone or by a combination of any of the foregoing.

Meetings of the Committee shall be conducted as follows:

- (a) The Committee shall meet at least two times annually at such times and at such locations as the Chair of the Committee shall determine. Any two members of the Committee may also request a meeting of the Committee.
- (b) The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other.
- (c) The Chair shall, in consultation with management, establish the agenda for the meetings and instruct management to ensure that properly prepared agenda materials are circulated to the Committee with sufficient time for study prior to the meeting.
- (d) Every question at a Committee meeting shall be decided by a majority of the votes cast.
- (e) The Chief Executive Officer is expected to be available to attend the Committee's meetings or portions thereof. The Committee may, by specific invitation, have other resource persons in attendance. The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee, provided that the Chief Executive Officer of the Corporation is entitled to attend all meetings of the Committee. Directors, who are not members of the Committee, may attend Committee meetings on an ad hoc basis upon prior consultation and approval by the Committee Chair or by a majority of the members of the Committee.
- (f) The Committee may delegate from time to time to any person or committee of persons any of the Committee's responsibilities that lawfully may be delegated.
- (g) Minutes of each Committee meeting should be succinct yet comprehensive in describing substantive issues discussed by the Committee. However, they should clearly identify those items of responsibilities scheduled by the Committee for the meeting that have been discharged by the Committee and those items of

responsibilities that are outstanding. Minutes of the Committee meeting shall be sent firstly to the Chair and next to all Committee members.

**9. Notice of Meeting**

Notice of the time and place of each meeting may be given orally, or by electronic means, or in writing, or by facsimile to each member of the Committee at least 24 hours prior to the time fixed for such meeting.

A member may in any manner waive notice of the meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

**10. Miscellaneous**

The Committee, with unanimity, may engage outside resources if deemed advisable. Lack of unanimity requires that the matter be referred to the Nominating and Corporate Governance Committee.

## Appendix C

### FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Crescent Point Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook, as amended from time to time, (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	December 31, 2019	Canada	—	2,015,860	—	2,015,860

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 14, 2020

#### ORIGINALLY SIGNED BY

**Todd J. Ikeda, P. Eng.**  
**Vice President**

**FORM 51-101F2  
REPORT ON RESERVES DATA  
BY  
INDEPENDENT QUALIFIED RESERVES  
EVALUATOR OR AUDITOR**

To the board of directors of Crescent Point Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook, as amended from time to time, (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - Cdn. \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	December 31, 2019	U.S.A.	—	1,366,833	—	1,366,833

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 14, 2020

**ORIGINALLY SIGNED BY**

**Todd J. Ikeda, P. Eng**  
**Vice President**

**FORM 51-101F2  
REPORT ON RESERVES DATA  
BY  
INDEPENDENT QUALIFIED RESERVES  
EVALUATOR OR AUDITOR**

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

1. We have evaluated the Company's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook, as amended from time to time, (the "**COGE Handbook**"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - Cdn. \$M)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	December 31, 2019	Canada				
<b>Total</b>			Nil	8,404,263	Nil	8,404,263

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of Certain Saskatchewan P&NG Reserves of Crescent Point Energy Corp. (As of December 31, 2019)".
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta

January 21, 2020

**ORIGINALLY SIGNED BY**

**Douglas O. McNichol, P.Eng.  
Senior Manager, Engineering**

**Vincent K. Hui, P.Eng.  
Senior Petroleum Engineer**

**Shishir Shivhare, P.Eng.  
Petroleum Engineer**

**Nora T. Stewart, P.Eng.  
Senior Vice President, Responsible Member Engineering**

**Ian Kirkland, P.Geol.  
Senior Geologist, Responsible Member Geoscience**

## Appendix D

### REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

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

GLJ Petroleum Consultants and Sproule Associates Limited, each an independent qualified reserves evaluators have evaluated the Corporation's reserves data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has:

- (a) reviewed the Corporation'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 evaluators.

The Reserves Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the 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.

*"Craig Bryksa"*

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CRAIG BRYKSA  
President and Chief Executive Officer

*"Ryan Gritzfeldt"*

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RYAN GRITZFELDT  
Chief Operating Officer

*"Francois Langlois"*

---

FRANCOIS LANGLOIS  
Director

*"Barbara Munroe"*

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BARBARA MUNROE  
Chair of the Board

March 4, 2020