CRESCENT POINT ENERGY CORP.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2022

Dated March 1, 2023

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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 AIF (as defined herein) 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 and return capital to shareholders;
- return of capital framework that targets the return of up to 50% of the Corporation's discretionary excess cash flow;
- 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, including focus areas;
- 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 enhanced oil recovery and waterflood programs;
- the possible impacts of curtailment on Crescent Point;

- the impacts of the Redwater decision and other legal decisions;
- 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, including special dividends, and the repurchase of Common Shares (as defined herein) by Crescent Point, including pursuant to its normal course issuer bid;
- supply and demand for oil and natural gas;
- the actions of OPEC+;
- expectations of legal and regulatory changes and implementations and change in governmental and 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;
- stock option grants;
- the impacts of the war in Ukraine;
- the impacts of COVID-19; 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, 2022, 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, 2022, under the headings "Overview", "Development Capital Expenditures", "Commodity Derivatives", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Guidance".

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 impacts of the war in Ukraine; the actions of OPEC+; 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; 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; the impacts of COVID-19; 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; inflation; 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.

Netback received is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback received excludes realized commodity derivative gains and losses. Netback received is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. Netback received is equivalent to "operating netback" referenced in the MD&A. The calculation of netback received 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 law. 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.

Currency Presentation

All references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated. The daily rate of exchange on December 31, 2022, as reported by the Bank of Canada for the conversion of Canadian dollars into United States dollars was Cdn.$1.00 equals U.S.$0.7383 and for the conversion of United States dollars into Canadian dollars was U.S.$1.00 equals Cdn.$1.3544. The following table sets forth, for 2022 and 2021, the high, low and average of the daily exchange rates for that year, each for one U.S. dollar expressed in Canadian dollars as reported by the Bank of Canada.

	Year ended December 31, 2022 (Cdn$/Usd)	Year ended December 31, 2021 (Cdn$/Usd)
High	0.8031	0.8306
Low	0.7217	0.7727
Average	0.7692	0.7980

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 (as defined herein), 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, we are in compliance with the NYSE corporate governance standards.

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.

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

"**Alberta EPA**" means the Alberta Ministry of Environment and Protected Areas.

"**AIF**" means this annual information form of the Corporation dated March 1, 2023 for the year ended December 31, 2022.

"**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.

"**CPHL**" means Crescent Point Holdings Ltd.

"**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™ and Dividend Reinvestment Plan of the Corporation.

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

"**ESVP**" means the Employee Share Value Plan of the Corporation.

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

"**Greenhouse Gases**" or "**GHGs**" means any or all of, including but not limited to, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6).

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

"**McDaniel**" means McDaniel & Associates Consultants Ltd.

"**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, 2022.

"**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 and cooperating oil-exporting nations.

"**Partnership**" means Crescent Point Resources Partnership, a general partnership formed under the laws of the Province of Alberta, having CPHL 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.

"**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.

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

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

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

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

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^3	cubic metres
M$	thousand dollars
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
MM$	million dollars
NYMEX	New York Mercantile Exchange natural gas price
tCO2e/boe	tonnes of carbon dioxide equivalent per barrel of oil 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, 2022, 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, natural gas liquids and natural gas reserves in Western Canada and the United States. We make regular cash dividends to Shareholders from our net cash flow.

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 CPHL 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.

CPHL

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

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.

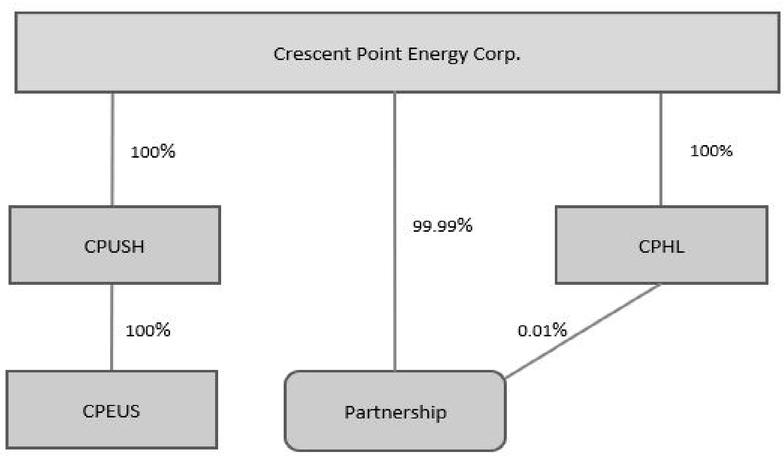
Relationships

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.

	Percentage of Voting Securities (Directly or Indirectly)	Jurisdiction of Incorporation/Formation
CPHL	100%	Alberta
Partnership	100%	Alberta
CPUSH	100%	Nevada
CPEUS	100%	Delaware

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 December 31, 2022 and current to March 1, 2023. 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.

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.

On March 5, 2020, the Corporation announced the approval by the TSX of its notice to implement an NCIB to purchase, for cancellation, 36,884,438 Common Shares, or seven percent of the Corporation's public float, as at February 28, 2020. The 2020 NCIB commenced on March 9, 2020 and expired on March 8, 2021. No purchases were made under the NCIB.

On March 16, 2020, Crescent Point announced that (i) it had revised its 2020 capital expenditures budget to $700 to $800 million, which was expected to generate annual average production of 130,000 to 134,000 boe/d; (ii) it had revised its dividend from $0.01 per share payable every quarter to $0.0025 payable every quarter commencing in the second quarter of 2020; and (iii) all purchases under the NCIB had been deferred.

On April 20, 2020, Crescent Point announced that it had further revised its capital expenditures budget to approximately $650 to $700 million and lowered its production guidance for the year 2020 by 15%, primarily due to the voluntary shut-in of higher cost production.

On June 30, 2020, Crescent Point Holding Inc. transferred its interest in the Partnership to CPHL, a newly incorporated and wholly-owned subsidiary of Crescent Point. Crescent Point Energy Lux S.à r.l. was dissolved effective July 13, 2020.

On July 30, 2020, Myron Stadnyk was appointed to the Board. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

On September 1, 2020, Crescent Point announced that it had reactivated shut-in volumes, which reactivation resulted in expected second half 2020 production increasing by approximately 20 percent to 119,000 to 121,000 boe/d.

2021

On February 17, 2021, the Corporation entered into an agreement with Shell Canada Energy (“**Shell**”), an affiliate of Royal Dutch Shell plc, to acquire Shell’s Kaybob Duvernay assets in Alberta for $900 million. The total consideration consisted of $700 million in cash and 50 million Common Shares. The acquisition closed in April 2021.

On March 5, 2021, the Corporation announced the approval by the TSX of its notice to implement a NCIB (the "**2021 NCIB**") to purchase, for cancellation, 26,462,509 Common Shares, or five percent of the Corporation's public float, as at February 26, 2021. The NCIB commenced on March 9, 2021 and expired on March 8, 2022. The Corporation repurchased a total of 8,602,500 Common Shares under the 2021 NCIB program.

On June 7, 2021 the Corporation completed the disposition of its remaining non-core southeast Saskatchewan conventional assets, which were previously identified as disposition candidates, for cash proceeds of $93 million. As a result of the transaction, Crescent Point also reduced its asset retirement obligations by approximately $220 million, or nearly 25 percent of its asset retirement obligations balance as at March 31, 2021.

On September 13, 2021, the Corporation announced that it was increasing its quarterly dividend from $0.0025 per share payable every quarter to $0.03 per share payable every quarter, commencing with the fourth quarter of 2021.

On December 6, 2021, the Corporation announced that it was increasing its quarterly dividend from $0.03 per share payable every quarter to $0.045 per share payable every quarter, commencing with the first quarter of 2022.

CPHI, a former partner of the Partnership, was dissolved effective December 31, 2021.

2022

On March 4, 2022, the Corporation announced the approval by the TSX of its notice to implement a NCIB (the "**2022 NCIB**") to purchase, for cancellation, up to 57,309,975 Common Shares, or ten percent of the Corporation's public float, as at February 28, 2022. The NCIB commenced on March 9, 2022 and is due to expire on March 8, 2023. In 2022, the Corporation purchased 25,561,600 Common Shares under the 2022 NCIB. As of February 20, 2023, the Corporation had purchased an additional 2,526,900 Common Shares under the 2022 NCIB in 2023.

On May 12, 2022, the Corporation announced that it was increasing its quarterly dividend from $0.045 per share payable every quarter to $0.065 per share payable every quarter, commencing with the second quarter of 2022.

On May 19, 2022, Mindy Wight was elected to the Board. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

On October 26, 2022, the Corporation announced a special dividend of $0.035 per share payable on November 14, 2022.

On December 9, 2022, Crescent Point entered into an agreement to acquire Kaybob Duvernay assets from Paramount Resources Ltd. for cash consideration of $375 million. The acquisition closed in January 2023.

On December 9, 2022, the Corporation announced that it was increasing its quarterly dividend from $0.065 per share payable every quarter to $0.10 per share payable every quarter, commencing with the first quarter of 2023.

2023

On January 11, 2023, Crescent Point completed the acquisition of certain Kaybob Duvernay assets in Alberta for cash consideration of $370.6 million, including closing adjustments, which is expected to be allocated substantially to property, plant and equipment and exploration and evaluation. Cash consideration was funded primarily through cash on hand and included a deposit on acquisition of $18.7 million.

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, natural gas liquids 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 CPHL, 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, natural gas liquids and natural gas reserves and Proved plus Probable (as defined herein) crude oil, natural gas liquids 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, 2022, total dividends declared to shareholders were $0.36 per Common Share. See "*Dividends*".

Strategy

Our strategy is to deliver lasting market-leading value to our stakeholders as a trusted, ethical and environmentally responsible source for energy. We will maintain a resilient, balanced and sustainable portfolio, and apply our agile, diverse, learning mindset to optimize all aspects of our business.

We strive to enhance shareholder returns by cost effectively developing a focused asset base in a responsible and sustainable manner. The Corporation employs a disciplined capital allocation framework centered around returns and balance sheet strength, in order to create value for shareholders through a combination of significant return of capital, returns-based growth and balance sheet strength.

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, multi-stage fracture stimulation of horizontal wells, infill and step-out wells, re-completion of existing wells along with the application of secondary and enhanced oil recovery techniques, including 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, Eastern Europe 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 energy sources;
(i) the effect of energy conservation measures and government regulations;
(j) U.S. and Canada tax policy; and
(k) pandemics, such as the COVID-19 health emergency.

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 return of capital to our shareholders, including payment of dividends and the acquisition of Common Shares.

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 oil 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. For gas 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 50% 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, benchmark natural gas prices are hedged using financial AECO-based instruments transacted in Canadian dollars. Total financial oil and gas hedges in 2022 amounted to approximately 43% of annual production, net of royalties, consisting of approximately 48% of annual liquids production and approximately 21% of annual natural gas production, net of royalties. The Corporation recorded a realized derivative loss on crude oil, NGL and natural gas hedge contracts of $641.8 million in 2022.

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 2022, approximately 10,000 bbls/d of liquids production was contracted with fixed price differentials off WTI. Crescent Point also enters into derivative NYMEX price differential contracts which manage the spread between US$ NYMEX and AECO-based pricing on a portion of its natural gas production.

Refer to the annual financial statements for our commitments under all hedging agreements as at December 31, 2022.

In addition to hedging benchmark crude oil and natural gas prices with financial instruments, we also have the ability to mitigate crude oil basis risk by delivering a portion of our crude oil production into diversified refinery markets using rail transportation when it is economically beneficial to do so. Crescent Point operates two railcar loading facilities, serving its key producing areas of southeast Saskatchewan and southwest Saskatchewan. Crude oil and NGL 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.

We mitigate credit risk by having a well-diversified marketing portfolio for our commodity sales. Credit risk associated with the Corporation's product sales and with the Corporation's financial 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 86 purchasers and its financial hedging portfolio consists of 10 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 may obtain financial assurances such as parental guarantees, prepayments, letters of credit and third party credit insurance. Including these assurances, approximately 98% 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 and British Columbia. During 2022, approximately 59% of our liquids volumes were sold in Saskatchewan, 26% in Alberta, 14% in the U.S. and less than 1% in British Columbia. Approximately 70% of our natural gas volumes were sold in Alberta, 20% in Saskatchewan, 9% in the United States and less than 1% in British Columbia.

For 2022, our commodity production mix was approximately 41% tight oil, 28% NGLs, 16% shale gas, 11% light and medium oil, 3% heavy oil and 1% conventional natural gas.

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

For Year Ended	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas
2022	13.2%	3.2%	51.1%	24.9%	7.1%	0.5%
2021	15.4%	3.4%	55.8%	19.6%	5.3%	0.5%
2020	19.8%	3.6%	66.8%	5.4%	3.6%	0.8%

Competition

We actively compete for reserve acquisitions, exploration leases, licenses 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.

COVID-19 Pandemic

In response to the COVID-19 pandemic, the Corporation continues to monitor the situation and make adjustments to its health and safety protocols as required.

Crude oil and natural gas prices continued to strengthen in 2022, compared to the onset of the COVID-19 pandemic in 2020, as the global recovery from the COVID-19 pandemic and vaccine roll outs facilitated increased mobility, resulting in higher demand for crude oil and crude oil products and lower inventory levels.

Personnel

As of December 31, 2022, the Corporation had 768 permanent employees: 390 employees at the head office in Calgary, 12 employees working remotely in the U.S., 346 field employees in Canada and 20 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 McDaniel with an effective date of December 31, 2022 (the "**Crescent Point Reserve Report**"). The tables below are a combined summary of our crude oil, natural gas liquids, 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 December 31, 2022 forecast price and cost assumptions using the average of three Independent Reserve Evaluators (McDaniel, GLJ Ltd. and Sproule Associates Ltd.). McDaniel evaluated the Corporation's total Proved plus Probable reserves and total Proved plus Probable value discounted at 10% and evaluated all of the Corporation's properties to prepare the Crescent Point Reserve Report. The tables below summarize the data contained in the Crescent Point Reserve Report.

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. 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 McDaniel 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. Legislation 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 carbon emission costs related to government programs are fully integrated into the operating costs and capital unit costs in the reserve evaluation.

The Crescent Point Reserve Report includes the abandonment, decommissioning, and reclamation costs for both the active and inactive locations, including all non-producing and suspended wells, facilities and pipelines. The incremental liabilities from the inactive locations on the total Proved plus Probable reserves is estimated at $208 million of value discounted at 10%. The total impact in the Crescent Point Reserve Report from the combined active and inactive liabilities on total Proved plus Probable reserves is estimated at $308 million of value discounted at 10%.

The Crescent Point Reserve Report is based on certain factual data supplied by Crescent Point as well as McDaniel'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 were supplied by the Corporation to McDaniel, and were accepted without any further investigation. McDaniel 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[1]

	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil		Natural Gas Liquids		Shale Gas		Conventional Natural Gas		Total	
Reserves Category	Company Gross *(Mbbls)*	Company Net *(Mbbls)*	Company Gross *(Mbbls)*	Company Net *(Mbbls)*	Company Gross *(Mbbls)*	Company Net *(Mbbls)*	Company Gross *(Mbbls)*	Company Net *(Mbbls)*	Company Gross *(MMcf)*	Company Net *(MMcf)*	Company Gross *(MMcf)*	Company Net *(MMcf)*	Company Gross *(Mboe)*	Company Net *(Mboe)*
Proved Developed Producing														
Canada	38,102	33,802	18,986	15,886	101,184	94,938	67,238	58,433	248,748	228,852	35,719	32,243	272,920	246,575
United States	—	—	—	—	17,272	14,007	7,272	5,899	23,086	18,726	—	—	28,391	23,026
Total	38,102	33,802	18,986	15,886	118,455	108,945	74,510	64,332	271,834	247,578	35,719	32,243	301,312	269,601
Proved Developed Non-Producing														
Canada	337	323	2,323	2,108	342	320	2,148	1,749	12,140	10,967	69	59	7,185	6,339
United States	—	—	—	—	2,053	1,663	571	462	1,812	1,468	—	—	2,926	2,370
Total	337	323	2,323	2,108	2,395	1,984	2,719	2,211	13,953	12,435	69	59	10,111	8,709
Proved Undeveloped														
Canada	10,757	10,023	1,731	1,583	36,893	34,735	65,878	55,989	225,188	203,979	3,491	3,251	153,372	136,869
United States	—	—	—	—	11,913	9,649	3,375	2,734	10,714	8,678	—	—	17,073	13,829
Total	10,757	10,023	1,731	1,583	48,806	44,385	69,253	58,722	235,901	212,657	3,491	3,251	170,446	150,698
Total Proved														
Canada	49,197	44,148	23,039	19,578	138,419	129,994	135,264	116,171	486,076	443,798	39,279	35,553	433,478	389,782
United States	—	—	—	—	31,238	25,319	11,218	9,095	35,611	28,872	—	—	48,391	39,226
Total	49,197	44,148	23,039	19,578	169,657	155,313	146,482	125,266	521,688	472,670	39,279	35,553	481,868	429,008
Total Probable														
Canada	36,550	32,419	7,230	6,127	75,590	71,050	44,562	35,904	149,035	131,537	23,599	21,366	192,705	170,983
United States	—	—	—	—	25,788	20,896	8,330	6,751	26,445	21,433	—	—	38,525	31,219
Total	36,550	32,419	7,230	6,127	101,378	91,946	52,892	42,655	175,480	152,970	23,599	21,366	231,230	202,203
Total Proved Plus Probable														
Canada	85,747	76,567	30,268	25,705	214,009	201,044	179,827	152,075	635,111	575,335	62,877	56,919	626,182	560,766
United States	—	—	—	—	57,026	46,215	19,548	15,846	62,056	50,305	—	—	86,916	70,445
Total	85,747	76,567	30,268	25,705	271,034	247,259	199,374	167,920	697,167	625,640	62,877	56,919	713,098	631,211

Note:

(1) Numbers may not add due to rounding.

Net Present Value of Future Net Revenue of Oil and Gas Reserves[1]

	Before Income Taxes Discounted at (%/year)						After Income Taxes Discounted at (%/year)					
Reserves Category	0% (MM$)	5% (MM$)	8% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	8% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
Proved Developed Producing												
Canada	8,536	6,778	6,028	5,625	4,850	4,297	7,780	6,265	5,608	5,252	4,566	4,071
United States	871	752	696	664	598	547	858	743	689	657	593	543
Total	9,407	7,530	6,724	6,288	5,448	4,845	8,638	7,008	6,296	5,910	5,159	4,615
Proved Developed Non-Producing												
Canada	277	209	183	170	146	129	208	156	138	128	111	99
United States	129	115	109	106	99	93	123	111	105	102	95	90
Total	406	324	293	276	245	222	331	267	243	230	206	188
Proved Undeveloped												
Canada	4,346	2,958	2,393	2,092	1,522	1,130	3,283	2,175	1,726	1,487	1,037	731
United States	434	341	299	275	227	189	404	315	275	252	205	170
Total	4,779	3,299	2,692	2,367	1,749	1,319	3,686	2,490	2,001	1,739	1,243	901
Total Proved												
Canada	13,159	9,945	8,605	7,887	6,518	5,557	11,270	8,596	7,471	6,867	5,714	4,901
United States	1,433	1,208	1,104	1,045	923	829	1,385	1,169	1,069	1,011	894	803
Total	14,592	11,153	9,709	8,932	7,441	6,386	12,655	9,765	8,540	7,878	6,607	5,704
Total Probable												
Canada	8,152	4,487	3,375	2,854	1,990	1,476	6,171	3,368	2,516	2,118	1,460	1,071
United States	1,227	883	747	675	538	443	987	702	590	531	421	344
Total	9,380	5,370	4,121	3,528	2,528	1,919	7,158	4,070	3,106	2,649	1,881	1,415
Total Proved Plus Probable												
Canada	21,312	14,432	11,980	10,741	8,508	7,033	17,442	11,964	9,988	8,985	7,173	5,973
United States	2,660	2,091	1,851	1,719	1,461	1,272	2,372	1,871	1,659	1,543	1,314	1,147
Total	23,972	16,523	13,831	12,460	9,969	8,305	19,813	13,835	11,646	10,528	8,488	7,120

Note:
(1) Numbers may not add due to rounding.

Additional Information Concerning Future Net Revenue – (Undiscounted)[(1)]

Reserves Category	Revenue (MM$)	Royalties & Burdens[(2)] (MM$)	Operating Costs (MM$)	Development Costs (MM$)	Abandonment and Reclamation Costs[(3)] (MM$)	Future Net Revenue Before Income Taxes (MM$)	Income Tax (MM$)	Future Net Revenue After Income Taxes (MM$)
Proved								
Canada	33,876	3,925	12,205	3,089	1,497	13,159	1,889	11,270
United States	3,927	1,012	1,130	315	37	1,433	48	1,385
Total	37,803	4,937	13,336	3,404	1,534	14,592	1,937	12,655
Proved Plus Probable								
Canada	51,653	6,164	18,075	4,448	1,655	21,312	3,870	17,442
United States	7,228	1,867	1,958	696	46	2,660	288	2,372
Total	58,881	8,031	20,033	5,145	1,701	23,972	4,158	19,813

Notes:
(1) Numbers may not add due to rounding.
(2) Saskatchewan Capital Resource Surcharge, as well as Ad Valorem, have been included under the royalties and burdens column.
(3) In accordance with the Canadian Oil and Gas Evaluation Handbook, abandonment and reclamation costs include: (i) entities with associated reserves included in the Crescent Point Reserve Report, the undiscounted abandonment and reclamation costs associated with these amounts to $843 million and $1.0 billion for Proved and Proved plus Probable, respectively; and (ii) non-reserve entities that include wells with no reserves assigned, suspended wells, pipeline, and facilities, the undiscounted abandonment and reclamation costs associated with these are estimated at $691 million.

Future Net Revenue by Production Type[(1)]

	Future Net Revenue Before Income Taxes[(2)] (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved				
CANADA				
Light and Medium Crude Oil[(3)]	1,037	13.1	19.85	3.31
Heavy Crude Oil[(3)]	398	5.0	20.19	3.36
Tight Oil[(5)]	3,259	41.3	18.88	3.15
Shale Gas[(6)]	3,144	39.9	22.66	3.78
Conventional Natural Gas[(4)]	50	0.6	7.76	1.29
Total Canada	7,887	100	20.23	3.37
UNITED STATES				
Light and Medium Crude Oil[(3)]	—	—	—	—
Heavy Crude Oil[(3)]	—	—	—	—
Tight Oil[(5)]	1,045	100	26.63	4.44
Shale Gas[(4)(6)]	—	—	—	—
Conventional Natural Gas[(4)]	—	—	—	—
Total United States	1,045	100	26.63	4.44
TOTAL				
Light and Medium Crude Oil[(3)]	1,037	11.6	19.85	3.31
Heavy Crude Oil[(3)]	398	4.5	20.19	3.36
Tight Oil[(5)]	4,303	48.2	20.31	3.39
Shale Gas[(4)(6)]	3,144	35.2	22.66	3.78
Conventional Natural Gas[(4)]	50	0.6	7.76	1.29
Total Proved	8,932	100	20.82	3.47

Notes:
(1) Numbers may not add due to rounding.
(2) 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.
(3) Including solution gas and other by-products.
(4) Including by-products, but excluding solution gas.
(5) Including solution gas (categorized as "Shale Gas") and other by-products.
(6) Shale Gas includes the majority of Natural Gas Liquids.

	Future Net Revenue Before Income Taxes[(2)] (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved Plus Probable				
CANADA				
Light and Medium Crude Oil[(3)]	1,710	15.9	18.13	3.02
Heavy Crude Oil[(3)]	493	4.6	19.06	3.18
Tight Oil[(5)]	4,752	44.2	18.13	3.02
Shale Gas[(6)]	3,730	34.7	21.84	3.64
Conventional Natural Gas[(4)]	57	0.5	7.29	1.22
Total Canada	10,741	100	19.15	3.19
UNITED STATES				
Light and Medium Crude Oil[(3)]	—	—	—	—
Heavy Crude Oil[(3)]	—	—	—	—
Tight Oil[(5)]	1,719	100	24.40	4.07
Shale Gas[(4)(6)]	—	—	—	—
Conventional Natural Gas[(4)]	—	—	—	—
Total United States	1,719	100	24.40	4.07
TOTAL				
Light and Medium Crude Oil[(3)]	1,710	13.7	18.13	3.02
Heavy Crude Oil[(3)]	493	4.0	19.06	3.18
Tight Oil[(5)]	6,471	51.9	19.46	3.24
Shale Gas[(4)(6)]	3,730	29.9	21.84	3.64
Conventional Natural Gas[(4)]	57	0.5	7.29	1.22
Total Proved Plus Probable	12,460	100	19.74	3.29

Notes:
(1) Numbers may not add due to rounding.
(2) 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.
(3) Including solution gas and other by-products.
(4) Including by-products, but excluding solution gas.
(5) Including solution gas (categorized as "Shale Gas") and other by-products.
(6) Shale Gas includes the majority of Natural Gas Liquids.

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 in accordance with NI 51-101 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 defense, 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; and

(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, license 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

The average of the three independent reserve evaluator price decks (McDaniel, GLJ Ltd., and Sproule Associates Ltd.) resulted in the following pricing, exchange rate and inflation rate assumptions as of December 31, 2022 in estimating our reserves data using forecast prices and costs.

Year	Crude Oil		Conventional Natural Gas		NGLs					
	WTI at Cushing Oklahoma *($US/bbl)*	Edmonton *($Cdn/bbl)*	Henry Hub NYMEX *($US/ MMBTU)*	AECO/NIT Spot *($Cdn/ MMBTU)*	Pentane Plus Edmonton *($Cdn/bbl)*	Butane Edmonton *($Cdn/bbl)*	Propane Edmonton *($Cdn/bbl)*	Operating Cost Inflation Rate *(%/yr)*	Capital Cost Inflation Rate *(%/yr)*	Exchange Rate *($US/$Cdn)*
Forecast										
2023	80.33	103.76	4.74	4.23	106.22	53.88	39.80	0.0%	0.0%	0.745
2024	78.50	97.74	4.50	4.40	101.35	52.67	39.14	2.3%	2.3%	0.765
2025	76.95	95.27	4.31	4.21	98.94	51.42	39.74	2.0%	2.0%	0.768
2026	77.61	95.58	4.40	4.27	100.19	51.61	39.86	2.0%	2.0%	0.772
2027	79.16	97.07	4.49	4.34	101.74	52.39	40.47	2.0%	2.0%	0.775
2028	80.74	99.01	4.58	4.43	103.78	53.44	41.28	2.0%	2.0%	0.775
2029	82.36	100.99	4.67	4.51	105.85	54.51	42.11	2.0%	2.0%	0.775
2030	84.00	103.01	4.76	4.60	107.97	55.60	42.95	2.0%	2.0%	0.775
2031	85.69	105.07	4.86	4.69	110.13	56.71	43.81	2.0%	2.0%	0.775
2032	87.40	106.69	4.95	4.79	112.33	57.56	44.47	2.0%	2.0%	0.775
2033	89.15	108.83	5.05	4.88	114.58	58.71	45.35	2.0%	2.0%	0.775
2034+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0%	2.0%	0.775

Reconciliations of Changes in Reserves[1]

The following table sets forth a reconciliation of the Corporation's working interest reserves by total Proved, total Probable and total Proved plus Probable reserves as at December 31, 2022, against such reserves as at December 31, 2021, based on forecast price and cost assumptions.

CANADA	Light and Medium Crude Oil *(Mbbls)*			Heavy Crude Oil *(Mbbls)*			Tight Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	61,122	40,574	101,696	24,259	7,255	31,514	147,930	81,170	229,100	118,638	39,126	157,764
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	2,000	741	2,741	93	30	123	2,511	(178)	2,333	20,614	5,283	25,896
Technical Revisions [3]	(1,115)	(2,301)	(3,416)	(447)	(157)	(605)	1,623	(4,778)	(3,154)	3,378	(812)	2,566
Acquisitions [4]	—	—	—	—	—	—	28	8	36	10,016	2,481	12,496
Dispositions [5]	(9,052)	(3,046)	(12,098)	—	—	—	(710)	(1,023)	(1,733)	(7,065)	(1,824)	(8,890)
Economic Factors [6]	1,453	582	2,034	603	102	706	2,416	391	2,807	1,353	310	1,662
Production [7]	(5,210)	—	(5,210)	(1,470)	—	(1,470)	(15,379)	—	(15,379)	(11,668)	—	(11,668)
December 31, 2022	49,197	36,550	85,747	23,039	7,230	30,268	138,419	75,590	214,009	135,264	44,562	179,827

CANADA	Shale Gas (Natural Gas) *(MMcf)*			Conventional Natural Gas (Natural Gas) *(MMcf)*			Total BOE *(Mboe)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	408,722	131,140	539,862	43,612	25,077	68,690	427,338	194,161	621,500
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	90,983	22,017	113,000	684	299	983	40,496	9,595	50,090
Technical Revisions [3]	2,357	(9,583)	(7,226)	(2,149)	(1,955)	(4,104)	3,473	(9,971)	(6,498)
Acquisitions [4]	61,384	15,280	76,664	—	—	—	20,274	5,035	25,309
Dispositions [5]	(38,086)	(10,679)	(48,765)	(1,290)	(371)	(1,661)	(23,390)	(7,735)	(31,125)
Economic Factors [6]	3,646	860	4,506	2,247	549	2,796	6,806	1,620	8,426
Production [7]	(42,930)	—	(42,930)	(3,826)	—	(3,826)	(41,520)	—	(41,520)
December 31, 2022	486,076	149,035	635,111	39,279	23,599	62,877	433,478	192,705	626,182

UNITED STATES	Light and Medium Crude Oil *(Mbbls)*			Heavy Crude Oil *(Mbbls)*			Tight Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2021	—	—	—	—	—	—	33,615	26,698	60,314	11,391	8,616	20,007
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions [3]	—	—	—	—	—	—	838	(1,318)	(480)	1,033	(441)	592
Acquisitions	—	—	—	—	—	—	111	35	146	31	13	44
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors [6]	—	—	—	—	—	—	953	373	1,326	438	142	580
Production [7]	—	—	—	—	—	—	(4,280)	—	(4,280)	(1,675)	—	(1,675)
December 31, 2022	—	—	—	—	—	—	31,238	25,788	57,026	11,218	8,330	19,548

UNITED STATES

Factors	Shale Gas (Natural Gas) *(MMcf)* Proved	Probable	Proved + Probable	Conventional Natural Gas (Natural Gas) *(MMcf)* Proved	Probable	Proved + Probable	Total BOE *(Mboe)* Proved	Probable	Proved + Probable
December 31, 2021	36,162	27,353	63,515	—	—	—	51,033	39,873	90,907
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery	—	—	—	—	—	—	—	—	—
Technical Revisions (3)	2,810	(1,400)	1,410	—	—	—	2,339	(1,993)	347
Acquisitions	98	42	139	—	—	—	158	55	213
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors (6)	1,391	450	1,841	—	—	—	1,623	590	2,213
Production (7)	(4,849)	—	(4,849)	—	—	—	(6,763)	—	(6,763)
December 31, 2022	35,611	26,445	62,056	—	—	—	48,391	38,525	86,916

TOTAL

Factors	Light and Medium Crude Oil *(Mbbls)* Proved	Probable	Proved + Probable	Heavy Crude Oil *(Mbbls)* Proved	Probable	Proved + Probable	Tight Oil *(Mbbls)* Proved	Probable	Proved + Probable	Natural Gas Liquids *(Mbbls)* Proved	Probable	Proved + Probable
December 31, 2021	61,122	40,574	101,696	24,259	7,255	31,514	181,545	107,868	289,413	130,029	47,742	177,772
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (2)	2,000	741	2,741	93	30	123	2,511	(178)	2,333	20,614	5,283	25,896
Technical Revisions (3)	(1,115)	(2,301)	(3,416)	(447)	(157)	(605)	2,462	(6,096)	(3,634)	4,410	(1,253)	3,157
Acquisitions (4)	—	—	—	—	—	—	139	43	182	10,046	2,494	12,540
Dispositions (5)	(9,052)	(3,046)	(12,098)	—	—	—	(710)	(1,023)	(1,733)	(7,065)	(1,824)	(8,890)
Economic Factors (6)	1,453	582	2,034	603	102	706	3,368	764	4,133	1,791	451	2,242
Production (7)	(5,210)	—	(5,210)	(1,470)	—	(1,470)	(19,659)	—	(19,659)	(13,343)	—	(13,343)
December 31, 2022	49,197	36,550	85,747	23,039	7,230	30,268	169,657	101,378	271,034	146,482	52,892	199,374

TOTAL

Factors	Shale Gas (Natural Gas) *(MMcf)* Proved	Probable	Proved + Probable	Conventional Natural Gas (Natural Gas) *(MMcf)* Proved	Probable	Proved + Probable	Total BOE *(Mboe)* Proved	Probable	Proved + Probable
December 31, 2021	444,884	158,493	603,377	43,612	25,077	68,690	478,371	234,035	712,406
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (2)	90,983	22,017	113,000	684	299	983	40,496	9,595	50,090
Technical Revisions (3)	5,167	(10,983)	(5,816)	(2,149)	(1,955)	(4,104)	5,813	(11,964)	(6,151)
Acquisitions (4)	61,482	15,322	76,804	—	—	—	20,432	5,090	25,523
Dispositions (5)	(38,086)	(10,679)	(48,765)	(1,290)	(371)	(1,661)	(23,390)	(7,735)	(31,125)
Economic Factors (6)	5,037	1,310	6,347	2,247	549	2,796	8,429	2,209	10,639
Production (7)	(47,779)	—	(47,779)	(3,826)	—	(3,826)	(48,283)	—	(48,283)
December 31, 2022	521,688	175,480	697,167	39,279	23,599	62,877	481,868	231,230	713,098

Notes:

(1) Numbers may not add due to rounding.

(2) The Corporation's Canadian development strategy focused on continued development of its Kaybob Duvernay asset, along with low risk, infill and development, primarily in the Viewfield, Flat Lake, and Shaunavon resource plays. The Corporation continues its decline mitigation efforts through implementation of waterflood development within its Saskatchewan assets.

(3) The Corporation realized minor positive, performance related revisions in both Canada and the United States. These were offset by negative revisions due to increased operating expenses, as a result of inflationary pressures on costs. Overall, total revisions made up a minor portion of the year-over-year changes.

(4) The Corporation completed a property acquisition and a land swap within its Kaybob Duvernay asset. On January 11, 2023, after the effective date of the reserve report, the Corporation closed an additional acquisition of lands in the Kaybob area for cash consideration of $370.6 million, including closing adjustments. Due to this timing, reserves for these assets are not included in the year-end 2022 reserves.

(5) The Corporation completed dispositions of non-core Southwest Saskatchewan Viking asset, portions of its East Shale Basin Duvernay asset, as well as a land swap within its Kaybob Duvernay asset.

(6) Increases in reserves are due to increases in forecast commodity prices, determined by prior year end reserves calculated on current year end price forecasts.

(7) The Corporation produced an average of 113,752 boe per day in Canada, 18,530 boe per day in the United States for a total of 132,282 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 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 a physical ability, to completely execute on the entire portfolio of booked opportunities within two years, however, approximately 41% of the development spending occurs within this time frame.

The development of these reserves have been based on current and planned capital activity levels, with no material deferrals of development opportunities beyond these normal budgetary constraints. The majority of these reserves are planned to be developed within a three year time frame, which represents approximately 58% of the net undeveloped location count, as well as 63% of the net total future development capital. These development activities are directed mostly to the Corporation's core focus areas of Kaybob Duvernay, Viewfield Bakken, Flat Lake Torquay and Shaunavon resource plays in Canada and the North Dakota Bakken play in the U.S. The current market environment has resulted in long term sustainability. When combined with an extensive location inventory, this results in an extended time period for full development.

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 (Mbbl)		**Heavy Crude Oil (Mbbl)**		**Tight Oil (Mbbl)**		**Natural Gas Liquids (Mbbl)**		**Shale Gas (MMcf)**		**Conventional Natural Gas (MMcf)**		**Oil Equivalent (Mboe)**	
	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End
2020	120	22,242	—	1,420	1,377	79,190	98	19,422	170	70,873	148	10,224	1,647	135,790
2021	4,784	14,353	404	1,677	8,960	61,755	44,358	57,577	137,175	183,576	987	3,468	81,533	166,536
2022	1,108	10,757	—	1,731	167	48,806	25,624	69,253	117,568	235,901	528	3,491	46,581	170,446

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 to seven 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 developed within a three year time frame, representing approximately 45% of the net undeveloped location count, as well as 55% of the total net future development costs. The current market environment has resulted in long term sustainability. When combined with extensive location inventory, this results in an extended full development time period.

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 Kaybob Duvernay, Viewfield Bakken, Flat Lake Torquay and Shaunavon resource plays in Canada and the North Dakota Bakken play in the U.S.

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 (Mbbl)		Heavy Crude Oil (Mbbl)		Tight Oil (Mbbl)		Natural Gas Liquids (Mbbl)		Shale Gas (MMcf)		Conventional Natural Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End
2020	217	31,681	—	1,065	3,753	82,972	437	19,951	1,725	68,679	313	16,844	4,746	149,923
2021	1,190	24,862	693	1,447	1,466	66,758	9,084	27,067	26,750	80,377	640	14,767	16,998	135,991
2022	470	23,332	—	1,481	57	60,050	6,384	29,544	29,397	91,012	236	14,877	11,849	132,055

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 McDaniel, 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$)

	Canada (2)		United States (3)		Total (1)	
Year	**Total Proved**	**Total Proved Plus Probable**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved**	**Total Proved Plus Probable**
2023	468	521	271	401	739	922
2024	608	732	36	232	644	964
2025	763	898	8	63	771	962
2026	624	725	—	—	624	725
2027	552	702	—	—	552	702
2028	52	652	—	—	52	652
2029	4	201	—	—	4	201
2030	5	5	—	—	5	5
2031	6	6	—	—	6	6
2032	2	2	—	—	2	2
2033	1	1	—	—	1	1
2034	1	1	—	—	1	1
Subtotal(1)	3,087	4,446	315	696	3,402	5,143
Remainder	2	2	—	—	2	2
Total(1)	3,089	4,448	315	696	3,404	5,145
10% Discounted	2,432	3,327	293	626	2,724	3,953

Notes:

(1) Numbers may not add due to rounding.

(2) 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 in the reserve report have a similar drilling timing as the Corporation's long-term development plan, with development drilling scheduled to occur within a five year period for Proved reserves, extending up to seven year for Probable reserves.

(3) As in Canada, a large number of Proved as well as Proved plus Probable locations have been booked. The scheduling of locations in the reserve report have a similar drilling timing as the Corporation's long-term development plan, with development drilling scheduled to occur within a three year period for Proved and Probable reserves.

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 properties 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 within North America. The Corporation holds no interests in any plants, facilities or installations that are significant beyond normal oil and gas operating practices. 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, 2022.

Kaybob Area

Kaybob Duvernay production is a combination of natural gas liquids and natural gas, weighted approximately 59% to natural gas liquids. The play is being developed using multi-staged fractured horizontal wells. In 2022, Crescent Point's gross production averaged approximately 37,000 boe per day. 2022 production was made up of approximately 47% condensate. In 2022, the Corporation expanded its Kaybob Duvernay assets with the acquisition of certain Duvernay assets from Repsol Oil & Gas Canada Inc.

In Kaybob, the Corporation spent $281.1 million, representing 29% of its 2022 capital program, drilling 23 (23 net) horizontal wells.

At year-end 2022, the Corporation's Total Proved plus Probable reserves in Kaybob were 202.6 MMboe, with 126 (126 net) drilling locations booked, representing approximately 28% 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 be developed within five years.

As of December 31, 2022, Crescent Point has allocated approximately 32% of the Corporation's 2023 capital budget to developing the Duvernay resource play in Kaybob.

On January 11, 2023, Crescent Point completed the acquisition of certain Kaybob Duvernay assets in Alberta for cash consideration of $370.6 million, including closing adjustments.

North Dakota Area

In North Dakota, the Corporation is developing the Bakken resource play, in which the production is a high-quality light oil and is developed using multi-staged fractured horizontal wells. In 2022, Crescent Point's gross production averaged approximately 19,000 boe per day.

In North Dakota, the Corporation spent $258.9 million, representing 27% of its 2022 capital program, drilling 34 (32.2 net) horizontal wells.

At year-end 2022, the Corporation's Total Proved plus Probable reserves in North Dakota were 86.9 MMboe, with 105 (67.7 net) locations booked, representing approximately 12% 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 be developed within five years.

As of December 31, 2022, Crescent Point has allocated approximately 35% of the Corporation's 2023 capital budget to developing the Bakken resource play in North Dakota.

Viewfield Area

The Viewfield resource area, located in southeastern Saskatchewan, has development in the Bakken resource play, as well as conventional plays including the Frobisher and Midale. In 2022, Crescent Point's production averaged approximately 31,000 boe per day in the area. The majority of production is from the Bakken resource which is a high quality light oil and is exploited using multi-fractured horizontal wells. The core area of the Bakken resource has mostly been unitized, which has allowed for the implementation of various waterflood projects.

Crescent Point spent $165.3 million, representing approximately 17% of its 2022 capital development program, in the Viewfield area including drilling 71 (69.6 net) additional oil wells. The Corporation also continued to focus on waterflood development expansion.

At year-end 2022, the Corporation's total Proved plus Probable reserves in the Viewfield area were 182.9 MMboe, with 630 (588.2 net) locations booked to these reserves. This represents approximately 26% of the Corporation's total Proved plus Probable reserves. Crescent Point expects to fully develop this location inventory within five years for Proved reserves, extending to six years for Probable reserves.

As of December 31, 2022, Crescent Point has allocated approximately 13% of the Corporation's 2023 capital budget to development of the Viewfield area, focused on the Bakken resource play and conventional Frobisher and Midale 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 tight oil Upper and Lower resource plays have been developed using multi-stage fracture stimulated horizontal wells. In 2022, Crescent Point's production averaged approximately 19,000 boe per day in the area.

Crescent Point spent $177.9 million, representing approximately 19% of its 2022 capital development program, in the Shaunavon area including drilling 69 (62.2 net) additional wells. The Corporation has also continued to focus on waterflood expansion and has also initiated a new enhanced oil recovery project in a conventional Upper Shaunavon pool.

As of year-end 2022, the Corporation's total Proved plus Probable reserves in the Shaunavon area were 105.9 MMboe, with 501 (487.5 net) locations booked to these reserves. This represents approximately 15% of the Corporation's total Proved plus Probable reserves. Crescent Point expects to fully develop this location inventory within five years for Proved reserves, extending to seven years for Probable reserves.

As of December 31, 2022, Crescent Point has allocated approximately 9% of the Corporation's 2023 capital budget to development of the Shaunavon area, focused on both Upper and Lower Shaunavon drilling, as well as continued expansion of waterflood and polymer enhanced oil recovery projects.

Oil and Gas Wells

Producing Wells

Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Saskatchewan	5,293	4,733	55	17
Alberta	259	219	407	378
British Columbia	8	5	—	—
TOTAL CANADA	5,560	4,957	462	395
U.S.				
North Dakota	218	175	—	—
TOTAL U.S.	218	175	—	—
Total	5,778	5,132	462	395

Non-Producing Wells

Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Saskatchewan	3,166	2,624	426	139
Alberta	439	338	169	149
British Columbia	1	1	—	—
TOTAL CANADA	3,606	2,963	595	288
U.S.				
North Dakota	32	28	—	—
TOTAL U.S.	32	28	—	—
Total	3,638	2,991	595	288

Notes:
(1) Gross and net producing and non-producing oil and gas counts include both reserve assigned and non-reserve assigned wells.
(2) Active injection wells are reflected in the non-producing well count.

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.

Developed non-producing reserves represent only 2% of the Total Proved reserve category, and 1% of the Total Proved plus Probable reserve category. Wells in the developed non-producing category exist across most of the Corporation's areas and mostly represent wells awaiting final preparation for production, plus those awaiting well reactivation.

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, 2022		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
CANADA			
Alberta	465,620	431,196	67,758
Saskatchewan	592,468	556,338	52,210
Manitoba	2,475	2,475	—
British Columbia	30,610	18,429	—
Total	1,091,173	1,008,438	119,968
U.S.			
North Dakota	20,713	15,278	—
Total	20,713	15,278	—
Total	1,111,886	1,023,716	119,968

The Corporation has no material 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, 2022, in each of Canada and the United States.

	Development Wells		Exploration Wells (2)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil wells	162	151	—	—	162	151
Natural Gas wells	23	23	—	—	23	23
Service wells	—	—	—	—	—	—
Stratigraphic test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total (1)	185	174	—	—	185	174

	Development Wells		Exploration Wells (2)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Oil wells	33	31	—	—	33	31
Natural Gas wells	—	—	—	—	—	—
Service wells	1	1	—	—	1	1
Stratigraphic Test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total (1)	34	32	—	—	34	32

Notes:
(1) Numbers may not add due to rounding.
(2) Exploration wells in this grouping are based on the well license classification at the time of drilling.

For details on important exploration and development activities during 2022, 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 $8.7 billion at December 31, 2022, which are deductible against future taxable income. Based on this tax pool balance and forecast cash flows using December 31, 2022 forecast prices from the average of three Independent Reserve Evaluators (McDaniel, GLJ Ltd. and Sproule Associates Ltd.), with the Corporation's development capital plans, Crescent Point expects to pay income taxes in 2024 of approximately 1% of its forecast cash flow from operations. Crescent Point is subject to other taxes, such as ad valorem taxes, severance taxes, payroll taxes, property taxes, carbon taxes, sales taxes and foreign withholding taxes as part of its ongoing business.

Costs Incurred(1)

The following table summarizes our property acquisition costs, exploration costs and development costs for the year ended December 31, 2022. The total capital costs were approximately $975.3 million in 2022.

($ millions)	Acquisition Costs (2)			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Canada	61.0	28.1	9.4	707.1
U.S.	1.6	—	—	258.8
Total	62.6	28.1	9.4	965.9

Notes:
(1) Costs incurred exclude capitalized administration.
(2) Excludes disposition proceeds of $272.7 million and $10.9 million for proved and unproved properties, respectively.

Production Estimates

The following table discloses for each product type the gross volume of production estimated by McDaniel for 2023 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	3,385	—	102	25,299	95,612	6,869	45,866
Southwest Saskatchewan	2,398	4,393	13,215	374	10,546	632	22,243
Southeast Saskatchewan	7,526	—	23,470	7,539	16,030	2,160	41,567
Total CANADA(1)	13,309	4,393	36,787	33,212	122,188	9,661	109,676
U.S.							
North Dakota and Montana	—	—	18,682	5,328	16,914	—	26,829
Total U.S.(1)	—	—	18,682	5,328	16,914	—	26,829
Total Corporate(1)	13,309	4,393	55,470	38,540	139,102	9,661	136,505

Note:
(1) Numbers may not add due to rounding.

In 2023, production in the Kaybob area of Alberta is estimated at 39,398 boe per day (comprised of 23,537 bbl/d NGLs; 95,166 Mcf/d Shale Gas). Condensate is estimated to make up 47% of 2023 total production from Kaybob. Production at Viewfield in southeast Saskatchewan is estimated at 29,739 boe per day (comprised of 3,661 bbl/d Light & Medium Oil; 17,893 bbl/d Tight Oil; 5,840 bbl/d NGL's; 13,174 Mcf/d Shale Gas; and 900 Mcf/d Conventional Natural Gas). Forecast production for the United States is all from North Dakota. The Kaybob, Viewfield and North Dakota areas make up 29%, 22% and 20% 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 2023.

The following table discloses, for each product type, the gross volume of production estimated by McDaniel for 2023 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	3,499	—	109	26,143	98,198	6,971	47,280
Southwest Saskatchewan	2,480	4,540	14,774	398	11,298	623	24,178
Southeast Saskatchewan	8,273	—	24,883	7,986	16,866	2,490	44,368
Total CANADA(1)	14,252	4,540	39,766	34,527	126,362	10,084	115,826
U.S.							
North Dakota and Montana	—	—	22,900	6,431	20,415	—	32,733
Total U.S.(1)	—	—	22,900	6,431	20,415	—	32,733
Total Corporate(1)	14,252	4,540	62,666	40,958	146,777	10,084	148,559

Note:

(1) Numbers may not add due to rounding.

In 2023, production in the Kaybob area of Alberta is estimated at 40,625 boe per day (comprised of 24,338 bbl/d NGLs; 97,722 Mcf/d Shale Gas). Condensate is estimated to make up 47% of 2023 total production from Kaybob. Production at Viewfield in southeast Saskatchewan is estimated at 31,570 boe per day (comprised of 4,137 bbl/d Light & Medium Oil; 18,810 bbl/d Tight Oil; 6,150 bbl/d NGL's; 13,754 Mcf/d Shale Gas; and 1,085 Mcf/d Conventional Natural Gas). Forecast production for the United States is all from North Dakota. The Kaybob, North Dakota and Viewfield areas make up 27%, 22% and 21% of the Corporation's Proved plus Probable production estimate in the Crescent Point Reserve Report, respectively. Remaining areas each account for a smaller portion of the Corporation's production estimates for 2023.

Production History

The following tables disclose, on a quarterly and annual basis for the year ended December 31, 2022, our share of average daily production volume (prior to deducting royalties), and the prices received, royalties, production costs and transportation costs incurred and netbacks received on a per unit of volume basis for each product type.

Average Daily Production Volume[1]

	Three Months Ended				Year Ended
	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Light and Medium Crude Oil (bbls/d)	15,365	15,752	12,347	13,671	14,274
Heavy Crude Oil (bbls/d)	4,034	4,103	4,102	3,870	4,027
Tight Oil (bbls/d)	43,932	42,553	42,030	40,068	42,134
NGLs (bbls/d)	29,947	30,322	33,668	33,871	31,967
Shale Gas (Mcf/d)	110,898	109,835	121,070	128,437	117,617
Conventional Natural Gas (Mcf/d)	10,045	10,800	10,307	10,769	10,482
Total (boe/d)	113,435	112,836	114,043	114,681	113,752
U.S.					
Light and Medium Crude Oil (bbls/d)	—	—	—	—	—
Heavy Crude Oil (bbls/d)	—	—	—	—	—
Tight Oil (bbls/d)	11,905	10,968	12,000	12,027	11,727
NGLs (bbls/d)	4,827	3,691	4,813	5,022	4,589
Shale Gas (Mcf/d)	15,724	10,089	12,979	14,366	13,285
Conventional Natural Gas (Mcf/d)	—	—	—	—	—
Total (boe/d)	19,353	16,341	18,976	19,443	18,530
TOTAL					
Light and Medium Crude Oil (bbls/d)	15,365	15,752	12,347	13,671	14,274
Heavy Crude Oil (bbls/d)	4,034	4,103	4,102	3,870	4,027
Tight Oil (bbls/d)	55,837	53,521	54,030	52,095	53,861
NGLs (bbls/d) [2]	34,774	34,013	38,481	38,893	36,556
Shale Gas (Mcf/d)	126,622	119,924	134,049	142,803	130,902
Conventional Natural Gas (Mcf/d)	10,045	10,800	10,307	10,769	10,482
Total (boe/d)	132,788	129,176	133,019	134,124	132,282

Notes:
(1) Numbers may not add due to rounding.
(2) For the year ended December 31, 2022, the Company's average condensate production was 19,518 bbl/s, which is included in NGLs production.

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

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	104.07	131.32	116.88	102.99	114.10
Royalties	(15.47)	(20.66)	(23.80)	(18.06)	(19.34)
Production Costs[(1)]	(18.65)	(20.93)	(24.47)	(22.73)	(21.53)
Transportation Costs[(1)]	(2.03)	(2.30)	(2.10)	(1.75)	(2.05)
Netback Received	67.92	87.43	66.51	60.45	71.18
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs[(1)]	—	—	—	—	—
Transportation Costs[(1)]	—	—	—	—	—
Netback Received	—	—	—	—	—
TOTAL					
Prices Received	104.07	131.32	116.88	102.99	114.10
Royalties	(15.47)	(20.66)	(23.80)	(18.06)	(19.34)
Production Costs[(1)]	(18.65)	(20.93)	(24.47)	(22.73)	(21.53)
Transportation Costs[(1)]	(2.03)	(2.30)	(2.10)	(1.75)	(2.05)
Netback Received	67.92	87.43	66.51	60.45	71.18

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

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	101.03	122.53	95.50	77.38	99.34
Royalties	(25.77)	(32.31)	(25.15)	(19.76)	(25.82)
Production Costs[(1)]	(18.11)	(19.53)	(20.00)	(17.08)	(18.70)
Transportation Costs[(1)]	(2.31)	(2.36)	(2.23)	(2.34)	(2.31)
Netback Received	54.84	68.33	48.12	38.20	52.51
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs[(1)]	—	—	—	—	—
Transportation Costs[(1)]	—	—	—	—	—
Netback Received	—	—	—	—	—
TOTAL					
Prices Received	101.03	122.53	95.50	77.38	99.34
Royalties	(25.77)	(32.31)	(25.15)	(19.76)	(25.82)
Production Costs[(1)]	(18.11)	(19.53)	(20.00)	(17.08)	(18.70)
Transportation Costs[(1)]	(2.31)	(2.36)	(2.23)	(2.34)	(2.31)
Netback Received	54.84	68.33	48.12	38.20	52.51

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

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	114.57	134.86	108.60	99.85	114.65
Royalties	(11.23)	(13.78)	(10.78)	(9.95)	(11.45)
Production Costs(1)	(20.53)	(21.50)	(22.74)	(22.04)	(21.69)
Transportation Costs(1)	(4.82)	(4.40)	(5.39)	(5.67)	(5.06)
Netback Received	77.99	95.18	69.69	62.19	76.45
U.S.					
Prices Received	120.91	140.01	122.14	114.72	124.08
Royalties	(31.98)	(37.28)	(34.19)	(31.05)	(33.55)
Production Costs(1)	(17.91)	(17.39)	(16.15)	(13.95)	(16.31)
Transportation Costs(1)	(1.08)	(0.87)	(1.85)	(1.53)	(1.34)
Netback Received	69.94	84.47	69.95	68.19	72.88
TOTAL					
Prices Received	115.92	135.92	111.61	103.28	116.70
Royalties	(15.66)	(18.60)	(15.98)	(14.82)	(16.26)
Production Costs(1)	(19.98)	(20.65)	(21.28)	(20.17)	(20.52)
Transportation Costs(1)	(4.02)	(3.68)	(4.60)	(4.71)	(4.25)
Netback Received	76.26	92.99	69.75	63.58	75.67

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

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	88.55	100.36	86.15	82.75	89.15
Royalties	(11.81)	(11.81)	(9.15)	(8.54)	(10.23)
Production Costs(1)	(9.06)	(10.58)	(9.66)	(10.47)	(9.96)
Transportation Costs(1)	(0.98)	(2.14)	(1.60)	(1.96)	(1.68)
Netback Received	66.70	75.83	65.74	61.78	67.28
U.S.					
Prices Received	52.07	54.89	45.90	36.69	46.16
Royalties	(10.07)	(9.43)	(8.85)	(6.37)	(8.60)
Production Costs(1)	(7.20)	(6.89)	(6.06)	(4.33)	(6.05)
Transportation Costs(1)	(2.90)	(0.86)	(0.34)	(0.39)	(1.12)
Netback Received	31.90	37.71	30.65	25.60	30.39
TOTAL					
Prices Received	83.49	96.42	82.79	78.40	83.76
Royalties	(11.57)	(11.55)	(9.11)	(8.26)	(10.02)
Production Costs(1)	(8.80)	(10.18)	(9.21)	(9.68)	(9.47)
Transportation Costs(1)	(1.25)	(2.00)	(1.44)	(1.76)	(1.61)
Netback Received	61.87	72.69	63.03	58.70	62.66

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

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	5.52	8.05	6.17	6.39	6.52
Royalties[2]	0.02	(0.40)	(0.02)	0.07	(0.08)
Production Costs[1]	(0.67)	(0.93)	(0.80)	(0.92)	(0.83)
Transportation Costs[1]	(0.41)	(0.42)	(0.38)	(0.46)	(0.42)
Netback Received	4.46	6.30	4.97	5.08	5.19
U.S.					
Prices Received	6.07	8.67	10.32	6.61	7.75
Royalties	(1.13)	(1.78)	(2.23)	(1.19)	(1.54)
Production Costs[1]	(0.84)	(1.10)	(1.38)	(0.80)	(1.01)
Transportation Costs[1]	(0.27)	(0.24)	(0.21)	(0.25)	(0.24)
Netback Received	3.83	5.55	6.50	4.37	4.96
TOTAL					
Prices Received	5.59	8.11	6.57	6.42	6.64
Royalties[2]	(0.12)	(0.52)	(0.23)	(0.06)	(0.23)
Production Costs[1]	(0.69)	(0.94)	(0.85)	(0.91)	(0.85)
Transportation Costs[1]	(0.39)	(0.41)	(0.36)	(0.44)	(0.40)
Netback Received	4.39	6.24	5.13	5.01	5.16

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.

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

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2022	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	2022
CANADA					
Prices Received	5.09	7.09	6.29	5.80	6.08
Royalties[2]	0.72	0.92	0.27	0.18	0.52
Production Costs[1]	(0.62)	(0.82)	(0.81)	(0.84)	(0.77)
Transportation Costs[1]	(0.43)	(0.40)	(0.24)	(0.39)	(0.36)
Netback Received	4.76	6.79	5.51	4.75	5.47
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs[1]	—	—	—	—	—
Transportation Costs[1]	—	—	—	—	—
Netback Received	—	—	—	—	—
TOTAL					
Prices Received	5.09	7.09	6.29	5.80	6.08
Royalties[2]	0.72	0.92	0.27	0.18	0.52
Production Costs[1]	(0.62)	(0.82)	(0.81)	(0.84)	(0.77)
Transportation Costs[1]	(0.43)	(0.40)	(0.24)	(0.39)	(0.36)
Netback Received	4.76	6.79	5.51	4.75	5.47

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, 2022 for each product type.

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							
Viewfield	3,943	—	18,697	5,787	12,066	1,133	30,627
Flat Lake	4,180	—	6,572	1,807	2,499	1,444	13,216
Shaunavon	2,376	—	14,029	368	10,798	369	18,634
Kaybob Duvernay	—	—	13	21,882	89,808	23	36,867
Other Canada [2]	3,775	4,027	2,823	2,123	2,446	7,513	14,408
Total CANADA[1]	14,274	4,027	42,134	31,967	117,617	10,482	113,752
U.S.							
North Dakota	—	—	11,727	4,589	13,285	—	18,530
Total U.S.[1]	—	—	11,727	4,589	13,285	—	18,530
Total[1]	14,274	4,027	53,861	36,556	130,902	10,482	132,282

Notes:
(1) Numbers may not add due to rounding.
(2) Includes all remaining assets in Canada.

ADDITIONAL INFORMATION RESPECTING CRESCENT POINT

Directors and Officers

Crescent Point has a board of directors currently consisting of ten individuals. The directors are elected by Shareholders 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 (4) 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
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
Michael Politeski (7) Calgary, Alberta	Senior Vice President, Finance and Treasurer	Not applicable
Shelly Witwer (7) Calgary, Alberta	Senior Vice President, Business Development	Not applicable
Justin Foraie (7) Calgary, Alberta	Vice President, Engineering and Marketing	Not applicable
Barbara Munroe (6) Calgary, Alberta	Director and Chair of the Board	2016
James E. Craddock (2) (3) (5) Whitney, Texas	Director	2019
John P. Dielwart (3) (4) Calgary, Alberta	Director	2019
Ted Goldthorpe (1) (5) New York, New York	Director	2017
Mike Jackson (1) (5) Calgary, Alberta	Director	2016
Jennifer F. Koury (2) (5) Calgary, Alberta	Director	2019
Francois Langlois (1) (3) (4) Calgary, Alberta	Director	2018
Myron M. Stadnyk (2) (3) (4) Calgary, Alberta	Director	2020
Mindy Wight (1) (2) Prince George, British Columbia	Director	2022

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, Safety and Sustainability Committee.
(5) Member of Corporate Governance and Nominating Committee.
(6) Chair of the Board serves in an *ex officio* capacity on each Committee.
(7) Michael Politeski and Shelly Witwer were promoted to Senior Vice President and Justin Foraie was promoted to an Officer of the Corporation, effective January 1, 2023.

As at February 20, 2023, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 2,419,373 Common Shares, representing approximately 0.4% of the issued and outstanding Common Shares. Including restricted shares and options, ownership increased to 1.1% 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 Corporation in 2006, directly overseeing the development and operations of each of Crescent Point's core assets.

Mr. Bryksa is the Chair of the Board of Governors at the Canadian Association of Petroleum Producers ("**CAPP**"). He has significant experience 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 Shelter Bay Energy Inc. and Talisman Energy Inc. in addition to Crescent Point.

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

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 Tétrault 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 honors) 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, LLC as Chief Operating Officer and Fairways E&P, LLC 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.

Michael Politeski, Senior Vice President, Finance and Treasurer

Michael Politeski is the Senior Vice President, Finance and Treasurer. He has held an executive role with the Corporation since joining Crescent Point in March 2015. Mr. Politeski has worked in the oil and gas industry since 2003 in various areas, including treasury and debt capital markets, tax, risk management and insurance, corporate reporting, operational accounting and supply chain management. Prior to joining Crescent Point, Mr. Politeski was the Treasurer and Corporate Controller of Enerplus Corporation and held various management roles with Halliburton Canada and KPMG LLP.

Mr. Politeski is a Chartered Professional Accountant and holds a Bachelor of Commerce degree (with distinction) from the University of Saskatchewan. He is a member of the Institute of Chartered Professional Accountants of Alberta.

Shelly Witwer, Senior Vice President, Business Development

Shelly Witwer is Crescent Point's Senior Vice President, Business Development. Since joining the Corporation in 2007, she has held a number of senior management roles, including Vice President, Land and Vice President, Business Development. Ms. Witwer has significant experience in land and business development roles, having worked with companies such as BP Energy, Burlington Resources and Bear Ridge Resources.

Ms. Witwer is a member of the Canadian Association of Petroleum Landmen and the Petroleum Acquisition and Divestment Association. She holds a Bachelor of Commerce degree and a Bachelor of Arts degree in Energy Economics from the University of Calgary.

Justin Foraie, Vice President, Engineering and Marketing

Justin Foraie is Crescent Point's Vice President, Engineering and Marketing. Mr. Foraie has been with the Corporation since 2009 and has held engineering roles of increasing responsibility, primarily focused on developing the Corporation's United States properties, where he previously served as Vice President, U.S. Operations for CPEUS. Prior to joining Crescent Point, Mr. Foraie worked for Talisman Energy, Inc..

Mr. Foraie has a Bachelor of Applied Science degree in Petroleum Systems Engineering from the University of Regina and is a graduate of the Stanford Graduate School of Business LEAD program. Mr. Foraie became a Registered Professional Engineer in 2008 and is a member of APEGA and Saskatchewan APEGS.

Barbara Munroe, Chair of the Board

Ms. Barbara Munroe was admitted to the Law Society of Alberta in 1991 and brings over 30 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 additionally serves as a Director of ENMAX Corporation and Willow Biosciences Inc., as well as a trustee of the Alberta Cancer Foundation.

Ms. Munroe holds the ICD.D designation and 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. As Chair of the Board, Ms. Munroe serves on each committee in an *ex officio* capacity.

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 served on Noble Energy Inc.'s Board of Directors since its merger with Rosetta Resources Inc. from 2015 to 2020 and served as the Chairman, Chief Executive Officer and President of Rosetta from 2013 to 2015. 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's Eagle Ford Task Force.

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. He is also a Partner in 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. Mr. Dielwart is also Chairman of the Board of TransAlta Corporation. 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 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 CAPP, including 18 months as Chair.

Ted Goldthorpe, Director

Mr. Ted Goldthorpe is a financial professional who has been serving as 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 serves as the CEO and Board Chair of Mount Logan Capital Inc., Portman Ridge Finance Corporation and Logan Ridge Financial Corporation and serves as President and CEO and Chair of Board of trustees of the Alternative Credit Income Fund and Opportunistic Credit Interval Fund. In January 2021, Mr. Goldthorpe was appointed to the Board of KITS Eyewear and also serves as Lead Director.

Mr. Goldthorpe received a Bachelor of Arts 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 on the Board of the Canadian Olympic Foundation, 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 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.

Jennifer F. Koury, Director

Ms. Jennifer F. Koury has over 35 years of professional experience, holding various senior executive positions with BHP Biliton 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 the Vice-Chair of the Board for the Calgary Zoo, Director for Board Ready Women and Director for Bird Construction. She holds a Bachelor of Commerce degree from the University of Alberta and the ICD.D designation granted by the Institute of Corporate Directors.

François Langlois, Director

Mr. Langlois is an oil and gas executive who brings over 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) and the ICD.D designation granted by the Institute of Corporate Directors.

Myron M. Stadnyk, Director

Mr. Myron M. Stadnyk has over 35 years of oil and gas experience and is the former President and CEO of ARC Resources Ltd., retiring in 2020. Mr. Stadnyk was the first operations employee at ARC, after the Corporation's initial public offering, to progress to COO (2005), President (2009) and CEO (2013). Prior to ARC, Mr. Stadnyk worked with a major oil and gas company in both domestic and international operations.

Mr. Stadnyk holds a Bachelor of Science in Mechanical Engineering from the University of Saskatchewan and is a graduate of the Harvard Business School Advanced Management Program and holds an ICD.D designation from the Institute of Corporate Directors. He is a member of APEGA and served as a Governor for CAPP for over 10 years. He also holds Board positions for Prairie Sky Royalty Ltd. and Vermilion Energy, Inc..

Mindy Wight, Director

Ms. Mindy Wight brings over 15 years of tax and financial expertise from her current role of Chief Executive Officer for the Nch'kay Development Corporation. She previously held the role of Chief Financial Officer, as well as holding the role as Treasurer of the Board of Directors.

Prior to joining Nch'kay Development Corporation in November 2021, Ms. Wight held progressive tax roles at MNP LLP from 2016 to 2021 and most recently was a partner and National Leader of Indigenous Tax Services for the firm. Ms. Wight has also worked for two of the Big Four National accounting firms, the Chartered Accounting School of Business and the Canada Revenue Agency since graduating from the University of Northern British Columbia with a Bachelor of Commerce Degree, Accounting in 2007. Ms. Wight also possesses Chartered Professional Accountant, Chartered Accountant, and Certified Aboriginal Financial Manager designations.

Ms. Wight has historically held Board positions as the Chair of the Board of Directors and Chair of the Finance and Audit Committee for the Nch'kay Development Corporation and was an Advisory Committee Member of the Budget and Financial Committee to the Squamish Nation.

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 Corporation 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, except for Mr. Dielwart, who was a director of Denbury Resources Inc. ("**Denbury**") when it entered into Chapter 11 proceedings in the United States on July 30, 2020. Denbury subsequently emerged from Chapter 11 proceedings on September 18, 2020 and Mr. Dielwart resigned as a director of Denbury at that time.

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™ and Dividend Reinvestment Plan

The DRIP was in effect from 2010 until August 2015, when it was suspended.

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.

Restricted Share Bonus Plan

Under the terms of the Corporation's Restricted Share Bonus Plan, any director, officer 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, 2022 the Corporation is authorized to issue up to 11,210,550 Common Shares, of which the Corporation had 2,244,738 Restricted Shares outstanding at December 31, 2022.

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: (i) 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; (ii) to provide participants in the PSU Plan with compensation reflective of their responsibility, commitment and risk accompanying their role over the long-term; and (iii) 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 2,713,176 PSUs outstanding at December 31, 2022.

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 and amended to reduce the maximum number of Common Shares issuable under the Stock Option Plan at the Corporation's annual meeting of shareholders on May 14, 2020. The Corporation has made no stock option ("**Options**") grants in 2022 and does not intend to grant any further Options.

Pursuant to the terms of the Stock Option Plan, a maximum of 10,000,000 Common Shares may be issuable upon the exercise of Options granted under the Stock Option Plan (subject to adjustment for any subdivision or consolidation of the Common Shares). As at December 31, 2022, there were 3,889,130 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 administer 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 determine 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.

Employee Share Value Plan

In early 2020, the Corporation adopted an Employee Share Value Plan ("**ESVP**") for certain employees in lieu of grants that would have previously been made under the Restricted Share Bonus Plan. Under the terms of the ESVP, any employee of the Corporation who, in each case, in the opinion of the Board of Directors, holds an appropriate position with the Corporation to warrant participation in the ESVP (collectively, the "**ESVP Participants**") may be granted rights ("**Awards**") which vest over time and, upon vesting, entitle the participant to receive a cash payment for each Award equal to the five day weighted average trading price on the TSX of the Common Shares immediately preceding the vesting date plus an amount equal to the aggregate amount paid by the Corporation in dividends per Common Share from the grant date of an Award to and including the vesting date (collectively, the "**Payout Value**"). ESVP Participants do not have any right to receive Common Shares in respect of vested Awards.

Awards vest as to 33 1/3% on each of the first, second and third anniversaries of the grant date as determined by the Board of Directors. Upon vesting of an Award, the Corporation is required to pay to an ESVP Participant the Payout Value within 15 business days of vesting and, in all cases, prior to December 31 of the year of vesting.

The Employee Share Value Plan is administered by the Board of Directors. At December 31, 2022, there were 5,274,478 awards outstanding.

Long-Term Debt

At December 31, 2022, the Corporation had a $2.26 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 eleven banks and has a maturity date of November 26, 2026. The current maturity date of the Bi-Lateral Credit Facility is November 26, 2026. The Syndicated Credit Facility's interest rate is based on either Canadian prime rate, U.S. base rate, Secured Overnight Financing 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 restricted subsidiaries currently being CPEUS, CPUSH, CPHL and the Partnership. Various borrowing options are available under the Credit Facilities, including Canadian prime rate-based advances, U.S. base rate-based advances, Secured Overnight Financing 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 and share repurchases 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, 2022, the Corporation was undrawn on its bank credit facilities.

At December 31, 2022, the Corporation had approximately $1.4 billion of senior guaranteed notes ("the Senior Guaranteed Notes") outstanding of which $538.7 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$921.0 million Senior Guaranteed Notes, the Corporation entered into cross currency swaps to hedge its foreign exchange exposure, fixing a notional amount of $1.05 billion for the purpose of interest and principal repayments.

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.

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.

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 Canada Energy Regulator (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 license from the CER and the issue of such a license requires the approval of the Governor in Council.

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 ("**PPI-FG**") plus 1.23% should be the index level for the five-year period beginning July 1, 2016. In December 2020, the FERC adjusted the index level to be the PPI-FG plus 0.78% for the July 1, 2021 to June 30, 2026 time period. 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.

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 license. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

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 inter-state or international sales 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. Although FERC has set forth a general test to determine whether facilities are exempt from FERC jurisdiction as "gathering" facilities, FERC's determinations as to the classification of facilities are performed on a case-by-case basis and FERC has the authority to reclassify facilities previously thought to be non-jurisdictional. 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 licenses imposed by the DOE. Natural gas may not be exported from Canada without a license or order from the CER or imported into the United States or exported from the United States without a license from the DOE. Licenses 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, for export, may be obtained for a period that does not exceed 40 years. In Canada the approval of the Minister of Natural Resources and the Governor in Council is currently required prior to the issuance of a license to export natural gas. Alternatively, natural gas may be exported from Canada pursuant to an order from the CER. Orders may be obtained for a period of two years or less or for a period greater than two years but less than 20 years, where the quantity is not more than 30,000 m^3/day. Orders do not require the approval of the Governor in Council or the Minister of Natural Resources. Any person who imports oil or gas into Canada must provide prescribed information in the prescribed form and manner to the CER, but does not require a license. 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 Canada-United States-Mexico Agreement and The North American Free Trade Agreement

On July 1, 2020, the Canada-United States-Mexico Agreement ("**CUSMA**") came into force replacing the North American Free Trade Agreement ("**NAFTA**").

Relevant to the energy industry, CUSMA does not contain the proportionality rules found in NAFTA's Article 605 whereby 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.

CUSMA also eliminates certain tariffs on some diluents used to transport heavy oil from Canada to the U.S.

There has been little to no effect on Canada's energy industry by the ratification of CUSMA and Crescent Point has not experienced any significant change to its operations or marketing activities as a result of the ratification of CUSMA.

Royalties and Incentives

In addition to federal regulation, each province (and in the case of the U.S., each state) has legislation with respect to oil and gas activities, governing matters such as 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 December 31, 2016. 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 are 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 zero to a cap of 40%.

The Old Framework also includes a natural gas royalty formula, which formula 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 Alberta 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, including the Enhanced Oil Recovery Royalty Program (the "**EOR Program**") were created pursuant to the Old Framework.

Under the EOR Program, 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.

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% 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% on revenues until their combined revenue equals their combined program specific cost allowances established under the ERP, which 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 provincial 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**").

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 provincial 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 17% of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the provincial 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 SMER 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^3, 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^3. 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^3, 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^3.

In December 2018, the Government of Saskatchewan introduced the Waterflood Development Program (the "**WDP**"), which program offers repayable royalty and freehold production tax deferrals for eligible wells that have been converted to injection wells or newly drilled injection wells for the purpose of waterflooding an oil reservoir. Under the WDP, royalty and freehold production taxes can be deferred for a period of three years and can be used alongside other incentive grant programs available in Saskatchewan.

In June of 2019, the Government of Saskatchewan introduced the Saskatchewan Petroleum Innovation Incentive ("**SPII**"). SPII offers transferable royalty and freehold production tax credits for qualified innovation commercialization projects at a rate of 25% of eligible project costs, targeting a broad range of innovations across all segments of Saskatchewan's oil and gas industry.

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.

In March 2020, the Government of Saskatchewan introduced the Oil Infrastructure Investment Program ("**OIIP**"), which program offers transferable oil and gas royalty and freehold production tax credits for qualified projects at a rate of 20 percent of eligible project costs (with a minimum $10 million investment). OIIP is open to new or expanded oil, refined petroleum products or natural gas liquids, including transmission pipelines, feeder pipeline and pipeline terminals. As of November 4, 2021, carbon dioxide pipeline projects became eligible for OIIP, including pipeline projects to be used for transporting carbon dioxide for carbon capture and storage or for EOR projects.

Effective April 1, 2021, Saskatchewan amended the High Water-Cut Oil Well Program, which program provides a royalty status re-assignment for qualifying high water-cut oil wells that incur an average minimum investment of $20,000 per well, made on or after April 1, 2021, to directly improve water handling capabilities and extend the producing life of the well. Such eligible wells drilled before October 1, 2002 will receive fourth tier royalties on all future incremental high water-cut oil production, and wells drilled on or after October 1, 2002 will obtain a 2 percent royalty rate reduction on all future oil production.

On April 6, 2021, the Government of Saskatchewan introduced the Associated Gas Royalty Moratorium, which is a moratorium on the collection of Crown royalty and freehold production tax on associated gas produced from wells other than gas wells, including natural gas produced from oil wells. The moratorium has been implemented as part of Saskatchewan's Methane Action Plan to assist producers in meeting regulatory obligations to reduce methane-based greenhouse gas emissions by 40-45 percent between 2020 and 2025. The moratorium applies to associated natural gas produced on or after April 1, 2021, and before April 1, 2026.

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, an Indigenous tribe or person, 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 1/8 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.

The North Dakota Industrial Commission (the "**NDIC**") regulates the drilling and production of crude oil and natural gas in North Dakota. Over the past decade, the NDIC has adopted more stringent rules relating to production activities, including waste discharges and storage, financial assurance for wells and underground gathering pipelines, hydraulic fracturing, and associated public disclosure on the FracFocus chemical disclosure registry. Additionally, in response to North Dakota natural gas production reaching record highs and flaring levels exceeding the state's limit of acceptable levels, the NDIC announced an initiative in 2014 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. Specifically, the NDIC established requirements on oil and gas operators to capture, and thus not flare, a designated percentage of the natural gas produced from wells in North Dakota, subject however, to numerous exceptions and variances. For the period ending October 31, 2020, the gas capture requirement was 88%, which was increased to 91% for periods on and after November 1, 2020. If the applicable gas capture requirement is not met, potential penalties may be imposed unless an exception or variance applies. 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.

Finally, the NDIC has adopted rules that improve the safety standards for transporting Bakken crude oil by establishing operating standards for conditioning equipment to properly separate production fluids, limits to the vapor pressure of produced crude oil, and parameters for temperatures and pressures associated with the production equipment.

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 sensitive receptors.

Canada

Provincial environmental legislation in the Province of Alberta for the oil and gas industry 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 *Technology and Emissions Reductions Implementation Act, 2019,* 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. Provincial 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, The Oil and Gas Conservation Act*, *The Pipeline Act, 1998* and *The Management and Reduction of Greenhouse Gases Act* which regulate harmful or potentially harmful activities and substances and GHGs, 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*. Provincial 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, pipelines 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 licenses 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 with respect to the AER liability management programs in Alberta and published by SMER in Directive PNG025 Financial Security Requirements 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.

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* ("**CERCLA**") and comparable state statutes impose strict, joint and several, and retroactive 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 or private parties to file claims requiring cleanup actions, demands for reimbursement for cleanup costs, or natural resource damages, or for neighboring landowners and other third parties to file tort claims for bodily 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. Additionally, on September 6, 2022, the US Environmental Protection Agency (the "**EPA**") published a Proposed Rule to designate two per and polyfluoroalkyl substances ("**PFAS**") perfluorooctanoic acid ("**PFOA**") and perfluorooctane sulfonic acid ("**PFOS**") as "hazardous substances" under CERCLA. If these PFAS are listed as CERCLA hazardous substances and PFAS contamination is detected at sites that we currently own or operate, or formerly owned or operated, we may be obligated to remediate those areas.

The federal *Solid Waste Disposal Act,* as amended by the *Resource Conservation and Recovery Act*, (collectively, "**RCRA**") and comparable state statutes regulate the generation, transportation, treatment, storage and 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. Under the RCRA oil and gas exploration and production waste ("**E&P waste"**) exemption, E&P waste is regulated as a "solid waste" rather than a "hazardous waste." However, these E&P wastes may still be regulated under state solid waste laws and regulations. On several occasions in the past decade, environmental groups have sued the EPA for failing to update and revise RCRA regulations, including the regulations governing E&P waste. In each case, EPA has determined that regulatory revisions are not necessary. However, there remains a risk that the EPA could make changes in the current RCRA E&P waste exemption, which, in turn, could result in an increase in the costs to manage and dispose of wastes. Additionally, there is a risk that certain states may regulate E&P wastes more stringently, which could also result in an increase in the costs to manage and dispose of wastes. Also, ordinary industrial wastes that are not uniquely associated with oil and gas exploration and production operations, 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 E&P waste 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 their 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, would change the scope of the rule’s application. In August 2019, the Trump administration issued three final rules regarding implementation of the ESA (the "**2019 Rules**"). Under the new rules, the administration changed the considerations for listing, delisting or reclassifying species. The 2019 Rules limit 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 2019 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 removed the phrase "without reference to possible economic or other impacts of such determination" of a species' status, which could 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, making it a case-by-case determination. These new rules applied only towards future listing of species, and significantly limited the scope of the ESA. However, the Biden administration announced in June 2021, that it will formally introduce regulatory proposals to rescind changes the Trump administration made to the ESA regulations. The rules also are being challenged in federal courts in California and Hawaii, and in November 2022, the California court decided to leave the rules in effect pending remand to the U.S. Fish and Wildlife Service ("**FWS**"). The Biden administration has not yet proposed new rules.

Additionally, the Biden administration announced in October 2021 that it will formally introduce regulatory proposals to rescind other changes the Trump administration made to the ESA regulations. On June 24, 2022, the Biden administration published a final rule that rescinded the Trump administration's definitions of "habitat", finding that the definition impeded the FWS's ability to designate critical habitat based on the best scientific data available. Similarly, on July 21, 2022, the FWS published a final rule rescinding the Trump administration's rules that changed the FWS's process for excluding areas from critical habitat designation and undertaking exclusion analyses, thus reinstating the rules in place prior to 2021. If the Biden administration continues to rescind the Trump administration's revisions to the ESA regulations, we, as well as our competitors, would be expected to incur increased operating expenses and potential delays in our operations in the United States. 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* ("**NEPA**") requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal and certain Indigenous 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 July 16, 2020, the White House Council on Environmental Quality ("**CEQ"**) published a Final Rule revising NEPA's implementing regulations (the "**2020 Rule**"). The changes to NEPA introduced a "non-major" category which would exempt certain types of governments, allowing them to move forward without an environmental assessment. The changes also eliminate reference to "cumulative" effects and focus more on causation. This would 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. The 2020 Rule would make the NEPA process more efficient and less time consuming by streamlining the entire process and proposing page and time limits. Additionally, the Final Rule introduced additional responsibilities for commenters. For example, comments would 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. The Final Rule would likely result in a quicker turnaround time for obtaining leases and permits. Twenty-three states and several environmental groups filed two separate lawsuits in California federal court challenging the Final Rule. Notably, on January 20, 2021, President Biden issued Executive Order 13990, which directed federal agencies to immediately review and take action to address the promulgation of federal regulations during the previous administration that conflicted with important national objectives. The Executive Order specifically identified the 2020 Rule as subject to the Executive Order's requirements. Accordingly, on February 12, 2021, the California District Court issued a stay in both cases to provide CEQ with adequate time to reconsider the 2020 Rule, as directed by the Executive Order. The two lawsuits are currently stayed to accommodate revision of the rules.

In addition, in October 2021, the CEQ published a notice of proposed rulemaking (the "**2021 Proposed Rule"**) to reverse several of the Trump administration’s revisions to the NEPA implementing regulations. The 2021 Proposed Rule seeks to revise three aspects of the 2020 Rule back to the prior regulations with minor modifications: (i) the “purpose and need” of a proposed action; (ii) the definition of "effects," restoring the prior definitions of direct, indirect, and cumulative effects; and (iii) agency flexibility to develop NEPA implementation procedures that go beyond the CEQ regulatory requirements. CEQ published the 2021 Proposed Rule as a final rule on April 20, 2022, and the rule became effective May 20, 2022. CEQ has announced that it intends to propose a second phase of rulemaking to implement additional revisions to the 2020 Rule to ensure efficient and effective environmental reviews, provide regulatory certainty, promote better decision-making and address climate change and environmental justice objectives.

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. To the extent the agencies' are expanding the range of properties subject to the CWA jurisdiction, certain energy companies could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas, which in turn could reduce demand for our services. 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. 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 April 21, 2020, the EPA and U.S. Army Corps of Engineers ("**USACE**") released a final rule to define WOTUS (the "**2020 WOTUS Rule"**) that identified four categories as jurisdictional WOTUS: (i) 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; (ii) 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; (iii) ditches, which are artificial channels used to convey water that are either TNWs, constructed in a tributary, or constructed in an adjacent wetland; (iv) 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; (v) impoundments of other jurisdictional WOTUS; and (vi) 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.

However, the 2020 WOTUS Rule was vacated by two separate federal district courts in late 2021. On November 18, 2021, EPA and USACE issued a pre-publication version of another rule largely reinstating the previous 1986 WOTUS rule and guidance "with certain amendments" to reflect "consideration of the agencies statutory authority under the CWA and relevant Supreme Court decisions" (the "**2021 Proposed Rule"**). The 2021 Proposed Rule was published in the Federal Register on December 7, 2021. In addition to the 2021 Proposed Rule, the EPA and USACE plan to develop yet another amendment to the WOTUS regulations, which will build upon the regulatory foundation in the 2021 Proposed Rule with the benefit of additional stakeholder engagement and public input. In September 2022, EPA and USACE sent the draft final rule to implement the 2021 Proposed Rule to the Office of Management and Budget for interagency review, but no final rule has yet been issued by the agencies. It is unknown at this time when the 2021 Proposed Rule will take effect; when the next forthcoming proposed amendments are expected; and/or whether either new rule will be challenged and withstand any challenges in federal court. Finally, in January 2022, the United States Supreme Court granted review of Sackett vs. EPA, which involves issues related to CWA scope and jurisdiction and could impact the current rulemaking process. The Supreme Court heard oral argument in Sackett on October 3, 2022, and a decision is expected in 2023. Although the outcome of the 2021 Proposed Rule and additional forthcoming amendments to the WOTUS regulations is unknown, the regulations under the Biden Administration are undoubtedly more stringent in terms of the scope of WOTUS, which could ultimately change the scope of the CWA's jurisdiction and result in increased costs and delays with respect to obtaining permits for discharges of pollutants or dredge and fill activities in waters of the U.S., including regulated wetland areas. However, the definition of "WOTUS" and how it has been applied has been in flux over the last several years, both via administrative rulemakings and actions and judicial interpretation and intervention. Thus, the fate of the definition of "WOTUS" under the CWA and how that ultimately will be applied by the Agencies is yet to be seen.

On January 19, 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. On January 18, 2022, EPA issued its 2022 CGP for stormwater discharges from construction activities involving more than one acre. The 2022 CGP, which became effective February 17, 2022, replaces the 2017 CGP. The 2022 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 2022 CGP provides permit coverage for certain stormwater discharges from construction activities at facilities where EPA is the permitting authority for a five-year period through February 16, 2027.

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, previously have been introduced in Congress, without success. However, with the changes in the U.S. presidential administrations and the control of Congress, such legislation may have a better chance of passing in the future. In addition, the EPA at the request of Congress 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.

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 incurring other unexpected material costs or liabilities.

The *Clean Air Act* ("**CAA**"), as amended, restricts the emission of air pollutants from many sources, including oil and gas operations. The CAA 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. CAA 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 (the "**2016 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 required 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 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.

In September 2020, the EPA finalized a new rule that amended the 2016 Rule (the "**2020 EPA Rule**"). In the 2020 EPA Rule, the EPA removed all sources in the transmission and storage segment of the oil and natural gas industry from regulation. The 2020 EPA Rule also rescinded the methane requirements in the 2016 Rule and reduced monitoring frequencies. On June 30, 2021, President Biden signed into law a joint Congressional resolution disapproving and invalidating much of the 2020 EPA Rule under the prior Administration, including the 2020 EPA Rule's rescission of the methane requirements.

On November 15, 2021, EPA published a proposed rule that would update and expand existing requirements for the oil and gas industry, as well as create significant new requirements and standards for new, modified and existing oil and gas facilities. The proposed new requirements would include, for example: (i) updated and broadened methane and volatile organic compound emission reduction requirements for new, modified, and reconstructed oil and gas sources, including standards that limit emissions from additional types of sources (such as intermittent vent pneumatic controllers, associated gas, and well liquids unloading); and (ii) requirements that states develop plans to limit methane emissions from hundreds of thousands of existing sources nationwide, along with presumptive standards for existing sources to assist in the planning process. Key features of the November 2021 proposed rule include:

- a comprehensive monitoring program for new and existing well sites and compressor stations;
- a compliance option that allows owners and operators the flexibility to use advanced technology that can find major leaks more rapidly and at lower cost;
- a zero-emissions standard for new and existing pneumatic controllers;
- standards to eliminate venting of associated gas, and require capture and sale of gas where a sales line is available, at new and existing oil wells;
- proposed performance standards and presumptive standards for other new and existing sources, including storage tanks, pneumatic pumps, and compressors; and
- a requirement that states meaningfully engage with overburdened and underserved communities, among other stakeholders, in developing state plans.

On November 8, 2022, EPA published a supplemental proposal to update, strengthen, and expand the standards proposed in November 2021. The proposed rules for new and modified facilities are estimated to be finalized by the end of 2023, while any standards finalized for existing facilities will require further state rulemaking actions over the next several years before they become applicable and effective. If this proposed rule is implemented, it would be expected to cause us, as well as our competitors, to incur increased operating expenses.

We are subject to a number of federal and state laws and regulations, including the federal *Occupational Safety and Health Act* ("**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. Specifically, OSHA has enacted a regulation regarding crystalline silica exposures, which included requirements that hydraulic fracturing operations implement dust controls to limit exposures to the substance.

Transportation and safety of natural gas is also subject to regulation by the U.S. Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration ("**PHMSA"**), under the *Natural Gas Pipeline Safety Act* of 1968, as amended, which imposes safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities, the *Pipeline Inspection, Protection, Enforcement and Safety Act* of 2006, the *Pipeline Safety, Regulatory Certainty and Job Creation Act* of 2011, and the *Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act)* of 2020. In November 2021, PHMSA issued its final rule extending reporting requirements to all onshore gas gathering operators and applying a set of minimum safety requirements to certain onshore gas gathering pipelines with large diameters and high operating pressures. Furthermore, in August 2022, PHMSA published a final rule in the Federal Register that establishes new standards for identifying threats, potential failures, and worst-case scenarios resulting from pipeline incidents. The final rule also institutes new management of change requirements, strengthens PHMSA's integrity management requirements and corrosion control standards, and implements new requirements for inspections after extreme weather events. The final rule becomes effective on May 24, 2023. These new rules could bring certain pipelines under federal scrutiny for the first time and/or increase the cost of compliance with PHMSA's standards.

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 fostering 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) an emission reduction and trading system for large industry, known as the output-based pricing system ("**OBPS**"); and (ii) a regulatory charge on 21 types of fuel, commonly known as the carbon tax. Each province was given the choice to either accept the federal requirement 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 $50 per tonne of GHG emissions in 2022 and will increase to $65 per tonne in 2023 and then by $15 per tonne per year until it reaches $170 per tonne in 2030.

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 per year must report their emissions to Environment and Climate Change Canada. On June 21, 2022, the federal government also brought into force the *Clean Fuel Regulations* which set emission limits on a variety of liquid fuels, including gasoline and diesel.

On July 18, 2022, the federal government published a discussion paper on two options to implement a cap on oil and gas emissions, being either a new cap and trade system or modification to the OBPS. The precise timing of the federal government's next steps in developing the oil and gas cap will depend upon the option chosen and the final design of the cap. The oil and gas emissions cap is expected to set out a specific trajectory for the oil and gas sector to achieve net zero emissions by 2050.

In Alberta, GHG emissions are regulated under the *Emissions Management and Climate Resilience Act* and the TIER Regulation, which came into effect January 1, 2020. The TIER system is mandatory for large emitters, being those that emit 100,000 tonnes or more of GHGs per year, however, facilities with less than 100,000 tonnes per year can voluntarily opt into the system by aggregating two or more smaller facilities together. Registered facilities are required to reduce their emission intensity (tCO2e/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 and flaring. Crescent Point has two aggregate facilities registered in the TIER system.

On December 15, 2022, the Government of Alberta announced amendments to TIER which became effective on January 1, 2023, which amendments include meeting federal emission reduction requirements for 2023 through 2030, compliance flexibility and increasing the regulator stringency.

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 ("**the Saskatchewan OBPS**") were developed to reduce emissions intensity associated with stationary fuel combustion by 15% by 2030, however, subsequently, effective January 1, 2023, emissions intensity associated with stationary fuel combustion and flaring were reduced by 20% by 2030. Under the Saskatchewan OBPS program operators of certain large facilities that emit 25,000 tonnes or more of GHGs per year must register. Additionally, a voluntary aggregated facility (two or more smaller facilities grouped together) can also register in the OBPS program. Operators must reduce their emissions per unit of production from their historical emissions and 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 in the Saskatchewan 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 Saskatchewan OBPS program.

On November 22, 2022, the Government of Saskatchewan announced amendments to the Saskatchewan OBPS to meet the requirements of the 2023-2030 national carbon pricing benchmark. Effective January 1, 2023, the regulated emissions under the Saskatchewan OBPS were expanded to include flaring and the emission intensity reduction was increased to 20%.

U.S. Greenhouse Gas Emissions Permitting and 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 developed and implemented regulations that restrict GHG emissions under existing provisions of the federal 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 "tailored" 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.

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 issued regulations that limit GHG emissions including those associated with our operations which will require us to incur costs to inventory and reduce GHG emissions associated with our operations.

On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022 ("**IRA"**). The IRA imposes a fee of up to $1,500 per metric ton of methane emitted above specified thresholds from onshore petroleum and natural gas production facilities, natural gas processing facilities, natural gas transmission and compression facilities, and onshore petroleum and natural gas gathering and boosting facilities, among other facilities. The fees will apply to methane emissions after January 1, 2024. Congress may adopt additional significant legislation in the future to reduce emissions of GHGs.

On November 30, 2022, the U.S. Bureau of Land Management ("**BLM**") published a proposed rule that would regulate venting, flaring, and leaks of natural gas occurring during oil and gas production activities on federal and Indigenous leases. If finalized as proposed, the rule would limit gas that may be flared royalty-free during well completions, production testing, and emergencies; establish a monthly volume limit on royalty-free flaring due to pipeline capacity constraints, midstream processing failures, or other similar events; require vapor recovery systems on oil tanks; require operators to maintain leak detection and repair programs; prohibit the use of certain natural-gas-activated pneumatic controllers and pneumatic diaphragm pumps; and require operators to submit waste minimization plans with applications for permits to drill, among other requirements.

Although the U.S. had withdrawn from the Paris Agreement, the Biden administration has issued executive orders recommitting the U.S. to the Paris Agreement and calling for the federal government to begin formulating the U.S.' nationally determined emissions reduction goal under the Paris Agreement. In April 2021, President Biden announced that the United States would aim to cut its greenhouse gas emissions 50 to 52 percent below 2005 levels by 2030. This commitment will be part of the United States' "nationally determined contribution", or NDC, to the Paris Climate Agreement. The NDC will commit the United States to a voluntary GHG emission reduction target and outline domestic climate mitigation measures to achieve that target. With the U.S. recommitting to the Paris Agreement, additional executive orders may be issued or federal legislation or regulatory initiatives may be adopted to achieve the Paris Agreement's goals.

On January 27, 2021, the Biden administration also issued an executive order that commits to substantial action on climate change, calling for, among other things, suspending the issuance of new leases for oil and gas development on federal lands, pending completion of a review of leasing and permitting practices and expanding on the Acting Secretary of the U.S. Department of the Interior's January 20, 2020, order, effective immediately, that suspended new oil and gas leases and drilling permits on federal lands and waters for a period of 60 days. The executive order also called for the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and an increased emphasis on climate-related risks across government agencies and economic sectors. In June 2021, a federal judge in Louisiana preliminarily enjoined the administration's suspension of oil and gas leasing on federal lands and waters. In August 2021, the administration appealed that ruling to the Fifth Circuit, and on August 17, 2022, the Fifth Circuit vacated and remanded the Louisiana court's preliminary injunction, holding that the order lacked specificity. The following day, however, the Louisiana court permanently enjoined the suspension. In 2022, the DOI resumed oil and gas leasing on federal onshore public lands on a limited basis, which is still pending. The Biden administration could also impose more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emissions limitations for oil and gas facilities. Litigation risks are also increasing, as a number of cities and other local governments have sought to bring suit against fossil fuel producer companies in state or federal court, alleging that such companies created public nuisances by producing fuels that contributed to global warming effects.

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. In addition to the federal legislative and regulatory changes, 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.

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 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 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^3 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 came 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.

Operators of upstream oil and gas facilities are required to: 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^3 of hydrocarbon gas or greater annually; complete annual measurements of emissions from natural gas compressor vents to ensure emissions are under the applicable limit; and eliminate venting from well completions involving hydraulic fracturing.

Beginning in 2023, operators of upstream oil and gas facilities will be required to: meet a venting limit of 15,000 m^3 of gas per year at facilities that produce and/or receive more than 60,000 m^3 of gas per year, and 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.

On October 11, 2021, the Canadian federal government announced its support for the Global Methane Pledge, which aims to reduce global methane emissions by 30 percent below 2020 levels by 2030. In support of the Global Methane Pledge, Canada announced its commitment to developing a plan to reduce methane emissions across the broader Canadian economy and to reducing oil and gas methane emissions by at least 75 percent below 2012 levels by 2030, and that these goals will be achieved through an approach that will include regulation.

In September 2022, the Government of Canada released Canada's Methane Strategy with the aim of reducing domestic methane emissions, including a new target of reducing absolute methane emissions from the oil and gas sector by 75% by 2030 relative to 2012. In November 2022, the Government of Canada released a Proposed Regulatory Framework for Reducing Oil and Gas Methane Emissions to Achieve 2030 Target. The proposed changes will expand the scope of the existing regulations to apply to a wider set of sources, including all facilities handling natural gas, increasing the scope and frequency of inspection programs, requiring certain non-emitting equipment when feasible, prohibiting flaring at oil sites, limiting venting of methane and requiring fugitive methane emissions management plans.

Currently the federal regulations do not apply in provinces which the federal government deems to have equivalent methane reduction regulations. Alberta, Saskatchewan and British Columbia have each reached equivalency agreements with the federal government and currently operators in these provinces are subject to only the provincial methane reduction requirements.

In Alberta, new design specifications have been put in place by 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.

Crescent Point's operations are subject to costs being incurred to comply with carbon taxes, GHG emission reduction requirements, including methane emission reductions, and to preform necessary monitoring, measurement, verification and reporting of GHG emissions.

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, 2022, Crescent Point owned approximately 13,609 gross (11,367 net) producing and non-producing, abandoned wells for which abandonment and/or reclamation costs are expected to be incurred. During 2022, Crescent Point spent approximately $43.1 million on well abandonment and environmental reclamation activities, of which $23.0 million was received from government grant programs. In 2023, Crescent Point expects to carry out abandonment and reclamation operations that will total approximately $41.6 million, including amounts expected to be received from government programs. Crescent Point has estimated the net present value (discounted at approximately 3.28% per annum) of its total decommissioning liability (wells and facilities) to be approximately $703.9 million as at December 31, 2022, including liabilities associated with assets held for sale, based on estimated undiscounted and uninflated cash flows of approximately $931.8 million.

On July 30, 2020, the Government of Alberta announced a new liability management program that overhauls and modernizes the previous liability management program, known as the Liability Management Ratio (**"LMR"**) which uses a licensee's ratio of deemed asset value to deemed liability value to determine the risk that the licensee poses to the Orphan Well Association and to determine if a security deposit is required to mitigate that risk. The LMR was replaced by Directive 088: Licensee Life-Cycle Management ("**LLCM**"), which directive was released and became effective on December 1, 2021. Unlike the LMR, which measures two metrics to determine a licensee's risk, the LLCM assesses more than 30 additional metrics, such as the licensee's financial capability, previous closure activity, operational performance and regulatory compliance. Additionally, the new liability framework includes an Inactive Inventory Reduction Program which introduced annual mandatory liability reduction spending targets for each licensee. The new framework also includes the development of a program to address legacy sites that were abandoned, remediated or reclaimed before current requirements were introduced. In September 2022, the AER introduced the Closure Nomination Program as part of LLCM. This program allows for specific, direct stakeholders to nominate inactive sites for abandonment and/or reclamation.

Like the Alberta Government, the Government of Saskatchewan also announced enhancements to its Liability Management Program framework in 2020. This framework includes using licensee-specific data to better reflect the actual deemed asset and liability values, which is expected to improve the accuracy of License Liability Ratings; an Inactive Liability Reduction Program that requires an annual spending target on closure activities; completing the Proportional Risk Transfer model that will assess security deposit requirements for license transfers with a high amount of inactive infrastructure; and addressing regulatory gaps related to new entrants and the acceptable forms of security deposits. To support these new initiatives, the Government of Saskatchewan has enacted *The Financial Security and Site Closure Regulation*, which came into force on January 1, 2023.

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 McDaniel. 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
- 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 return of capital (which, for purposes of this AIF, includes dividends and share repurchases) to Shareholders.

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, state and local 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 our return of capital 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 our return of capital 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 return of capital 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.

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.

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

An increase in 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.

Current and future inflationary effects may be driven by, among other things, supply chain disruptions and governmental stimulus or fiscal policies, and geopolitical instability, including the ongoing conflict between the Ukraine and Russia. Continuing increases in inflation could increase our costs of labor and other costs related to our business, which could have an adverse impact on our business, financial position, results of operations and cash flows.

Higher operating and capital costs for our underlying properties will directly decrease the amount of cash flow received by the Corporation and, therefore, may reduce return of capital to our Shareholders.

The COVID-19 pandemic has adversely affected and could continue to adversely affect the Corporation's financial condition, operations and results from operations.

The COVID-19 pandemic, and initial actions taken in response, resulted in a significant contraction in the global economy. This caused a period of unprecedented disruption in the oil and gas industry and negatively impacted the demand for, and pricing of, energy products, including crude oil, NGLs and natural gas produced by the Corporation. A consequence of this disruption is that the oil and gas industry experienced a period of market contraction. Furthermore, the oil and gas industry experienced an increased risk of counterparty bankruptcy and insolvency. Although the pricing of energy products has returned to historical norms, volatility persists and disruptions to the oil and gas industry related to the pandemic could be severe.

In response to the COVID-19 pandemic, the Corporation implemented additional health and safety protocols within its Calgary office and field operations and continues to make adjustments to its health and safety protocols as required.

There are many variables and uncertainties that still remain regarding COVID-19, as well as its continued impact on the economic environment, including the duration of any further disruption to the oil and gas industry. During the COVID-19 pandemic, inflation has been driven by many factors, including disruptions to local and global supply chain and transportation services. Additionally, COVID-19 and its variants have the potential to directly affect the health of our employees. Inflation, disruptions to supply chain and transportation services and employee health have the potential to disrupt or impact the Corporation’s operations, projects and financial condition. The extent of the impact of COVID-19 on our operational and financial performance will depend on future developments, including the reemergence of widespread COVID-19 infections, COVID-19 variants, the pandemic's severity, government actions to contain the disease or mitigate its impact and the effectiveness of treatments and vaccines, all of which are highly uncertain and cannot be predicted with certainty at this time. Although government response measures to COVID-19 have generally relaxed, the ultimate impact of the pandemic is uncertain and subject to change. Other risks disclosed in this Annual Information Form may be heightened and there may also be effects that are not currently known.

The conflict in Ukraine and related price volatility and geopolitical instability could negatively impact our business.

In late February 2022, Russia launched significant military action against Ukraine. The conflict has caused, and could intensify, volatility in natural gas, oil and NGL prices, and the extent and duration of the military action, sanctions and resulting market disruptions could be significant and could potentially have a substantial negative impact on the global economy and/or our business for an unknown period of time. There is evidence that the increase in crude oil prices during the calendar year 2022 was partially due to the impact of the conflict between Russia and Ukraine on the global commodity and financial markets, and in response to economic and trade sanctions that certain countries have imposed on Russia. Any such volatility and disruptions may also magnify the impact of other risks described in this "Risk Factors" section.

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 return of capital 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, 2022, approximately 5% 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 return of capital 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;
- extreme weather events, including severe cold, wildfires and floods, which may damage or destroy infrastructure;
- blowouts or other accidents;
- public health crises, epidemics or pandemics, including the effects of, and response to, COVID-19;
- blockades and social unrest;
- accounting delays;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties;
- the establishment by the operator of reserves for these expenses; or
- delays in receiving government approvals and licenses.

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

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 and manages its exposures through a formal Risk Management and Counterparty Credit Policy, 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 return of capital 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 and our return of capital to Shareholders.

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 have a material adverse effect on the Corporation's operations and financial condition.

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 return of capital to Shareholders may be materially reduced.

Dividends on the Corporation's Common Shares and Common Share repurchases 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, or to repurchase Common Shares will be reduced. Furthermore, the availability of net cash flow is dependent upon commodity prices which are variable. Hence, the timing and amount of capital expenditures and the variability of commodity prices, 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 or to repurchase Common Shares. Therefore, dividends or share buybacks may be reduced, or even eliminated, at times when significant capital or other expenditures are made, or when commodity prices vary.

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 or to repurchase Common Shares during those periods in which funds are so retained.

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.

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

The economic impact on us of claims of indigenous title or rights is unknown. Indigenous people have claimed indigenous 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. Protests that affect transportation and other infrastructure in Canada, 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.

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, return of capital to Shareholders may be reduced.

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 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 return of capital to Shareholders.

Our operations and expertise are currently deployed 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, both domestically and abroad;
- the level of consumer product demand;
- extreme weather events, such as severe cold, wildfires and floods;
- political conditions, social unrest, sanctions, hostilities or war in, or relating to, oil and natural gas producing regions, including the Middle East, Africa, Eastern Europe (including the conflict between Ukraine and 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 and quantity of foreign imports;
- actions of governmental authorities;
- 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;
- conservation and environmental protection efforts;
- the price, availability and acceptance of alternative energy sources;
- technological advances affecting energy usage and consumption and energy supply;
- speculation by investors in oil and natural gas;
- public health crises, epidemics or pandemics, including the impacts of and response to COVID-19;
- weather conditions;
- variations between product prices at sales points and applicable index prices; and
- overall domestic and worldwide 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 extremely difficult 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, meet our financial obligations or provide return of capital to shareholders through dividends or share repurchases.

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

There is a risk that interest rates will continue to increase in response to inflation in Canada and the United States. An increase in interest rates could result in a significant increase in the amount we pay to service debt, while rising inflation could cause us to incur additional expense and, either or both, could have an adverse effect on our financial condition, results of operations and future growth, potentially resulting in a decrease in a decrease in the return of capital 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 return of capital 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 decease 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 unfavorable 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 return of capital 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. Additionally, the insurance market changes over time and, in the future, we may not be able to purchase insurance for all of the risks that we are currently able to insure against.

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, the Alberta EPA, the British Columbia Energy Regulator, the British Columbia Ministry of Environment and Climate Change Strategy, the SMER, the Manitoba Ministry of Climate, Environment and Parks, Environment and Climate Change Canada, Health Canada, Transport Canada and the Department of Fisheries and Oceans , CER, and, in the U.S., the EPA, the BLM, U.S. Bureau of Indian Affairs and the NDIC. Additionally, the development or implementation of changes to land use activities, such as regional or subregional planning, may effect how we are able to use certain lands for oil and gas development. 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, license 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. For example, if the Corporation did not qualify in 2022 for an exemption under the TIERS and OBPS programs in Alberta and Saskatchewan, respectively, the additional carbon compliance costs to the Corporation in Canada would have been, approximately, $13.7 million in 2022, which amount is calculated based on Scope 1 fuel combustion at the applicable 2022 carbon pricing rate.

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, including the impacts of climate change, 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 budget and, if required, out of cash flow and, therefore, will reduce the amounts available for return of capital 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 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 climate change legislation and regulations has increased operating costs as we pay fuel charges imposed by such legislation and have undertaken initiatives to reduce GHG emissions. Additionally, complying with methane reduction regulations applicable to our business requires Crescent Point to incur additional operating costs in order to achieve compliance.

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. Furthermore, 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. Additionally, changes in technology could decrease the demand for our products.

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, many 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, including severe cold, wildfires and floods, which can result in damage to or destruction of infrastructure, facilities and equipment. 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.

We may be unable to meet emissions targets.

We have set internal emissions reduction targets with respect to GHG emissions. There are substantial costs and operational changes required to meet such targets, and as such, we may be unable to finance the required changes to meet our emissions targets due to lack of capital for a variety of reasons, many of which are beyond our control.

Additionally, we may be unable to adequately alter our operations in such a way as to meet our emissions targets by the stated dates or at all.

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

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

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. Additionally, hydraulic fracturing has been found to induce seismicity, and the AER has developed monitoring and reporting requirements that companies must follow in certain areas of Alberta, and in certain cases, the AER may require that operations resulting in increased seismic activity be suspended and not resumed without AER approval. 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.

Our business and financial performance may be adversely affected by subsequent unavailability and unfavorable terms of water licenses.

Crescent Point utilizes fresh water in certain operations, including hydraulic fracturing operations, which water is obtained under licenses issued within each respective jurisdiction's regulations. If water use fees increase or a change under these licenses reduces the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licenses to withdraw water will not be rescinded, that additional conditions will not be added to these licenses or that the water licensed will be available. There is no assurance that if we require licenses or amendments to existing licenses, that these licenses or amendments will be granted on favorable terms. This may adversely affect our business, including the ability to operate our assets and execute development plans.

The Corporation's risk and/or cost of borrowing may be adversely affected by the 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 courts to hold that receivers and trustees can no longer avoid the AER legislated authority to: impose abandonment orders against licensees, or 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 may first be used to satisfy outstanding abandonment and reclamation 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 Redwater decision, the provincial regulation of environmental liabilities and associated decommissioning liability in the oil and gas industry is undergoing changes. The SMER announced that changes will be made to how it assesses the financial ability of operators/licensees to meet their abandonment, reclamation and other regulatory obligations and on December 1, 2021, the AER brought into force the new LLCM. The impact of any such regulatory measures by a provincial or federal government 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 additional rules to address the safety risks of transporting crude oil by rail.

In Canada, amendments have been made to the *Transportation of Dangerous Goods Regulations* 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 favorable 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 return of capital 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 return capital 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.

We may be adversely affected by extreme weather events.

Extreme weather events are an unpredictable risk. Wildfires can be caused by lightning, high temperatures, or by human activity and can spread because of wind and are otherwise encouraged by hot dry conditions. Floods can be caused by a high level of precipitation in a short period of time. Severe cold can cause water to freeze and expand leading to a chance that pipes can burst and valves may break. Wildfires, floods and severe cold can cause damage to or destroy infrastructure including roads, rail lines, and power transmission lines, cause damage to facilities and equipment, cause operational difficulties and access restrictions, lead to reduced operations or a cessation of operations in affected areas, and can cause supply chain disruptions affecting both our ability to market oil and gas and our ability to obtain goods and services required for our operations. Extreme weather events could adversely affect our business and operations, however, due to the unpredictable nature of extreme weather events, it is not possible to determine how or to what extent our business or operations may be affected.

We may be subject to environmental non-governmental organization legal challenges.

Environmental non-governmental organizations have become more aggressive in pursuing legal challenges to oil and gas companies, drilling and pipeline projects. In turn, this could result in increased costs and additional operating restrictions or delays as well as the risks under "*Risks Relating to Our Business - We may be Subject to Litigation.*"

Investor sentiment towards fossil fuel development may not align with our business.

Investor sentiment towards fossil fuel development has been affected by a number of factors, including public perception, climate change, environmental impacts of operations, environmental damage resulting from accidental releases, responsibility for orphaned wells and Indigenous rights. As a result of these and other concerns, some institutional, retail and governmental investors have announced that they will no longer fund or invest in oil and natural gas, or are reducing their investments in the same. Some institutional investors are also requesting that issuers develop and implement robust social, environmental and governance policies and practices, which may be more stringent than those which Crescent Point already has in place. Changing investor sentiment can make capital harder to access or more expensive, and may also have an effect on the value of our assets. It is not expected that changing investor sentiment will affect our operations in a manner materially different than they would affect other oil and gas entities of similar size.

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.

Shareholders who are non-residents of Canada may be subject to additional taxation.

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.

Shareholders who are non-residents of Canada may be subject to foreign exchange risk.

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 15th day of the month prior to the payment date.

Additionally, as part of its return of capital framework that targets the return of up to 50% of the Corporation's discretionary excess cash flow, the Corporation may declare special dividends. The first of such special dividends was paid on November 14, 2022, in the amount of $0.035 per Share.

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, debt and working capital levels, 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 and share repurchases are not permitted if the Corporation is in default under the agreements or the payment of such distribution would cause an event of default.

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

			Dividends per Common Share ($)
January 2020	–	December 2020	0.0175
January 2021	–	December 2021	0.0825
January 2022	–	December 2022	0.3600

Normal Course Issuer Bid

On March 9, 2021, Crescent Point commenced the 2021 NCIB to purchase, for cancellation, up to 26,462,509 Common Shares, representing 5% of the Corporation's public float as at February 26, 2021. The 2021 NCIB expired on March 8, 2022. A total of 8,602,500 Common Shares were purchased for cancellation under the 2021 NCIB.

On March 9, 2022, Crescent Point commenced the 2022 NCIB to purchase, for cancellation, up to 57,309,975 Common Shares, representing 10% of the Corporation's public float as at February 28, 2022. The 2022 NCIB is due to expire on March 8, 2023. In 2022, the Corporation purchased 25,561,600 Common Shares under the 2022 NCIB. As of February 20, 2023, the Corporation had purchased an additional 2,526,900 Common Shares under the 2022 NCIB in 2023.

The objective of the 2021 NCIB and the 2022 NCIB was to return capital to Shareholders in a way that is accretive to both Shareholders and the Corporation. Purchases of Common Shares under the 2022 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.

TSX	**High ($)**	**Low ($)**	**Volume (000's)**
2022			
January	8.57	7.08	133,375
February	9.15	7.78	106,162
March	10.08	7.87	148,580
April	10.05	8.09	103,824
May	11.59	8.18	141,197
June	13.74	8.69	187,316
July	10.25	7.87	111,614
August	10.85	8.56	105,555
September	10.00	7.57	106,038
October	11.14	8.91	94,437
November	11.54	9.96	82,037
December	10.65	8.83	84,977
2023			
January	10.22	8.64	77,066
February 1 - 20	10.09	9.13	61,302

NYSE	**High (US$)**	**Low (US$)**	**Volume (000's)**
2022			
January	6.85	5.38	151,331
February	7.23	6.12	140,904
March	7.87	6.13	228,224
April	7.98	6.33	176,065
May	9.15	6.27	250,061
June	10.96	6.68	369,861
July	8.00	6.02	269,912
August	8.35	6.60	267,511
September	7.63	5.51	263,675
October	8.25	6.49	326,524
November	8.61	7.38	177,460
December	7.94	6.46	131,835
2023			
January	7.67	6.39	103,313
February 1 - 20	7.57	6.77	89,257

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: Mike Jackson (Chair), Ted Goldthorpe, Francois Langlois and Mindy Wight each of whom is considered "independent" and "financially literate" within the meaning of National 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 chairs, 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. Additionally, the Audit Committee reviews the cyber risks facing the Corporation and any related policies for managing cyber risk, as well as the Corporation's enterprise risk management policy, processes and framework and the assessment of enterprise risk management effectiveness by internal audit.

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 Mandate is 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
Ted Goldthorpe	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 & 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 and has been serving as the CEO and Board Chair of Mount Logan Capital Inc, Portman Ridge Finance Corporation and Logan Ridge Financial Corporation and serves as President and CEO and Chair of Board of trustees of the Alternative Credit income Fund and Opportunistic Credit Interval Fund. Mr. Goldthorpe also serves as Lead Director of KITS Eyewear Board, to which he was appointed to in January 2021. 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 on the Board for Canadian Olympic Foundation, and serves on the Board of Directors for Her Justice and Capitalize for Kids.
Mike Jackson	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 & Investment Banking group focused on the oil & gas industry, including ten years heading the group. For the period 2006-2016, Mr. Jackson served as Financial Advisor to Boards/companies on M&A transactions aggregating over $28 billion. Mr. Jackson joined the Board of Crescent Point in November 2016. 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.
François Langlois	Mr. Langlois is an oil and gas executive who brings over 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) and the ICD.D designation granted by the Institute of Corporate Directors.
Mindy Wight	Ms. Mindy Wight brings over 15 years of tax and financial expertise in her current role of Chief Executive Officer for the Nch'kay Development Corporation, as well as holding the role as Treasurer of the Board of Directors. Prior to joining Nch'kay Development Corporation in November 2021, Ms. Wight held progressive tax roles at MNP LLP from 2016 to 2021 and most recently was a partner and National Leader of Indigenous Tax Services for the firm. Ms. Wight has also worked for two of the Big Four National accounting firms, the Chartered Accounting School of Business and the Canada Revenue Agency since graduating from the University of Northern British Columbia with a Bachelor of Commerce Degree, Accounting in 2007. Ms. Wight also possesses Chartered Professional Accountant, Chartered Accountant, and Certified Aboriginal Financial Manager designations. Ms. Wight has historically held Board positions as the Chair of the Board of Directors and Chair of the Finance and Audit Committee for the Nch'kay Development Corporation and was an Advisory Committee Member of the Budget and Financial Committee to the Squamish Nation.

External Auditor Services Fees

For services provided to the Corporation and its subsidiaries the years ended December 31, 2022 and 2021 PricewaterhouseCoopers LLP billed approximately $998,961 and $1,297,269, respectively, as detailed below:

	Year ended December 31	
	2022	2021
PricewaterhouseCoopers		
Audit fees	$ 952,778	$ 1,139,100
Audit-related fees	$ 46,183	$ 158,169
Tax fees	—	—
All other fees	$ —	$ —
Total	$ 998,961	$ 1,297,269

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 1, 2023 in respect of the Corporation's consolidated financial statements as at December 31, 2022 and December 31, 2021 and the Corporation's internal control over financial reporting as at December 31, 2022. 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 SEC.

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

ADDITIONAL INFORMATION

Additional financial information is available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov/edgar and on our website at 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 May 19, 2022, which is available on SEDAR. Additional financial information is provided in our comparative consolidated financial statements for our most recently completed financial year ended December 31, 2022 and MD&A.

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

CRESCENT POINT ENERGY CORP.

AUDIT COMMITTEE MANDATE

CORPORATE POLICIES & PROCEDURES

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 as 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 requirement 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 management's discussion and analysis, and the Corporation's 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;

(ii) the internal financial controls are regularly assessed for effectiveness and efficiency;

(iii) the Corporation's accounting functions are performed in a manner sufficient to ensure the Corporation has established and continues to maintain disclosure controls and procedures and internal control over financial reporting that meet the requirements of applicable laws, rules and regulations and allows the Chief Executive Officer and the Chief Financial Officer to certify the same;

(iv) the Corporation's quarterly and annual consolidated financial statements are properly prepared by management to comply with IFRS; and

(v) 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: (i) 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; (ii) the Corporation's supply chain management process and procedures; (iii) the Corporation's enterprise risk management policy and framework; and (iv) 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 (the "Members") from among the directors of the Corporation.

(b) Each Member must be an independent, non-executive director, free from any relationship that would interfere with the exercise of the Member's independent judgement. Members shall meet the independence and experience requirements of the regulatory bodies to which the Corporation is subject. Each Member shall have a basic understanding of finance and accounting and be able to read and understand fundamental financial statements at the time of the Member's appointment to the Committee. At least one Member shall have accounting or related financial management expertise and qualify as a "financial expert" or similar designation in accordance with the requirements of the regulatory bodies to which the Corporation is subject.

(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, and the rules, if any, adopted by the U.S. Securities and Exchange Commission 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 *ex officio* member of the Committee and shall be entitled to attend all meetings of the Committee.

(h) In the event of either: (i) a vacancy arising in the Committee that reduces the size of the Committee to fewer than three members; or (ii) the loss of independence of any Member, the Committee will fill the vacancy or replace the Member that has lost independence, as applicable, 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 the Member 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 this Mandate, 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 this Mandate 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 MANDATE

This Mandate outlines 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 Chairs, 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 this Mandate. 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 requirements of this Mandate.

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 this Mandate 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 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 the Associate General Counsel or other person authorized by the Corporate Secretary and acceptable to the Chair of the Committee) 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, the Senior Vice President, Finance and the internal audit 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 with management its assessment of the cyber risks facing the Corporation and any related policies and any proposed changes thereto for managing cyber risk;

(c) Annually review the enterprise risk management policy, processes and framework and the assessment of enterprise risk management effectiveness by internal audit;

(d) 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;

(e) Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

(f) Review the adequacy of insurance coverages maintained by the Corporation; and

(g) 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, the Senior Vice President Finance 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 and by third parties, regarding accounting, internal accounting controls, auditing or other 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, auditing matters and other matters;

(b) Copies of all complaints will be sent to the Chair of the Committee and to the Chair of the Board and to the Chair of those other committees of the Board responsible for the oversight of the subject matter of the complaint;

(c) Copies of complaints relating to accounting, internal accounting controls and auditing matters received will be sent to the Members of the Committee;

(d) 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

(e) 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

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.

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.

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.

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.

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 *ex officio* 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 such member's successor is appointed, unless such member resigns or is removed by the Board or such member 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 such member's position on the Committee on the earliest of (i) the appointment of such member's 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.

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.

SECRETARY

The Corporate Secretary of the Corporation, the Associate General Counsel 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.

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:

(1) 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.

(2) 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.

(3) 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.

(4) Every question at a Committee meeting shall be decided by a majority of the votes cast.

(5) 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.

(6) 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.

(7) 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.

NOTICE OF MEETING

Notice of the time and place of each meeting may be given in writing, by electronic means, or orally 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.

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, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2022, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel	December 31, 2022	Canada	—	10,740,688	—	10,740,688
McDaniel	December 31, 2022	United States	—	1,719,075	—	1,719,075
		Total	**—**	**12,459,763**	**—**	**12,459,763**

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.

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

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd.

ORIGINALLY SIGNED BY

Michael J. Verney, P.Eng.
Executive Vice President

Calgary, Alberta, Canada
February 7, 2023

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.

McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator, has 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 evaluator;

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

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

The Reserves Committee 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"	*"Ryan Gritzfeldt"*
CRAIG BRYKSA President and Chief Executive Officer	RYAN GRITZFELDT Chief Operating Officer
"Francois Langlois"	*"Barbara Munroe"*
FRANCOIS LANGLOIS Director	BARBARA MUNROE Chair of the Board

March 1, 2023