crew energy inc.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2019

March 26, 2020

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
Mmbbl	million barrels
bbl/d	barrels per day
BOPD	barrels of oil per day
NGL or ngl(1)	natural gas liquids
Mcf	thousand cubic feet

Natural Gas

Mcfe	thousand cubic feet equivalent
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
Mmbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	Gigajoule
Tcf	trillion cubic feet

Note:

(1) Except where specified otherwise in this AIF, NGL as defined in the COGE Handbook includes those hydrocarbon components that can recovered from natural gas as liquids, including but not limited to ethane, propane, butane, pentanes plus, condensate, and small quantities of non-hydrocarbons.

Other

AECO	the natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE or boe	barrel of oil equivalent on the basis of 6 Mcf/BOE for natural gas and 1 bbl/BOE for crude oil and natural gas liquids
BOE/d or Boe/d	barrel of oil equivalent per day
CSA	Canadian Securities Administrators
m^3	cubic metres
Mboe	1,000 barrels of oil equivalent
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Measurements expressed in Boe or Mcfe may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl and an Mcfe conversion ratio of 1 bbl:6 Mcf are based on an approximate energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Where any disclosure of reserves data is made in this Annual Information Form that does not reflect all reserves of Crew Energy Inc. ("Crew" or the "Corporation"), the reader should note that the estimates of reserves and future net revenue for individual properties or groups of 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.

CONVERSIONS

To Convert From:	To:	Multiply By:
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
bbl	Cubic metres	0.159
Cubic metres	bbl oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. In addition, there are forward-looking statements in this Annual Information Form under the heading: "Statement of Reserves Data and Other Oil and Gas Information" as to our reserves and future net revenues from our reserves, pricing and inflation rates and future development costs, as to the development of our proved undeveloped reserves and probable undeveloped reserves, as to our future development activities, forward contracts and transportation commitments, hedging policies, abandonment and reclamation costs, tax horizon, exploration and development activities and production estimates. In addition to the forward-looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the anticipated completion of our Midstream Transactions and the anticipated benefits to be derived therefrom. These 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. The Corporation 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 included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In addition to the forward-looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the performance characteristics of our oil, NGL and natural gas properties; oil, NGL and natural gas production levels; the size of the oil, NGL and natural gas reserves; projections of market prices and costs; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; treatment under governmental regulatory regimes and tax laws; impacts of current commodity prices on the Corporation; budget expectations and 2020 capital expenditure programs which remain subject to ongoing review and potential change.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. In addition, these risks and uncertainties are material factors affecting the success of our business. Such factors include, but are not limited to: declines in oil, NGL and natural gas prices; various pipeline constraints; variations in interest rates and foreign exchange rates; stock market volatility; uncertainties relating to market valuations; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our hedging activities; third party credit risk; risks associated with the exploitation of our properties and our ability to acquire reserves; government regulation and control and changes in governmental legislation; changes in income tax laws, royalty rates and other incentive programs; uncertainties associated with estimating oil, NGL and natural gas reserves and resources; risks associated with acquiring, developing and exploring for oil, NGL and natural gas and other aspects of our operations; our reliance on hydraulic fracturing; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions, including risks associated with the anticipated completion of our Midstream Transactions, and dispositions or to manage growth; changes in climate change laws and other environmental regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling, completion and related equipment; risks of non-cash losses as a result of the application of accounting policies; our operating activities and ability to retain key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; risks for United States and other non-resident shareholders; risks described in further detail under "Risk Factors" herein; and other factors, many of which are beyond our control.

The actual results could differ materially from those results anticipated in these forward-looking statements, which are based on assumptions, including as to the market prices for oil, NGL and natural gas; the continuation of the present policies of the Board of Directors relating to management of Crew, capital expenditures and other matters; the continued availability of capital, acquisitions of reserves, undeveloped lands and skilled personnel; the continuation of the current tax and regulatory regime and other assumptions contained in this Annual Information Form.

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 and resources described can be profitably produced in the future.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Crew’s operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or on Crew’s website (www.crewenergy.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation’s general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserves reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta);

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook, Consolidated Third Edition, prepared by the Society of Petroleum Evaluation Engineers (Calgary chapter), as amended from time to time;

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

"**Condensate**" means a mixture of pentanes and heavier hydrocarbons recovered as a liquid at the inlet of a gas processing plant before the gas is processed and pentanes and heavier hydrocarbons obtained from the processing of raw natural gas.

"**Credit Facility**" has the meaning ascribed thereto under the heading "*Description of Capital Structure – Credit Facility*";

"**Crew**" or the "**Corporation**" means Crew Energy Inc., a corporation amalgamated pursuant to the ABCA and includes its predecessors where the context so requires;

"**Crew Energy Partnership**" means Crew Energy Partnership, a general partnership formed under the laws of Alberta, the partners of which are Crew and Crew Oil & Gas;

"**Crew Heavy Oil Partnership**" means Crew Heavy Oil Partnership, a general partnership formed under the laws of Alberta, the partners of which are Crew and Crew Oil & Gas;

"**Crew Oil & Gas**" means Crew Oil & Gas Inc., a corporation amalgamated under the ABCA;

"**Gross**" or "**gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "company gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**Midstream Transactions**" means the two strategic debt and cost reduction transactions with a third party midstream company announced by way of news release on January 17, 2020 as more particularly described under the heading "*Description and General Development of the Business – Recent Developments*".

"**Net**" or "**net**" means:

(a) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(c) 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.

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

"**Sproule**" means Sproule Associates Limited;

"**Sproule Report**" means the report of Sproule dated January 30, 2020 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2019;

"**Subsidiary**" means, with respect to any Person, a subsidiary (as that term is defined in the ABCA (for such purposes, if such person is not a corporation, as if such person were a corporation)) of such Person and includes any partnership, joint venture, trust, limited liability company, unlimited liability company or other entity, whether or not having legal status, that would constitute a subsidiary (as described above) if such entity were a corporation;

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

"**Ultra-Condensate Rich**" or "**UCR**" is not defined in NI 51-101 and means a fairway of land at Crew's Greater Septimus area of operations where productive zones have high condensate rates (initial 30-day condensate / gas ratio rates of greater than 75 bbls per mmcf);

"**2020 Notes**" means the Corporation's previously outstanding 8.375% senior unsecured notes described under the heading "*Description of Capital Structure – Senior Unsecured Notes*"; and

"**2024 Notes**" means the Corporation's currently outstanding 6.500% senior unsecured notes described under the heading "*Description of Capital Structure – Senior Unsecured Notes*".

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2019.

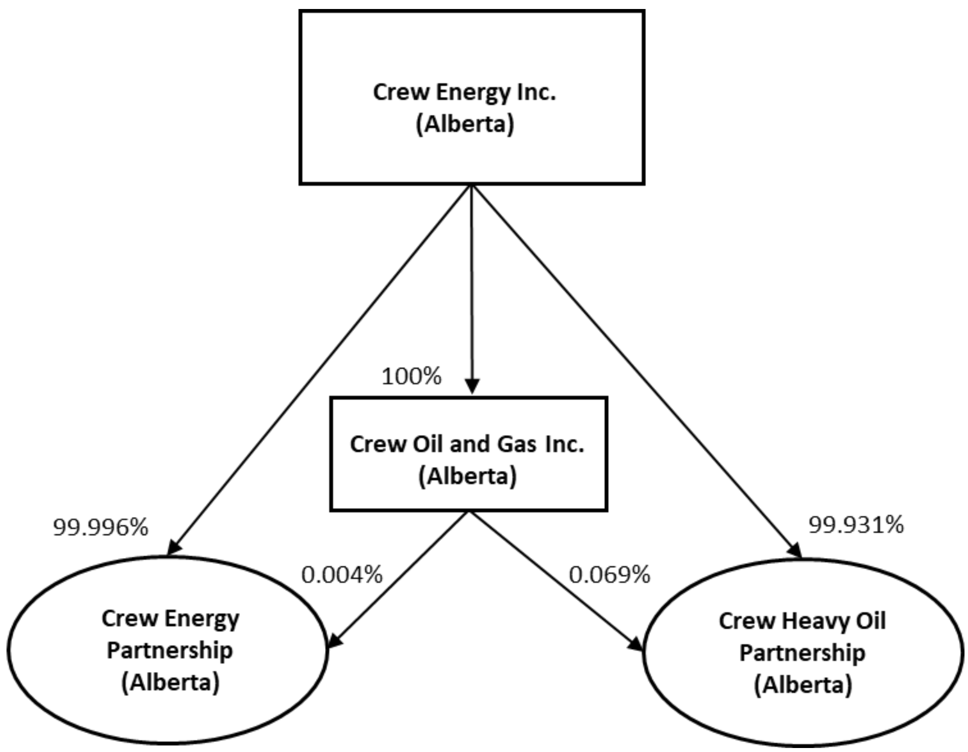
All dollar amounts herein are in Canadian dollars, unless otherwise stated.

CORPORATE STRUCTURE

Crew was originally incorporated pursuant to the provisions of the ABCA as 1046546 Alberta Ltd. On May 12, 2003. On June 27, 2003, Crew filed Articles of Amendment to change its name to “Crew Energy Inc.”

On December 31, 2011 Crew completed a short form amalgamation under the ABCA with its then wholly-owned subsidiaries, Crew Resources Inc. and Caltex Energy Inc. to form “Crew Energy Inc.”

The following diagram describes the inter-corporate relationships among Crew and its material Subsidiaries as at December 31, 2019.



Crew’s head office is located at Suite 800, 250 – 5th Street S.W., Calgary, Alberta, T2P 0R4 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

The Common Shares of Crew trade on the TSX under the symbol “CR”.

Unless the context otherwise requires, reference herein to “Crew” or the “Corporation” means Crew Energy Inc. together with its Subsidiaries.

DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS

Business Plan and Growth Strategies

The Crew business plan is to create sustainable and profitable growth in the oil and gas industry in western Canada, while remaining sufficiently flexible to adapt to changing industry conditions. Crew is specifically focused on the development of assets within the Montney resource play in northeast British Columbia. The following are integral components of Crew's corporate strategy:

- Crew adheres to safe and environmentally responsible operations while remaining committed to sound environmental, social and governance ("ESG") practices which underpin the Company's fundamental business tenets;
- Focus on identifying, acquiring and exploiting large hydrocarbon reservoirs by applying proven and evolving technologies;
- Utilize an annual short and long-range planning process with its Board of Directors assessing performance and setting future direction;
- Develop a long-range transportation and marketing plan to ensure access to market and diversified pricing exposure, where possible, for the Corporation's oil, natural gas and NGL production;
- Create and maintain a significant inventory of drilling locations that is refreshed on an annual basis and allows the Corporation to allocate capital on a risked rate-of-return basis;
- Crew actively manages its portfolio of assets to take advantage of value-enhancing acquisitions and dispositions when market conditions permit;
- Crew monitors its capital structure with a focus on maintaining a strong financial position. This is achieved with regular adjustments to capital spending, hedging of future revenue and costs where possible, the issuance of new equity, issuance of new debt or repayment of existing debt with the proceeds of non-core asset dispositions; and
- Crew values and maintains an entrepreneurial culture to attract and retain high-quality staff.

To achieve sustainable and profitable growth, management of Crew believes in controlling the timing and costs of its projects by maintaining operatorship of those projects wherever possible. To minimize competition within its geographic areas of interest, Crew strives to maximize its working interest ownership in its properties where reasonably possible. In reviewing potential drilling or acquisition opportunities, Crew gives consideration to the following criteria: (i) the at-risk capital required to secure or evaluate the investment opportunity; (ii) if successful, the potential return on the project; (iii) the likelihood of success; (iv) the risked return versus cost of capital; (v) the strategic benefits to Crew; and (iv) Crew's technical expertise in the opportunity. Crew also employs a strategy of reducing operating risk and costs by controlling and operating a significant portion of its infrastructure, including pipelines and gas plants in its core operating areas. While Crew believes that it has the skills and resources necessary to achieve its objectives, participation in the exploration and development of oil and natural gas has a number of inherent risks. See "*Risk Factors*".

In general, Crew uses a portfolio approach in developing a number of opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable levels of profitable production and financial growth. Crew's plan is to focus on growing the Corporation's production with a focus on development of its Montney condensate-rich natural gas assets in northeast British Columbia while maintaining a strong financial position. Crew's size and asset base allows for discretionary capital expenditures if play economics are impacted by low commodity prices or significant cost inflation. The Corporation continually monitors its financial position and has the ability to adjust capital spending, sell non-core assets or seek alternative forms of financing in order to maintain the Corporation's financial position.

Crew's management team has a demonstrated track record of bringing together the key components to a successful intermediate-sized exploration and production company including, but not limited to: strong technical skills, expertise in planning and financial controls, ability to execute on business development opportunities, commitment to ESG principles and an entrepreneurial spirit that enables Crew to effectively identify, evaluate and execute on value-added initiatives.

Crew has executed its strategy through exploration and development programs combined with both corporate and property acquisitions. Financing for these programs has been obtained through a combination of cash flow from existing operations, property dispositions, long-term debt in the form of bank facilities and senior unsecured notes and historical equity issues of common shares.

Crew may pursue asset or corporate acquisitions, divestitures or investments that do not conform to the guidelines discussed above based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

Corporate History

The following is a description of significant events over the last number of completed financial years that have influenced the general development of the Corporation's business.

Crew has been engaged in the business of exploring for, developing, producing and acquiring crude oil, NGL and natural gas in western Canada since it began active operations in 2003.

In May 2008, the Corporation completed the acquisition of Crown leasehold interests in approximately 102.2 net sections of undeveloped Montney formation rights located in the Corporation's core operating area in northeast British Columbia for approximately $63 million. During the period December 2012 through July 2013, Crew completed the acquisition of approximately 200 additional net sections of liquids-rich Montney rights contiguous or proximal to Crew's existing Montney lands in northeast British Columbia for aggregate cash consideration of approximately $77.2 million.

In the first quarter of 2014, Crew completed two separate transactions that resulted in the Corporation acquiring additional strategic Montney liquids-rich natural gas properties in northeast British Columbia for approximately $105 million. The acquired assets comprised 75 net sections of land either contiguous with existing Crew land or increasing Crew's working interest in joint interest lands. Pursuant to these transactions, the Corporation acquired approximately 1,400 boe/d of associated production (98% natural gas), along with under-utilized strategic infrastructure consisting of 130 kilometres of pipeline and over 6,200 horsepower of field compression. The Corporation also purchased an additional 40 net sections of strategic Montney rights in the third quarter of 2014 for approximately $17.1 million.

In July 2015, the Corporation completed a petroleum and natural gas rights exchange with the province of British Columbia, adding 53 net sections of new Montney land contiguous to the Corporation's Groundbirch property in exchange for surrendering 66 net sections of undeveloped land that had been subject to restricted development since 2004. The Corporation's firm transportation arrangement on the Alliance pipeline system became effective on December 1, 2015, securing 100 Mmcf per day of zone 2 firm receipt service and 25 Mmcf per day of zone 2 priority interruptible service that provides takeaway capacity to alternative markets, enabling the Corporation to capture more favorable pricing.

Throughout 2016, the Corporation continued to demonstrate the success of its Montney focused strategy with positive growth across its core Greater Septimus area, and advancement of its future development plans at Groundbirch. While commodity prices remained very weak through the first half of 2016, the Corporation benefited from lower costs and improved operational efficiencies and had access to required drilling and completion services. The Corporation also reported strong Montney reserves growth with attractive capital efficiencies.

Field activity in 2017 was focused at the Greater Septimus area, where Crew continued to delineate the ultra liquids-rich resource at West Septimus and completed a facility expansion to 120 Mmcf per day. In aggregate, Crew's capital expenditures totaled $238 million in 2017. The Corporation drilled 35 (33.2 net) wells, increasing reserves per share by approximately 28% on a proved developed producing basis, 9% on a total proved basis and 12% on a total proved plus probable basis. Production volumes averaged 23,061 boe per day in 2017.

The Corporation improved its financial flexibility in 2017 and provided the financing needed for the 2017 growth of its liquids-rich Montney strategy. In March, Crew completed the issuance of $300 million aggregate principal amount of 6.5% senior unsecured notes due March 14, 2024 pursuant to a private placement offering. In conjunction therewith, Crew completed the redemption of its previously outstanding 8.375% senior unsecured notes. See "*Description of Capital Structure – Senior Unsecured Notes*". During the second quarter of 2017 Crew completed the disposition of 18,400 net acres of undeveloped Montney land in the Goose area of northeast British Columbia for $49 million. The assets disposed of included no production or assigned reserves.

The Corporation's 2018 capital expenditures totaled $93.4 million contributing to annual average production of 23,885 Boe per day, a 4% increase over 2017. Development opportunities in the higher-value Ultra-Condensate Rich ("UCR") area at West Septimus were prioritized, and ten (10.0 net) wells were drilled and 14 (12.3 net) wells were completed in the area in 2018. Within the UCR area at West Septimus, shifting to longer lateral wells led to a 28% increase in total proved reserves and a 17% increase in proved plus probable reserves year-over-year. The Corporation also completed construction of a pipeline connecting its West Septimus facility to the existing TC Energy Saturn meter station which provides physical access to all three major natural gas egress systems transporting natural gas out of Western Canada.

Crew's 2019 net capital expenditures totaled $95.0 million (after a net $19.1 million of asset dispositions net of acquisitions) which contributed to annual average production of 22,837 Boe per day. Operational efficiencies continued to improve with Crew realizing a 26% reduction in per well costs through 2019 relative to previous pacesetter wells, on pads featuring wells with lateral lengths over 3,000m, the longest in Crew's history. In 2019, Crew continued its strategy of increasing condensate production year-over-year. In addition, non-core land sales that closed in 1H/19 resulted in gross proceeds of $21 million, which was applied to pay down outstanding bank debt. The Corporation's development focus continued to prioritize the drilling and completion of extended reach horizontal ("ERH") wells within the UCR area at West Septimus, with six (6.0 net) wells drilled and 12 (12.0 net) wells completed in the area, along with the recompletion of 26 (25.0 net) wells at Crew's Lloydminster heavy oil area.

Recent Developments

On January 17, 2020, Crew announced that it had entered into a strategic transaction with a third party midstream company for the disposition of a 22% net working interest in each of its Septimus gas processing facility and West Septimus gas processing facility located in northeast British Columbia for aggregate consideration of $70.0 million (the "**Midstream Transactions**"). The first closing of the Midstream Transactions was completed on February 27, 2020, whereby an 11% working interest was disposed of for $35 million, with proceeds applied to reduce borrowings on the Credit Facility. The sale of an additional 11% working interest for $35 million is expected to close in the fourth quarter of 2020, subject to satisfaction of certain customary closing conditions. In a separate transaction, Crew has elected to exercise its option to acquire an approximate 16% interest in the same two facilities for approximately $12 million in the fourth quarter of 2020. These transactions will enable the Corporation to strengthen the balance sheet, ultimately reducing net debt by $58.3 million with $2.1 million of annual cost savings.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Crew competes with numerous other participants in the search for, and the acquisition of, oil, NGL and natural gas properties and in the transportation and marketing of oil, NGL and natural gas. Crew's competitors include resource companies which have greater financial resources, staff and facilities than those of Crew. Competitive factors in the distribution and marketing of oil, NGL and natural gas include price along with the method, availability and reliability of delivery. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex. Crew will attempt to enhance its competitive position by operating in areas where its technical personnel are experienced and able to reduce some of the risks associated with exploration, production and marketing. Crew believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development. See "*Risk Factors – Competition*".

Commodity Prices

The Corporation's operational and financial results are dependent on the prices received for oil, NGL and natural gas production. Any substantial and extended decline in the price of oil, NGL and natural gas would have an adverse effect on, among other things, the Corporation’s revenues and financial condition. Commodity prices declined significantly in 2016 with continued volatility during 2017 through 2019 and into early 2020. See *“Risk Factors – Weakness in the Oil and Gas Industry”* and *“Risk Factors – Prices, Markets and Marketing”*.

SIGNIFICANT ACQUISITIONS

There were no significant acquisitions completed by Crew during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the “**Statement**”) is dated February 3, 2020. The effective date of the Statement is December 31, 2019 and the preparation date of the Statement was March 26, 2020. The Reserves Data conforms to the requirements of NI 51-101.

Disclosure of Reserves Data

The reserves data set forth below (the “**Reserves Data**”) is based upon an evaluation by Sproule with an effective date of December 31, 2019 and is contained in the Sproule Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs prior to the provision for interest, debt service charges, general and administrative expenses, the impact of hedging activities, and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Crew believes is important to the readers of this information. The Corporation engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation’s reserves are in Canada, specifically, in the provinces of British Columbia, Saskatchewan and Alberta.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by the Independent Qualified Reserves Evaluator in Form 51-101F2 are attached at Appendices A and B hereto, respectively.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of the Corporation’s crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2019

RESERVES SUMMARY

RESERVES CATEGORY	LIGHT CRUDE OIL & MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT CRUDE OIL & MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (Mmcf)	CONVENTIONAL NATURAL GAS Net (Mmcf)	TOTAL OIL EQUIVALENT Gross (Mboe)	TOTAL OIL EQUIVALENT Net (Mboe)
PROVED										
Developed Producing	315	291	1,070	985	13,141	10,988	291,587	248,072	63,122	53,610
Developed Non-Producing	0	0	856	747	195	174	5,098	4,646	1,901	1,695
Undeveloped	3,198	2,659	2,068	1,893	27,784	23,340	623,453	529,427	136,958	116,130
TOTAL PROVED	3,512	2,950	3,994	3,625	41,120	34,502	920,137	782,144	201,982	171,435
TOTAL PROBABLE	3,794	3,227	3,574	3,152	43,310	35,716	947,489	787,835	208,593	173,400
TOTAL PROVED PLUS PROBABLE	7,306	6,177	7,568	6,778	84,430	70,217	1,867,626	1,569,980	410,574	344,835

Note:

(1) Columns may not add due to rounding.

NET PRESENT VALUES OF FUTURE NET REVENUE[1]

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
PROVED										
Developed Producing	704,938	543,075	438,722	370,013	322,240	704,938	543,075	438,722	370,013	322,240
Developed Non-Producing	27,826	23,323	20,130	17,755	15,903	27,826	23,323	20,130	17,755	15,903
Undeveloped	1,983,005	1,081,723	653,409	423,237	286,736	1,531,497	865,802	537,317	355,509	244,822
TOTAL PROVED	2,715,768	1,648,121	1,112,261	811,005	624,879	2,264,260	1,432,200	996,169	743,277	582,965
TOTAL PROBABLE	4,343,823	1,829,803	956,345	579,980	390,500	3,163,004	1,331,367	696,405	425,907	291,377
TOTAL PROVED PLUS PROBABLE	7,059,591	3,477,924	2,068,605	1,390,985	1,015,379	5,427,264	2,763,567	1,692,574	1,169,184	874,342

Notes:

(1) Reflects estimated abandonment, decommissioning and reclamation ("ADR") costs associated with all of Crew's assets evaluated in the Sproule Report, including all active and inactive wells (producing, suspended and service), gathering systems, facilities and surface land development.

(2) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2019

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES[(2)] (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS[(1)] (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	6,838,874	813,986	2,295,646	845,382	168,091	2,715,768	451,508	2,264,260
Total Proved Plus Probable	15,358,142	1,908,209	4,373,346	1,787,165	229,831	7,059,591	1,632,327	5,427,264

Notes:

(1) Reflects estimated abandonment, decommissioning and reclamation ("ADR") costs associated with all of Crew's assets evaluated in the Sproule Report, including all active and inactive wells (producing, suspended and service), gathering systems, facilities and surface land development.
(2) Royalties include Saskatchewan Capital Surtax.

FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2019

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES[(3)] (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAXES[(4)] (discounted at 10%/year) (Units as noted)
Total Proved	Light Crude Oil and Medium Crude Oil[(1)]	18,347	5.17 per boe
	Heavy Crude Oil[(1)]	33,863	9.33 per boe
	Conventional Natural Gas[(2)]	1,060,051	1.08 per mcfe
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil[(1)]	51,432	5.29 per boe
	Heavy Crude Oil[(1)]	91,123	13.42 per boe
	Conventional Natural Gas[(2)]	1,926,050	0.98 per mcfe

Notes:

(1) Including solution gas and other associated by-products.
(2) Including associated by-products but excluding solution gas.
(3) Other company revenue and costs not related to specific production group have been allocated proportionately to production groups.
(4) Unit values are based on Net reserves.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and conventional natural gas reserves estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

   Reserves Categories

Reserves are the estimated remaining quantities of crude oil, natural gas, non-conventional natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;

- the use of established technology; and
- specified economic conditions which are generally accepted as reasonable.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **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.

(b) **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.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories.

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling and completing a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned and be expected to be developed within a limited time.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide 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.

Levels of Certainty for Reported Reserves

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

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

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A 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 clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast Prices and Costs

Sproule has prepared its December 31, 2019 price and market forecasts as summarized in the tables below after a comprehensive review of information. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant.

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, NGL and natural gas forecast pricing, as at December 31, 2019, inflation and exchange rates utilized by Sproule in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2019
FORECAST PRICES AND COSTS

	OIL			ALBERTA NGLS			NATURAL GAS				
Year	WTI Cushing @ Oklahoma ($US/bbl)	LIGHT, SWEET OIL @ Edmonton (40 ºAPI, 0.3% S) ($Cdn/bbl)	Western Canada Select (WCS) 20.5 ºAPI ($Cdn/bbl)	EDMONTON PROPANE ($Cdn/bbl)	EDMONTON BUTANE ($Cdn/bbl)	EDMONTON PENTANES PLUS ($Cdn/bbl)	AECO Gas Price ($Cdn/MmBtu)	Westcoast Station 2 Spot Gas Price ($Cdn/MmBtu)	CAPITAL INFLATION RATE %/Year	OPERATING INFLATION RATE(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast											
2020	61.00	73.84	59.81	25.07	37.72	76.32	2.04	1.54	0.0	0.0	0.760
2021	65.00	78.51	63.98	31.84	43.90	80.52	2.27	1.87	1.0	1.0	0.770
2022	67.00	78.73	63.77	32.43	47.74	80.00	2.81	2.41	2.0	2.0	0.800
2023	68.34	80.30	65.04	33.26	48.69	81.68	2.89	2.49	2.0	2.0	0.800
2024	69.71	81.91	66.34	34.12	49.67	83.38	2.98	2.58	2.0	2.0	0.800
2025	71.10	83.54	67.67	34.99	50.66	85.13	3.06	2.66	2.0	2.0	0.800
2026	72.52	85.21	69.02	35.88	51.67	86.90	3.15	2.75	2.0	2.0	0.800
2027	73.97	86.92	70.40	36.78	52.71	88.72	3.24	2.84	2.0	2.0	0.800
2028	75.45	88.66	71.81	37.71	53.76	90.57	3.33	2.93	2.0	2.0	0.800
2029	76.96	90.43	73.25	38.65	54.84	92.45	3.42	3.02	2.0	2.0	0.800
2030	78.50	92.24	74.71	39.61	55.93	94.38	3.51	3.11	2.0	2.0	0.800
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	2.0	0.800

Notes:

(1) Inflation rates for operating costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2019, were $2.53 per mcf for conventional natural gas, $63.24 per bbl for light/medium crude oil, $50.65 per bbl for heavy crude oil at Lloydminster, $64.40 per bbl for condensate, $6.78 per bbl for NGL excluding condensate and $39.45 per bbl for NGL including condensate.

4. Estimated well abandonment, decommissioning and reclamation ("ADR") costs associated with all of Crew's assets evaluated in the Sproule Report include all active and inactive wells (producing, suspended and service), gathering systems, facilities and surface land development.

5. The forecast price and cost assumptions assume the continuance of current laws and regulations.

6. The extent and character of all factual data supplied to Sproule were accepted by Sproule as represented. No field inspection was conducted.

7. The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis and utilizing the Corporation's tax pools. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

Reconciliation of Changes in Reserves

CURRENT YEAR RECONCILIATION OF GROSS(1) RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT CRUDE OIL & MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2018	1,811	9,089	10,900	4,731	3,941	8,672	35,696	45,342	81,038
Extensions & Improved(2) Recovery	-	-	-	-	69	69	3,419	6,289	9,708
Infill Drilling	-	-	-	65	43	108	-	-	-
Technical Revisions(3)	1,809	(5,283)	(3,473)	(136)	(426)	(562)	4,119	(8,504)	(4,385)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(1)	(0)	(1)	-	-	-	(8)	(4)	(11)
Economic Factors	(29)	(13)	(41)	(69)	(53)	(121)	(374)	187	(187)
Production	(79)	-	(79)	(598)	-	(598)	(1,733)	-	(1,733)
December 31, 2019	3,512	3,794	7,306	3,994	3,574	7,568	41,120	43,310	84,430

	CONVENTIONAL NATURAL GAS			OIL EQUIVALENT		
FACTORS	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved Plus Probable (Mmcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)
December 31, 2018	783,611	1,078,529	1,862,141	172,840	238,127	410,967
Extensions & Improved Recovery(2)	36,733	67,614	104,347	9,542	17,626	27,168
Infill Drilling	-	-	-	65	43	108
Technical Revisions(3)	145,930	(203,734)	(57,804)	30,114	(48,168)	(18,054)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(246)	(114)	(360)	(49)	(23)	(72)
Economic Factors	(10,341)	5,193	(5,148)	(2,195)	987	(1,208)
Production	(35,550)	-	(35,550)	(8,336)	-	(8,336)
December 31, 2019	920,137	947,488	1,867,626	201,982	208,593	410,574

Notes:

(1) Gross Reserves in the tables above mean the Corporation's working interest share before calculation of royalties and before consideration of the Corporation's royalty interests.

(2) Increases to Extensions & Improved Recovery are primarily the result of step-out locations drilled by Crew in West Septimus. Reserves additions for Extensions and Improved Recovery are combined and reported as "Extensions & Improved Recovery".
(3) Technical Revisions also include changes in reserves associated with changes in operating costs, capital costs and commodity price offsets.
(4) Columns may not add due to rounding.

Positive technical revisions in the Total Proved category for year end 2019 were predominantly the result of undeveloped locations moving from the Total Probable category into the Total Proved category. This was mainly due to offsetting development activity establishing commercial productivity within proximity which is consistent with COGEH guidance for assignment of Proved reserves. Proved reserves that are associated with stand-alone probable reserves booked in prior years were added to the evaluation this year as follows: 2,978 Mbbls of Light and Medium Oil, 126,883 Mmcf of Conventional Natural Gas and 3,981 Mbbls of Natural Gas Liquids. Several factors contributed to negative technical revisions on total Proved plus Probable reserves at year end 2019, including a minor reduction in NGL yield at Septimus and West Septimus, which declined from 38.5 bbls/Mmcf in 2018 to 36.0 bbls/Mmcf in 2019. Due to the increase in UCR wells in 2019, Crew realized changes to gas shrinkage rates at Septimus and West Septimus, which increased from 7.5% at year end 2018 to 9.0% in 2019. Finally, in the greater Tower area, 16 probable locations were removed from the Sproule Report as their development timeline was extended beyond the ten year development guideline as prescribed within the COGE Handbook. The delayed timing of this project was the result of it being moved down in priority relative to other projects with higher anticipated rates of return.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices prescribed by the COGE Handbook and as defined under NI 51-101.

The following tables set forth the proved undeveloped gross reserves and the probable undeveloped gross reserves, each by product type that were first attributed in each of the most recent three financial years. These reserves are included in the "Summary of Oil and Gas Reserves" table on page 6 of this AIF.

Proved Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (Mmcf)		NGLs (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2017	-	1,404	-	1,383	28,705	487,307	1,203	21,265
2018	-	1,379	736	2,119	19,606	497,023	1,959	24,122
2019	-	3,198	-	2,068	36,733	623,453	3,419	27,784

Sproule has assigned 136,958 Mboe of proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with approximately $835 million of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Sproule Report accounts for approximately $212 million or 25% of the total forecast.

Probable Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (Mmcf)		NGLs (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2017	-	10,561	-	2,212	218,239	793,766	12,394	34,026
2018	-	8,960	879	2,435	103,924	966,149	4,860	42,049
2019	-	3,726	69	2,410	67,614	873,851	6,289	40,069

Sproule has assigned 191,847 Mboe of probable undeveloped reserves in the Sproule Report and has allocated additional future development capital of approximately $940 million to all probable undeveloped reserves with 2% of the probable additional development capital forecast to be spent in the first two years.

As of December 31, 2019, undeveloped reserves represented 68% of total proved reserves and 80% of proved plus probable reserves. Close to 98% of the proved plus probable undeveloped reserves are located in the Corporation's Montney assets in northeast British Columbia and approximately 2% in its Lloydminster area of operations.

Reserves were assigned in the Sproule Report adhering to the practices outlined within the COGE Handbook, with uncertainty applied at the individual location level to account for the potential variability in well results. With respect to the Corporation's Lloydminster area of operations, proved undeveloped reserves are scheduled for development within three years and over the next five years in the case of probable undeveloped reserves. The Corporation's Montney assets in northeast British Columbia have been scheduled for development within five years in the case of proved undeveloped reserves and within ten years in the case of probable undeveloped reserves, with the exception of certain properties flowing through the Septimus/West Septimus gas processing facilities which have development scheduled to maintain the combined facility capacity for an extended time frame and which represent less than 28% of proved plus probable undeveloped locations. The total proved plus probable undeveloped volumes are all scheduled to produce within the capacity constraints of existing facilities.

The pace of development of the proved and probable undeveloped reserves (both in 2020 and 2021 as well as in years beyond 2021) is influenced by many factors. These factors may include the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations or changing regulation and/or fiscal policy); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion from a separate zone is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors – Exploration, Development and Production Risks*".

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently 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 at the effective date of the report, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

The Corporation has a significant amount of proved undeveloped and probable undeveloped reserves assigned to the Montney in Crew's northeast British Columbia geographic area of operations. Sophisticated and expensive technology and large capital expenditures are required to bring these undeveloped reserves onto production. As circumstances change and additional data becomes available, reserve estimates also change. Estimates 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 government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative. Degradation in future commodity price forecasts relative to the forecast in the Sproule Report can also have a negative impact on the economics and timing of development of undeveloped reserves, unless significant reduction in the future costs of development are realized.

Other than the foregoing, the Corporation does not anticipate any significant economic factors or significant uncertainties that may affect any particular components of the reserves data. However, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs; royalty regimes and well performance that are beyond the Corporation's control (see "*Risk Factors*").

For information with respect to abandonment and reclamation costs related to our properties to which reserves have been attributed, see "*Further Information Regarding Abandonment and Reclamation Costs*" below.

Further Information Regarding Abandonment and Reclamation Costs

The Sproule Report includes an estimate for abandonment and reclamation costs at December 31, 2019 for total proved plus probable reserves of $229.8 million undiscounted ($146.9 million of which is scheduled beyond 20 years) or approximately $42.5 million discounted at 10%, and for total proved reserves, $168.1 million undiscounted ($84.7million of which is scheduled beyond 20 years) or approximately $42.7 million discounted at 10%. Where included in the Sproule Report, abandonment and reclamation costs represent all costs associated with the process of restoring a company's properties, which have been disturbed by oil and gas activities, to a standard imposed by applicable government or regulatory authorities. The costs included in the Sproule Report represent the total decommissioning liabilities of the Corporation, including abandonment and reclamation cost obligations for the entities that have been assigned reserves, for material dedicated facilities required to produce these reserves, and abandonment and reclamation cost obligations for entities where no reserves have been assigned. The estimate in the Sproule Report includes abandonment and reclamation costs associated with future development activities including all development drilling, and material dedicated gathering and processing facilities required to produce the reserves included in the Sproule Report.

The following table sets forth undiscounted abandonment and reclamation costs included in the estimation of future net revenues attributable to the total proved plus probable reserve category contained in the Sproule Report:

Abandonment and Reclamation Costs	**Undiscounted ($M)**
Existing wells with developed reserves and associated facilities	47,577
Existing wells without developed reserves and associated facilities	76,484
Future wells with undeveloped reserves and associated facilities	105,770
Total abandonment and reclamation costs	229,831

The estimate for abandonment and reclamation costs is based on a number of sources including guidelines from provincial regulatory groups, historical data from our operations and management's estimation of costs to remediate, reclaim and abandon wells and facilities in which it has a working interest.

Crew has not established a reclamation fund to pay future asset retirement obligation costs. Crew projects incurring approximately $13.7 million ($11.4 million, discounted at 10%) in the next three years in respect of its abandonment and reclamation costs on non-producing wells with no reserves assigned. The future asset retirement obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserves categories noted below.

	Forecast Prices and Costs	
Year	Proved Reserves (MM$)	Proved Plus Probable Reserves (MM$)
2020	76	80
2021	139	150
2022	191	221
2023	164	187
2024	83	88
Thereafter	192	1,061
Total Undiscounted	844	1,787

Notes:
(1) Columns may not add due to rounding.

The Corporation currently expects that the capital listed in the preceding table will be funded through a combination of sources including internally generated cash flow from operations and, as required or applicable, property dispositions, new debt issuances, available credit facilities and, if determined appropriate, the issuance of Common Shares. Crew does not anticipate that the cost of funding would have any significant effect on the disclosed reserves or future net revenue, nor that interest or other costs of external funding would make development of any property uneconomic.

Estimates of reserves and future net revenues have been made assuming the development of each property, in respect of which the estimate is made, will occur without regard to the likely availability to the Corporation of funding required for the development. There can be no guarantee that funds will be available or that the Corporation will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop all of those reserves would have a negative impact on future cash flow from operations.

Other Oil and Gas Information

Principal Properties

Crew's operations are primarily focused on the development and growth of its Montney oil, liquids and condensate-rich natural gas assets in northeast British Columbia. In addition, the Corporation maintains its heavy oil assets in the Lloydminster area. The northeast British Columbia geographic area is made up of five areas: Septimus, West Septimus, (collectively referred to as "Greater Septimus"), Groundbirch/Monias, Attachie and Tower.

Crew's Board of Directors have approved 2020 capital expenditures of $35 million to $45 million, before acquisitions and dispositions, subject to ongoing review by management and the Board in light of world events. This level of capital investment is a reflection of the current extreme volatility in commodity prices and the heightened level of uncertainty associated with the global economy. The Corporation has taken a proactive approach to managing through this environment and expects that capital expenditures will be limited, while higher-cost or lower-netback production may be shut-in from time-to-time to preserve economics. Crew's focus in 2020 will be to preserve its reserves and resources, reduce water handling costs, optimize production and improve financial strength through debt reduction. The Corporation continues to prioritize financial flexibility and will take steps to refine its annual capital spending plans to maintain a strong balance sheet and focus on developing and producing the assets which provide the highest returns in the current environment.

The following is a description of Crew's principal properties, plants, facilities and installations as at December 31, 2019. Production stated is production before deduction of royalties and includes royalty interests to Crew and, unless otherwise stated, reflects average production for 2019. Reserve amounts are total proved plus probable reserves based on forecast prices and costs, stated before the deduction of royalties and without including any royalty interest of the Corporation as at December 31, 2019 based on forecast prices and costs as evaluated in the Sproule Report (see "*Reserves Data*"). **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.** Unless otherwise specified, gross and net acres and well count information are as at December 31, 2019.

West Septimus, British Columbia

The West Septimus area is located approximately 21 kilometres southwest of Fort St. John, British Columbia and includes lands west of the Pine River adjacent to Crew's Septimus area. The West Septimus operations include liquids-rich natural gas from the Montney formation which is a tight siltstone formation that is up to 300 meters in thickness. It is now being developed with extended reach horizontal wells that are completed with multi-stage water-based fracture stimulations. Crew's production from this area in 2019 averaged 13,034 boe/d weighted 71% to natural gas, 17% condensate and 12% to other liquids. At December 31, 2019, the Corporation had 83 (81.2 net) producing liquids-rich natural gas wells. The Corporation's current production is processed through Crew's operated West Septimus facility, which at year end 2019 was owned 28.0% by the Corporation, and which will be reduced to 22% following second closing of the Midstream Transactions anticipated in Q4 2020. In 2019, Crew drilled six (6.0 net) and completed thirteen (13.0 net) gas wells in the area. One of these wells was completed over only a portion of its length (~25%) for data gathering purposes, with the remainder of this well to be completed as part of a future completions program once the remaining wells are drilled on the pad. This partially completed well has not been included in Crew's completion statistics herein.

Crew currently has no plans to drill or complete any Montney wells in West Septimus in 2020. Crew expects to drill and complete one horizontal water disposal well within the Cadomin Formation during 2020. Disposal operations are planned to commence in late 2020.

During 2018, Crew constructed a pipeline system from the West Septimus facility through Groundbirch to tie the facility into the Saturn meter station on the TransCanada Pipeline System. This project provides Crew with physical access to all three major natural gas egress systems transporting natural gas out of Western Canada. In addition, the configuration of this new infrastructure allows Crew the ability to begin development of the Groundbirch area by providing access to the West Septimus processing facility.

As at December 31, 2019, the Sproule Report assigned proved plus probable reserves of 55,522.8 Mbbl of NGL and 960,427 Mmcf of natural gas to Crew's interests in the West Septimus area. At year-end 2019, the Corporation owned 34,748 net acres of land with an average working interest of 88.5% in the area.

Septimus, British Columbia

The Septimus area is located approximately 13 kilometres southwest of Fort St. John in British Columbia. Crew's operations include liquids-rich natural gas from the Montney formation. At December 31, 2019, Crew had an interest in 65 (61.0 net) producing liquids-rich natural gas wells and two (1.3 net) service wells in the area. In 2019, production averaged 5,770 Boe/d weighted 86% to natural gas, 7% condensate and 7% to other liquids. Crew did not drill or complete any wells in this area in 2019. Production from the Montney is processed through a facility operated by the Corporation and in which Crew owned a 28.0% working interest at year end 2019. Following the second closing of the Midstream Transactions anticipated in Q4 2020, Crew will retain a 22% WI in the facility. Due to the current low price of natural gas in Canada, the Corporation currently has no plans to drill or complete wells in the Septimus area in 2020.

As at December 31, 2019, the Sproule Report assigned total proved plus probable reserves of 5,322.6Mbbl of oil and 12,606.3 Mbbl of NGL along with 364,092 Mmcf of natural gas to Crew's interests in the Septimus area. At year-end 2019, the Corporation owned 14,393 net acres of land with an average working interest of 91% in this area.

Tower, British Columbia

The Tower area is located approximately 13 kilometres south of Fort St. John, British Columbia. Crew's operations include oil and liquids-rich solution gas from the Montney formation. In 2019, Crew's production from the area averaged 698 boe/d weighted 29% to oil, and 61% to natural gas and 10% to NGL. At December 31, 2019, the Corporation had 11 (9.7 net) producing oil wells in the area. Crew did not drill or complete any wells in this area in 2019. Crew's gas production in the Tower area is processed through the Crew owned Septimus gas facility and the oil production is trucked to market from a 100% Crew owned and operated oil processing facility. The Corporation currently has no plans to drill or complete wells in the Tower area in 2020.

As at December 31, 2019, the Sproule Report assigned proved plus probable reserves of 2,340.9 Mbbl of oil and NGL and 13,820 Mmcf of natural gas to Crew's interests in the Tower area. At year-end 2019, the Corporation owned 34,570 net acres of land with an average working interest of 84% in the area.

Groundbirch/Monias, British Columbia

The Groundbirch/Monias area is located approximately 35 km southwest of Fort St. John, British Columbia and includes lands adjacent to and southwest of West Septimus. Crew's operations in this area include liquids-rich natural gas production from the Montney, Halfway and Belloy formations. In 2019, the Corporation's production from this area averaged 1,545 boe/d weighted 93% to natural gas, 3% to condensate and 4% to other NGL. At December 31, 2019, the Corporation had ten (9.7 net) producing natural gas wells. In 2019, Crew drilled one (1.0 net) and completed one (1.0 net) gas wells in the Monias area. In December of 2018, four Groundbirch Montney wells were tied in to Crew owned and operated pipeline and since that time have been producing through the West Septimus gas plant. The remainder of the Corporation's production in the Groundbirch/Monias area continues to be processed through third party facilities. The Corporation currently has no plans to drill or complete wells in the Groundbirch/Monias area in 2020.

As at December 31, 2019, the Sproule Report assigned proved plus probable reserves of 9,229.8 Mbbl of oil and NGL and 364,382 Mmcf of natural gas to Crew's interests in the Groundbirch/Monias area. At year-end 2019, the Corporation owned 132,060 net acres of land with an average working interest of 80.6% in the area.

Attachie, British Columbia

The Attachie area is located approximately 59 kilometres west of Fort St. John in British Columbia. Crew's operations target liquids-rich natural gas from the Montney formation. At December 31, 2019, the Corporation had no producing gas wells or oil wells in this area. One (1.0 net) lease retention well was drilled in this area in January of 2019 and another one (1.0 net) is planned in 2020, neither of which are currently planned to be completed and brought on-stream. This is expected to conclude the lease preservation program in this area.

As at December 31, 2019, the Sproule Report assigned proved plus probable reserves of 6,618.7 Mbbl of oil and NGL and 161,626 Mmcf of natural gas to Crew's interests in the Attachie area. At year-end 2019, the Corporation owned 37,785 net acres of land with an average working interest of 97% in the area.

Lloydminster, Saskatchewan/Alberta

The Lloydminster area includes Crew's operations at Wildmere, Swimming, Viking-Kinsella, Baldwinton, Forest Bank, Golden Lake, Lashburn West, Low Lake, Lloydminster, Lindbergh, Neilburg and Unwin-Epping and is situated in the Saskatchewan/Alberta border region near the city of Lloydminster, Saskatchewan. The Corporation's production in the area is comprised of 12° to 14° API oil from several stacked Cretaceous aged reservoirs in stratigraphic and structural traps along with Devonian aged carbonate units that are trapped along the subcrop edge. Development includes conventional vertical and horizontal wells completed for primary and secondary waterflood production from these reservoirs.

At December 31, 2019 the Corporation owned 113 (99.6 net) producing oil wells and 11 (11.0 net) service wells, along with a 100% owned oil battery and numerous single and multi-well batteries located at individual well sites. Crew did not drill any wells in the Lloydminster area in 2019. Production for 2019 averaged 1,646 boe/d weighted 99% to heavy crude oil and

1% to natural gas. The majority of the Corporation's oil production from the Lloydminster area is processed at the Corporation's 100% owned oil battery which is directly tied into the Manito Pipeline System. Crew plans to drill two (2.0 net) oil wells in this area in 2020.

As at December 31, 2019, the Sproule Report assigned proved plus probable reserves of 7,567.5 Mbbl of heavy crude oil and 82 Mmcf of natural gas to Crew's interests in the Lloydminster area. At year-end 2019, the Corporation owned 45,216 net acres of land with an average working interest of 91.7% in the area.

Other Minor Properties

In addition to the foregoing, Crew has interests in other minor, predominantly non-operated, properties in northeast British Columbia which contributed, in the aggregate, approximately 143 boe/d of production in 2019. As at December 31, 2019, the Corporation owned one (0.3 net) producing oil well and 15 (5.4 net) producing gas wells.

Oil and Gas Wells

The following table sets forth the number and status of oil and natural gas wells in which the Corporation has a working interest as at December 31, 2019.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	40	40	106	105	-	-	7	6
British Columbia	12	10	9	5	173	157	192	96
Saskatchewan	73	60	336	292	-	-	8	7
Total	125	110	451	402	173	157	207	109

Land Holdings Including Properties with No Attributed Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2019.

	Developed Acres		Undeveloped Acres(1)	
	Gross	Net	Gross	Net
Alberta	6,039	5,501	4,800	4,246
British Columbia	155,059	81,771	390,226	314,714
Saskatchewan	16,060	13,147	22,967	22,611
Other Canada	-	-	376,920	43,896
Total	**177,159**	**100,418**	**794,913**	**385,467**

Note:

(1) Undeveloped Acres includes our interest in 794,913 gross acres (385,467 net acres) of unproved property land holdings, being properties or part of properties to which no reserves have been specifically attributed. Crew has no material work commitments related to our unproved properties.

Of the Corporation's undeveloped land, the rights to explore develop and exploit 29,858 undeveloped acres (47 sections) may expire by December 31, 2020 if the Corporation takes no action to retain the land. Crew plans to submit applications to continue selected portions of this acreage.

In those situations where Crew holds interests in different formations under the same surface area pursuant to separate leases, Crew would consider this to be two separate leases and would calculate them separately. This would arise where Crew has purchased rights through Crown land sales, expending funds to acquire both leases separately based on the specific geological risk associated with the rights of each lease.

In the current price environment and accounting for a risked assessment of hydrocarbon potential, Crew may delay certain exploration and development investment decisions in order to maximize the value of the properties with no attributed reserves but retaining the mineral rights for future development.

For information with respect to abandonment and reclamation costs for our properties with no attributed reserves, see "*Further Information Regarding Abandonment and Reclamation Costs*" above.

Forward Contracts and Marketing

With the exception of the following financial derivative contracts entered into pursuant to the Corporation's risk management program, as of December 31, 2019, Crew does not have any material commitments to buy or sell natural gas or crude oil production.

As at December 31, 2019, the Corporation held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	12,500 mmbtu/day	January 1, 2020 - December 31, 2020	Chicago Citygate	$3.32/mmbtu	Swap	$ 2,300
Gas	2,500 mmbtu/day	January 1, 2020 - December 31, 2020	US$ Nymex Henry Hub	$2.48/mmbtu	Swap	199
Oil	250 bbl/day	January 1, 2020 - June 30, 2020	CDN$ WTI	$75.50/bbl	Swap	(102)
Oil	250 bbl/day	January 1, 2020 - June 30, 2020	USD$ WCS - WTI Differential	($17.25)/bbl	Swap	131
Oil	500 bbl/day	January 1, 2020 - June 30, 2020	CDN$ WCS	$52.25/bbl	Swap	(9)
Oil	1,000 bbl/day	January 1, 2020 - December 31, 2020	CDN$ WTI	$77.65/bbl	Swap	639
Oil	250 bbl/day	July 1, 2020 - December 31, 2020	CDN$ WCS	$51.50/bbl	Swap	5
Condensate	250 bbl/day	January 1, 2020 - March 31, 2020	USD$ C5+ Differential	$2.00/bbl	Swap	17
Total						**$ 3,180**

Subsequent to December 31, 2019, the Company entered into the following derivative commodity contracts:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	250 bbl/day	July 1, 2020 - Sept. 30, 2020	USD$ WCS - WTI Differential	($16.00/bbl)	Swap
Oil	250 bbl/day	July 1, 2020 - Dec. 31, 2020	CDN$ WTI	$76.00/bbl	Swap
Oil	250 bbl/day	July 1, 2020 - Dec. 31, 2020	USD$ WCS - WTI Differential	($15.60/bbl)	Swap
Gas	2500 mmbtu/day	Nov. 1, 2020 - Oct. 31, 2021	CDN$ Chicago Gas Daily	$3.15/mmbtu	Swap
Gas	2500 mmbtu/day	Nov. 1, 2020 - Oct. 31, 2021	CDN$ Chicago NGI Monthly	$3.17/mmbtu	Swap

Pipeline Transportation and Production Processing Commitments

Part of Crew's ongoing strategy includes securing processing and transportation capacity to ensure the Corporation's production moves to market over the short and long term. Crew believes that securing firm takeaway capacity is prudent management of its business, and as such, has secured sufficient takeaway for anticipated future growth. The Corporation's processing and transportation commitments available for future physical deliveries of oil, natural gas and natural gas liquids exceed Crew's expected related future production of its proved reserves, using forecast prices and costs based on the Sproule Report.

The estimated cost of excess firm takeaway capacity as compared to Crew's proved reserves forecast is $31 million in the first 5 years of the forecast and $4 million thereafter. Transportation volume shortfalls in the first five years are 61 mmcf/d of natural gas and 56 bbls/d of crude oil and NGL. After five years, transportation volume shortfalls are 22 mmcf/d of natural gas and 0 bbls/d of crude oil and NGL. Processing volume shortfalls occur in the first five years and are 1 mmcf/d of natural gas.

Crew expects to fulfill these commitments through its ongoing exploration and development activities subject to the Corporation's ongoing development plans and associated capital requirements, well performance and disruptions or constraints at facilities and pipelines. In cases where Crew holds transportation commitments for volume that exceeds its expected future production from proved and proved plus probable reserves, it has identified, and will continue to identify, opportunities where it may reduce its exposure to negative cash flows arising from the settlements of these contract obligations.

The production, processing and transportation of natural gas, NGL and oil are interdependent and Crew's ability to fulfill each commitment could be impacted by well performance and disruptions and constraints at the Corporation's and/or at third-party facilities and pipelines. The Corporation could experience a financial loss and its operations could be adversely affected if Crew is unable to fulfill its commitments through its operations or, where necessary, amend its commitments or assign any excess capacity to one or more third-parties. Additional disclosure related to such commitments can be found in the Corporation's audited consolidated financial statements as at and for the year ended December 31, 2019, which can be found under Crew's profile on SEDAR at www.sedar.com.

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2019. Based on current estimates of the Corporation's future taxable income and levels of tax deductible expenditures, management believes that the Corporation will not be required to pay cash income taxes in 2020 and does not anticipate being in a cash income tax payable situation through 2022 and beyond at the currently anticipated rate of capital expenditures and forecasted commodity prices.

Costs Incurred

The following table summarizes capital expenditures (net of incentives and net of disposition proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2019:

	($ thousands)
Property acquisition costs	
Proved properties	1,570
Unproved properties	3,311
Exploration costs	1,163
Development costs	109,620
Corporate acquisitions	-
Property dispositions	(20,654)
Total	95,010

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated in drilling during the year ended December 31, 2019.

	Gross			Net		
	Exploration	Development	Total	Exploration	Development	Total
Crude Oil	-	-	-	-	-	-
Natural Gas	1	7	8	1	7	8
Dry[(1)]	-	-	-	-	-	-
Service[(2)]	-	-	-	-	-	-
Stratigraphic Test	-	-	-	-	-	-
Total:	1	7	8	1	7	8

Notes:

(1) "Dry well" means a well which is not a productive well or a service well. A productive well is a well which is capable of producing oil and gas in commercial quantities or in quantities considered by the operator to be sufficient to justify the costs required to complete, equip and produce the well.

(2) A service well means a well such as a water or gas-injection, water-source or water-disposal well. Such wells do not have marketable reserves of crude oil or natural gas attributed to them but are essential to the production of the crude oil and natural gas reserves.

For details on Crew's important current and likely exploration and development activities during 2020, see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*".

Production Estimates

The following table sets out the volume of the Corporation's average estimated daily production for the year ended December 31, 2020 as estimated in the Sproule Report which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light Crude Oil and Medium Crude Oil		Heavy Crude Oil		Natural Gas Liquids		Conventional Natural Gas		Total Oil Equivalent	
Reserves Category	Gross (bbl/d)	Net (bbl/d)	Gross (bbl/d)	Net (bbl/d)	Gross (bbl/d)	Net (bbl/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (Boe/d)	Net (Boe/d)
Total Proved										
Septimus	112	90	0	0	1,063	887	29,683	26,675	6,122	5,423
West Septimus	0	0	0	0	4,066	3,660	56,667	51,967	13,511	12,321
Other	124	115	1,932	1,713	180	158	11,642	11,238	4,176	3,860
Total Proved Plus Probable										
Septimus	135	108	0	0	1,098	916	30,656	27,557	6,342	5,616
West Septimus	0	0	0	0	4,728	4,227	63,631	58,270	15,333	13,939
Other	130	121	2,420	2,115	193	176	12,240	11,809	4,783	4,380

Note:

(1) The Corporation's Septimus and West Septimus areas comprise the only individual fields that account for 20% or more of the Corporation's estimated 2020 production as reflected in the Sproule Report.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, transportation expenses, operating expenses, marketing income and resulting netback associated with Crew's assets for the periods indicated below:

	Quarter Ended			
	2019			
	Dec. 31	**Sept. 30**	**Jun. 30**	**Mar. 31**
Average Daily Production(1)				
Light Crude Oil and Medium Crude Oil (bbl/d)	251	233	155	226
Heavy Crude Oil (bbl/d)	1,600	1,627	1,722	1,608
Conventional Natural Gas (Mcf/d)	96,776	97,443	94,873	100,542
NGLs (bbl/d)	4,466	4,723	5,176	4,631
Combined (BOE/d)	22,446	22,824	22,865	23,222
Average Price Received(2)				
Light Crude Oil and Medium Crude Oil ($/bbl)	62.85	63.81	66.15	61.04
Heavy Crude Oil ($/bbl)	44.76	52.86	60.00	44.25
Conventional Natural Gas ($/Mcf)	2.36	1.95	2.34	3.45
NGLs ($/bbl)	38.69	34.17	44.63	39.87
Combined ($/BOE)	21.76	19.81	24.77	26.53
Marketing Income				
Combined ($/BOE)	(0.02)	1.33	1.23	1.40
Transportation Expenses				
Light Crude Oil and Medium Crude Oil ($/bbl)	1.82	0.70	2.40	3.89
Heavy Crude Oil ($/bbl)	0.40	0.61	0.19	1.02
Conventional Natural Gas ($/Mcf)	0.66	0.65	0.71	0.49
NGLs ($/bbl)	(0.04)	(0.08)	0.14	0.20
Combined ($/BOE)	2.88	2.80	3.01	2.26
Royalties Paid				
Light Crude Oil and Medium Crude Oil ($/bbl)	6.72	4.99	4.59	5.61
Heavy Crude Oil ($/bbl)	6.05	7.91	8.53	5.21
Conventional Natural Gas ($/Mcf)	0.21	0.02	0.10	0.20
NGLs ($/bbl)	2.87	2.23	3.02	2.84
Combined ($/BOE)	1.97	1.16	1.77	1.85
Operating Expenses				
Light Crude Oil and Medium Crude Oil ($/bbl)	26.76	29.34	43.18	33.43
Heavy Crude Oil ($/bbl)	21.94	22.58	20.43	21.90
Conventional Natural Gas ($/Mcf)	0.72	0.81	0.84	0.89
NGLs ($/bbl)	4.26	4.62	4.74	4.88
Processing revenue ($/BOE)	(0.07)	(0.08)	(0.09)	(0.10)
Combined ($/BOE)	5.51	5.94	6.01	6.25
Netback Received(3)(4)				
Light Crude Oil and Medium Crude Oil ($/bbl)	27.55	28.78	15.98	18.11
Heavy Crude Oil ($/bbl)	16.37	21.76	30.85	16.12
Conventional Natural Gas ($/Mcf)	0.77	0.47	0.69	1.97
NGLs ($/bbl)	31.60	27.41	36.73	31.95
Combined ($/BOE)	11.38	11.24	15.21	17.57

Notes:

(1) Before deduction of royalties and including royalty interests.
(2) Average price received does not include the impact of the Corporation's realized gains and losses on derivative financial instruments.
(3) Netbacks are calculated by subtracting transportation, royalties and operating costs from revenues plus marketing income.
(4) Refer to the section entitled "*Non-IFRS Measures*" contained within Crew's MD&A for the year ended December 31, 2019, which section is incorporated in this Annual Information Form by reference and is found on our SEDAR profile at www.sedar.com.

The following table indicates the Corporation's average daily production, before deduction of royalties and including royalty interests, from its important fields for the year ended December 31, 2019:

	Light Crude Oil & Medium Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLS (bbl/d)	Oil Equivalent (BOE/d)
Lloydminster Alberta	-	864	47	-	872
Total Alberta	**-**	**864**	**47**	**-**	**872**
Septimus	-	-	29,678	824	5,770
West Septimus	-	-	55,867	3,723	13,603
Other	216	-	11,806	202	1,817
Total British Columbia	**216**	**-**	**97,351**	**4,749**	**21,190**
Lloydminster Saskatchewan	-	775	-	-	775
Total Saskatchewan	**-**	**775**	**-**	**-**	**775**
Total	**216**	**1,639**	**97,398**	**4,749**	**22,837**

For the year ended December 31, 2019, approximately 17% of Crew's gross production revenue was derived from crude oil and natural gas liquids production (other than condensate), 12% was derived from condensate production, and 71% was derived from natural gas production. The NGL production shown above includes condensate, which represented 49% of total NGLs at Septimus, 60% at West Septimus, 36% at Other and 57% of Total British Columbia.

DIVIDEND POLICY

Crew has never declared or paid any dividends on its outstanding Common Shares. Crew does not currently anticipate paying any dividends on its Common shares in the foreseeable future but will review that policy from time to time as circumstances warrant. Crew currently intends to retain future earnings, if any, for future operations, growth and debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board of Directors and will depend on, among other things, the Corporation's results of operations, current and anticipated cash requirements and surplus, financial condition, solvency tests imposed by corporate law, contractual restrictions and financing agreement covenants, if any, and other factors that the Board may determine relevant.

Pursuant to the terms governing the 2024 Notes, Crew and certain of its subsidiaries are prohibited from making certain restricted payments, including the payment of dividends, unless at the time of and immediately after giving effect to such a proposed restricted payment certain financial tests are met, and no default or event of default under the Notes has occurred and is continuing.

Pursuant to Crew's Credit Facility, Crew is not permitted to make distributions when there is a borrowing base shortfall or which would reasonably be expected to have a material adverse effect except for distributions (i) payable in common shares, (ii) consisting of certain purchases, redemptions and acquisitions of shares or (iii) consisting of scheduled interest payments on any high yield notes to an affiliate or other related party. In addition, no distributions are permitted during a default or event of default under the Credit Facility.

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares without nominal or par value. The following is a description of the rights, privileges, restrictions and conditions attaching to the Common Shares.

Common Shares

Holders of Common Shares are entitled to notice of, to attend and to one vote per Common Share held at meetings of shareholders of the Corporation and are entitled to dividends if, as and when declared by the Board of Directors and, upon liquidation, dissolution or winding-up, to receive the remaining property of the Corporation.

Senior Unsecured Notes

On March 14, 2017, the Corporation completed a private placement offering of $300 million aggregate principal amount of senior unsecured notes which bear interest at 6.500% per annum, payable semi-annually on March 14 and September 14 of each year and maturing on March 14, 2024 (the "**2024 Notes**"). At any time prior to March 14, 2020, the Corporation may redeem the 2024 Notes, in whole or in part, at a price equal to 100% of the principal amount of the 2024 Notes being redeemed plus accrued but unpaid interest, if any, to, but not including, the redemption date plus a "make whole" premium. The Corporation may also, at any time prior to March 14, 2020, redeem up to 35% of the aggregate principal amount of the 2024 Notes with the net cash proceeds from certain equity offerings at a redemption price of 106.500%, plus accrued and unpaid interest to the applicable redemption date. At any time on or after March 14, 2020, the Corporation may redeem the 2024 Notes, in whole or in part, at the following redemption prices plus accrued and unpaid interest on the 2024 Notes redeemed, to the applicable redemption date, if redeemed during the twelve (12) month period beginning on March 14 of each of the following years: 2020 – 103.250%; 2021 – 102.145%; 2022 – 101.040%; and 2023 and thereafter – 100.000%.

If the Corporation undergoes certain kinds of changes of control, it is required to offer to repurchase the 2024 Notes from holders at a purchase price equal to not less than 101% of the principal amount of the 2024 Notes plus accrued and unpaid interest to, but not including, the date of repurchase.

The 2024 Notes are senior unsecured obligations of the Corporation ranking equally in right of payment with all existing and future indebtedness of the Corporation that is not expressly subordinated in right of payment to the 2024 Notes and senior in right of payment to all future indebtedness of the Corporation that is expressly subordinated to the 2024 Notes. The 2024 Notes are guaranteed, jointly and severally, on a senior unsecured basis by the Corporation's material subsidiaries. The 2024 Notes are effectively subordinated to any secured indebtedness of the Corporation, including the Corporation's Credit Facility (as defined below), to the extent of the value of the assets securing such secured indebtedness.

Subject to certain exceptions and qualifications set forth in the indenture governing the 2024 Notes, the 2024 Notes limit the ability of the Corporation and certain of its subsidiaries that are considered to be "restricted subsidiaries" to, among other things: make restricted payments; incur additional indebtedness and issue disqualified or preferred stock; create or permit to exist liens; create or permit to exist restrictions on the ability of the restricted subsidiaries to make certain payments and distributions; make certain dispositions and transfers of assets; engage in amalgamations, mergers or consolidations; and engage in certain transactions with affiliates.

On October 21, 2013, the Corporation completed a private placement offering of $150 million aggregate principal amount of senior unsecured notes bearing interest at 8.375% per annum, maturing on October 21, 2020 (the "**2020 Notes**"). Under the terms of the governing note indenture, at any time on or after October 21, 2016, the Corporation was entitled to redeem the 2020 Notes, in whole or in part. Effective March 23, 2017, following completion of the issuance of the 2024 Notes, the Corporation redeemed the 2020 Notes at a redemption price of $1,041.88 for each $1,000 of principal amount redeemed, plus accrued and unpaid interest to, but not including, the redemption date.

Credit Facility

The Corporation has a credit facility with a syndicate of lenders which, as at the date hereof, provides for a $210 million extendible revolving line of credit and a $25 million operating line of credit (collectively, the "**Credit Facility**"). The Credit Facility revolves for a 364 day period and is subject to its next 364 day extension by June 4, 2020. If not extended, the Credit Facility will cease to revolve, the margins thereunder will increase by 0.50% and all outstanding advances thereunder will become repayable in one year from the current term date. The available lending limits of the Credit Facility are reviewed semi-annually and are based on the lenders' assessment of the Corporation's reserves and future commodity prices.

RATINGS

The following information relating to the Corporation's credit ratings is provided as it relates to the Corporation's financing costs, liquidity and costs of operations. Credit ratings impact the Corporation's ability to obtain short term and long term financing and the cost of such financings. Changes in the Corporation's current credit ratings by the rating agencies, particularly downgrades below the current ratings or negative changes in the ratings outlook, could adversely affect the Corporation's cost of borrowing and/or access to sources of liquidity and capital.

The Corporation has been assigned corporate credit ratings of B by DBRS Limited ("**DBRS**") with a stable trend and B- by Standard & Poors Rating Services ("**S&P**") with a stable trend. The corporate credit rating focuses on a borrower's capacity and willingness to meet its financial commitments as they come due. The 2024 Notes have been assigned credit ratings of B by DBRS with a stable trend and B by S&P with a stable trend. DBRS and S&P provide credit ratings of debt securities for commercial entities. A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments.

The Corporation has been recently informed that both DBRS and S&P are in the process of undertaking rating reviews with negative implications for issuers involved in the oil and gas producer and services sectors, including Crew. This undertaking is in response to the recent extreme oil price declines and significant increase in volatility in associated markets, largely caused by the rapid spread of COVID-19 and the concurrent crude oil price war between OPEC and Russia.

DBRS' credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. DBRS has assigned the Corporation a credit rating of B on the 2024 Notes. A reference to "high" or "low" reflects the relative strength within the rating category, while the absence of either a "high" or "low" designation indicates the rating is placed in the middle category. Ratings trends provide guidance in respect of DBRS's opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories – "Positive", "Stable" or "Negative". The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed. In general, the DBRS view is based primarily on an evaluation of the issuing entity or guarantor itself, but may also include consideration of the outlook for the industry or industries in which the issuing entity operates.

S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. S&P has assigned the Corporation a credit rating of B on the 2024 Notes. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A rating can be revised, suspended or withdrawn at any time by the rating agency.

The Corporation paid a fee for service to both DBRS and S&P to provide ratings in respect of the offering of the Notes and pays an annual fee to both firms to maintain the corporate and note ratings. No other service fees were paid by the Corporation to these organizations during the last two years.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX and trade under the symbol "CR". The following sets forth trading information for the Common Shares (as reported by the TSX) for the periods indicated.

	Price Range ($)		
Period	**High**	**Low**	**Volume**
2019			
January	$ 0.99	$ 0.81	16,602,946
February	$ 0.96	$ 0.84	8,560,370
March	$ 1.29	$ 0.91	16,994,507
April	$ 1.36	$ 1.10	11,010,216
May	$ 1.12	$ 0.90	9,129,818
June	$ 0.99	$ 0.81	5,935,094
July	$ 0.83	$ 0.71	6,685,222
August	$ 0.76	$ 0.58	5,244,280
September	$ 0.86	$ 0.58	6,810,094
October	$ 0.68	$ 0.47	7,366,558
November	$ 0.51	$ 0.40	7,214,403
December	$ 0.62	$ 0.41	8,626,117
2020			
January	$ 0.58	$ 0.44	12,388,961
February	$ 0.46	$ 0.29	10,670,398
March (1 – 25)	$ 0.39	$ 0.14	13,415,287

Prior Sales of Unlisted Securities

The following table summarizes the issuances of securities of the Corporation that are not listed or quoted on a marketplace during the most recently completed financial year of the Corporation.

Date of Issuance	Type of Securities[(1)]	Number of Securities	Price Per Security
Mar 18, 2019	Incentive Awards	36,000	N/A
Apr 1, 2019	Incentive Awards	3,802,600	N/A
May 13, 2019	Incentive Awards	24,000	N/A
May 27, 2019	Incentive Awards	12,800	N/A

Note:

(1) Reflects incentive awards in the form of "Restricted Awards" and "Performance Awards" issued under the Corporation's restricted and performance award incentive plan.

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

DIRECTORS AND OFFICERS

The name, age, province and country of residence, position with the Corporation and principal occupation of the current directors and officers of the Corporation, as applicable, are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name, Age, Province and Country of Residence	Office Held	Date First Elected or Appointed as a Director	Principal Occupation
John A. Brussa(2)(3) Alberta, Canada Age: 63	Chairman	September, 2003	Partner and Chairman, Burnet, Duckworth & Palmer LLP (a Calgary law firm).
Jeffery E. Errico(2)(3)(4) Alberta, Canada Age: 69	Lead Independent Director	September, 2008	Independent business person; Chairman of Insignia Energy Ltd. From 2007 to 2017; prior thereto, President and Chief Executive Officer of Petrofund Energy Trust, a public oil and gas trust, from April 2003 to June 2006.
Dennis L. Nerland, Q.C.(1)(4) Alberta, Canada Age: 67	Director	September, 2003	Partner, Nerland Lindsey LLP (a law firm).
Karen Nielsen(2)(3) Alberta, Canada Age: 52	Director	May, 2018	Chief Development Officer, Seven Generations Energy since June, 2019; prior thereto was Senior Vice President and General Manager, Generation at ATCO Electricity Generation since August, 2017; prior thereto, Vice President, Operations at ARC Resources Ltd. from 2013 to 2017.
Ryan Shay CPA, CA, CFA (1)(2) Alberta, Canada Age: 48	Director	May, 2018	Independent business person since 2016; prior thereto, Managing Director, Head of Investment Banking at Cormark Securities Inc.
David G. Smith(1)(4) Alberta, Canada Age: 62	Director	January, 2009	Chief Executive Officer and Director of Keyera Corp. since January 1, 2015; prior thereto, President and Chief Operating Officer of Keyera Corp. since May, 2011; prior thereto, Executive Vice President, Liquids Business Unit, Keyera Corp. since January 1, 2011 and of Keyera Facilities Income Fund since November 2008; prior thereto, Executive Vice President and Chief Financial Officer, Keyera Facilities Income Fund since February 2006; prior thereto, Senior Vice President and Chief Financial Officer, Keyera Facilities Income Fund.

Name, Age, Province and Country of Residence	Office Held	Date First Elected or Appointed as a Director	Principal Occupation
Dale O. Shwed Alberta, Canada Age: 61	President, Chief Executive Officer and Director	June, 2003	President and Chief Executive Officer of the Corporation since June, 2003; prior thereto, President and Chief Executive Officer of Baytex.
John G. Leach, CPA, CA Alberta, Canada Age: 55	Executive Vice-President and Chief Financial Officer	N/A	Executive Vice-President and Chief Financial Officer of the Corporation since December 2018; prior thereto Senior Vice-President and Chief Financial Officer of the Corporation since January, 2009; prior thereto, Vice-President and Chief Financial Officer of the Corporation since September, 2003; prior thereto, Vice President, Finance and Administration of Baytex.
James Taylor Alberta, Canada Age: 45	Chief Operating Officer	N/A	Chief Operating Officer of the Corporation since March, 2018; prior thereto, Vice President and Engineering Manager of XTO Energy Canada since 2015, and prior thereto, Engineering Manager with XTO Energy Canada since 2014; various operations/ engineering roles with ExxonMobil for 3.5 years and prior thereto, 13 years with Imperial Oil.
Jamie L. Bowman Alberta, Canada Age: 55	Senior Vice-President, Marketing and Originations	N/A	Senior Vice-President, Marketing and Originations of the Corporation since December, 2018; and prior thereto, Vice-President, Marketing and Originations of the Corporation since December, 2017; prior thereto, Vice President, Marketing since April, 2013; prior thereto, Vice President, Marketing and Business Development, EOG Resources Canada Inc. since September 2012; prior thereto, Vice President Marketing, EOG Resources Canada Inc. since September, 2003.
Paul A. Dever Alberta, Canada Age: 54	Vice-President, Government and Stakeholder Relations	N/A	Vice-President, Government and Stakeholder Relations of the Corporation since January, 2018; prior thereto, Director, Government & Stakeholder Relations of the Corporation since 2014; prior thereto, Manager, Surface Land & Community Relations of the Corporation since 2008; Prior thereto, Surface Landman of the Corporation since August 2005.

Name, Age, Province and Country of Residence	Office Held	Date First Elected or Appointed as a Director	Principal Occupation
Kevin Evers Alberta, Canada Age: 47	Vice-President, Geosciences	N/A	Vice President, Geosciences of the Corporation since January, 2018; prior thereto, Manager, Geosciences of the Corporation since 2017; prior thereto Manager, Business Development since 2014; prior thereto Manager, Geosciences (Alberta) of the Corporation since 2011; prior thereto Senior Geologist of the Corporation since 2007.
Kurtis Fischer Alberta, Canada Age: 52	Vice-President, Planning & Development	N/A	Vice-President, Planning & Development since July, 2017 and prior thereto, served as Vice President across various business lines including Business Development and Production of the Corporation since May, 2010; prior thereto, Manager, Acquisitions and Divestitures of the Corporation since April, 2008; prior thereto, Senior Engineering Technologist of the Corporation since August, 2004.
Mark Miller Alberta, Canada Age: 44	Vice-President, Land and Negotiations	N/A	Vice-President, Land and Negotiations of the Corporation since January, 2018; prior thereto, Land Manager of the Corporation since 2011; prior thereto, Senior Landman of the Corporation since 2007.
Michael D. Sandrelli Alberta, Canada Age: 51	Corporate Secretary	N/A	Partner and Executive Committee member, Burnet, Duckworth & Palmer LLP (a Calgary law firm).

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) Member of the Corporate Governance Committee.
(5) Crew does not have an Executive Committee of its Board of Directors.

All of the directors and officers of Crew have been engaged for more than five years in their present principal occupations or executive positions with the same companies except as described above.

The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at December 31, 2019, the directors and executive officers of Crew, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 10.1 million Common Shares representing approximately 6.5% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To Crew's knowledge, other than as disclosed herein, no director or executive officer of the Corporation is, as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any issuer (including the Corporation) that: (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes of the above, "order" means a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Bankruptcies

To Crew's knowledge, other than as disclosed herein, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation (a) is, as at the date hereof, or has been, within the 10 years before the date hereof, a director or executive officer of any issuer (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Mr. Nerland was appointed as a director of Alston Energy Inc. ("**Alston**") on July 17, 2012. On December 9, 2013, Alston filed for protection under the *Companies' Creditors Arrangement Act* (Canada). On May 6, 2014 and May 8, 2014, the common shares of Alston were cease traded by the Alberta Securities Commission and the British Columbia Securities Commission, respectively, as a result of the failure by Alston to file audited annual financial statements and the related management discussion and analysis for the year ended December 31, 2013. On May 9, 2014, Alston announced that a receiver had been appointed by the Court of Queen's Bench of Alberta.

Mr. Nerland was appointed a director of Manitok Energy Inc. ("Manitok") on June 25, 2014. On February 21, 2018, the Court of Queen's Bench of Alberta made orders appointing a receiver and trustee in bankruptcy of Manitok. All of the directors of Manitok, including Mr. Nerland, resigned as a result of the appointment of the receiver and the bankruptcy.

Mr. Nerland was appointed as a director and officer of Arkadia Capital Corp. on November 1, 2011. On January 4, 2019 the common shares of Arkadia were cease traded by the Alberta Securities Commission as a result of the failure by Arkadia to file audited annual financial statements and related MD&A for the year ended August 31, 2018. Mr. Nerland resigned as a director and officer on March 13, 2019.

Mr. John Brussa resigned as a director of Calmena Energy Services Inc. ("**Calmena**") on June 30, 2014. On January 19, 2015, a senior lender of Calmena (the "**Senior Lender**") made an application to the Court of Queen's Bench of Alberta (the "**Court**") to appoint an interim receiver under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Calmena was suspended by the Toronto Stock Exchange. On January 20, 2015, the Senior Lender was granted a receivership order by the Court.

Mr. Brussa was also a director of Enseco Energy Services Corp. ("**Enseco**"), a public oilfield service company, which was placed in receivership on October 14, 2015 and, in connection therewith, a receiver was appointed under the *Bankruptcy and Insolvency Act* (Canada). Mr. Brussa resigned as a director of Enseco on October 14, 2015. On December 21, 2015 Enseco was assigned into bankruptcy by the receiver.

Mr. Brussa was a director of Argent Energy Ltd. Which was the administrator of Argent Energy Trust. On February 17, 2016, Argent Trust and its Canadian and United States holding companies (collectively "**Argent**") commenced proceedings under the *Companies' Creditors Arrangement Act* ("**CCAA**") for a stay of proceedings until March 19, 2016. On the same date, Argent filed voluntary petitions for relief under Chapter 15 of the *United States Bankruptcy Code* ("**Chapter 15**"). On March 9, 2016, the stay of proceedings under the CCAA was extended until May 17, 2016. Additionally on March 10, 2016 the U.S. Bankruptcy Court approved an order recognizing the CCAA as the foreign main proceedings under Chapter 15. Mr. Brussa resigned on June 30, 2016.

Mr. Brussa resigned as a director of Twin Butte Energy Ltd. ("**Twin Butte**") on September 1, 2016. On September 1, 2016, the senior lenders of Twin Butte (the "**Senior Lenders**") made an application to the Court of Queen's Bench of Alberta (the "**Court**") to appoint a receiver and manager over the assets, undertakings and property of Twin Butte under the *Bankruptcy and Insolvency Act* (Canada) and trading in the common shares of Twin Butte was suspended by the Toronto Stock Exchange. On September 1, 2016, the Senior Lenders were granted a receivership order by the Court.

Mr. Brussa was a director of Virginia Hills Oil Corp. ("**VHO**"), a TSX-V listed oil and gas company. On February 13, 2017, VHO received a demand notice and notice of intention to enforce security from its lenders and agreed to consent to the early enforcement of the lenders' security and the appointment of a receiver over all of the current and future assets, undertakings and properties of VHO. The receiver was appointed on February 13, 2017. Mr. Brussa resigned as a director of VHO on February 24, 2017.

Penalties or Sanctions

To Crew's knowledge, other than as disclosed herein, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Crew will be subject to in connection with the operations of Crew. In particular, certain of the directors and officers of Crew are or may be involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with Crew or with entities which may, from time to time, provide financing to, or make equity investments in, Crew's competitors. In accordance with ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Crew are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract.

AUDIT COMMITTEE INFORMATION

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

The Audit Committee of Crew is composed of the following members:

Name	Independent	Financially Literate	Relevant Education and Experience
David G. Smith	Yes	Yes	Mr. Smith is Chief Executive Officer and a Director (previously President and Chief Executive Officer) of Keyera Corp., previously Keyera Facilities Income Fund, a public energy infrastructure company. Prior to that he was Executive Vice President, Liquids Business Unit and prior to that Executive Vice President and Chief Financial Officer and Corporate Secretary of Keyera Facilities Income Fund and its predecessor companies from June 1998 until May, 2011. Previously Mr. Smith was employed with Gulf Canada Resources Limited and Imperial Oil Limited, and he has more than 35 years of experience in the oil and gas industry. Mr. Smith holds a Bachelor of Mathematics degree from the University of Waterloo, a Master of Business Administration degree from Harvard University and the ICD.D designation from the Institute of Corporate Directors.
Dennis L. Nerland, Q.C.	Yes	Yes	Mr. Nerland is a lawyer practicing primarily in the area of tax and estate planning. Mr. Nerland has been a partner of Nerland Lindsey LLP (formerly Shea Nerland Calnan LLP) since 1990 and was a partner at Burnet, Duckworth & Palmer LLP prior thereto. Mr. Nerland is a member of the Law Society of Alberta, the Canadian Tax Foundation, the Calgary Bar Association, and the Society of Trusts and Estates Practitioners. Mr. Nerland is also a director of a number of public and private companies. Mr. Nerland has completed the Rotman/Haskayne Directors Education Program and achieved the ICD.D designation and has also successfully completed the Rotman Financial Literacy Program.
Ryan Shay	Yes	Yes	Mr. Shay has over 20 years of experience in the oil and gas industry and was Managing Director, Head of Investment Banking at Cormark Securities Inc. until he retired therefrom in June 2016. Mr. Shay was a member of Cormark's Executive Committee, Risk Committee, Capital Markets Committee, Compensation Committee, Compliance Committee and Audit Committee. Mr. Shay joined Cormark in 1999 as an Energy Research Analyst and was promoted to the Executive Committee of the firm in 2000. He transitioned careers from Research to Investment Banking in 2007 and was promoted to Co-Head of Investment Banking in 2010 and Head of Investment Banking in 2013. Mr. Shay began his career in the investment industry with Peters & Co. Limited in 1996, earning his Chartered Financial Analyst designation in 1999 and was formerly with Deloitte & Touche in 1993, earning his Chartered Accountant designation in 1996. Mr. Shay received his Bachelor of Commerce from the University of Saskatchewan and graduated with Great Distinction. Mr. Shay also sits on the Board and is a member of the Audit Committee of Perpetual Energy Inc. and Journey Energy Inc., both publicly listed TSX issuers.

Pre-Approval of Policies and Procedures

Crew has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP: The Audit Committee approves a schedule which summarizes the services to be provided that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the Audit Committee, may cover a shorter or longer period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of the Corporation's management to make a judgment as to whether a proposed service fits within the pre-approved services. Services that arise that were not contemplated in the schedule must be pre-approved by the Audit Committee chairman or a delegate of the Audit Committee. The full Audit Committee is informed of the services at its next meeting.

Crew has not approved any non-audit services on the basis of the de minimis exemptions. All non-audit services are pre-approved by the Audit Committee in accordance with the pre-approval policy referenced herein.

The following table provides information about the fees billed to Crew and its subsidiaries for professional services rendered by KPMG LLP, the Corporation's external auditors, during fiscal 2019 and 2018:

	Aggregate fees billed ($)	
	2019	2018
Audit fees	242,000	243,950
Audit-related fees	-	-
Tax fees	22,350	26,055
All other fees	55,000	54,500
	319,350	324,500

Audit Fees. Audit fees consist of fees for the audit of Crew's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related services include audit and review of certain subsidiaries and financial aspects.

Tax Fees. Tax fees included tax planning and various taxation matters.

All Other Fees. Other services provided by Crew's external auditor other than audit, audit-related and tax services.

HUMAN RESOURCES

Crew currently employs 71 full-time employees, of which 57 are located in the head office along with two contractors and 12 are field employees. Crew intends to add additional professional and administrative staff as the need arises.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations do not affect the Corporation's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although laws and regulations are a matter of public record, the Corporation is unable to predict what additional legislation or amendments governments may enact in the future.

The Corporation holds interests in crude oil, NGL and natural gas properties, along with related assets, primarily in the Canadian provinces of British Columbia, Saskatchewan and Alberta. The Corporation's assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of the Corporation's upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil, NGL and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

Negotiations between buyers and sellers determine the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Condensate and Other Natural Gas Liquids

The pricing of condensates and other NGL such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGL, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGLs from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required;

however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("**Cabinet**") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Corporation does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGL outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGL in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government’s jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government’s duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGL, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, construction continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's Indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies.

On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision quashing the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019, and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**"), would commence in the first half of 2019, pre-construction work was halted in late 2018 when a U.S. Federal Court Judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometres of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020.

Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometre long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGL products in excess of 12,500 metric tonnes to or from British Columbia's north coast. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents. On February 11, 2010, the Government of Alberta announced that it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2020, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits, following two derailments that led to fires and oil spills in Saskatchewan. These reduced speed limits will remain in effect until April 1, 2020.

Natural Gas

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and restricted access to storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada was further exacerbated by restricted access to natural gas storage. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network, (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States Natural Gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project, which will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, BC, via the Coastal GasLink pipeline, which will be built and operated by TC Energy's subsidiary Coastal GasLink ("**CGL**") (the "**CGL Pipeline**"). Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell 65% of its interest in the CGL Pipeline, to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction is expected to close in the first half of 2020. The CGL Pipeline's route was altered as a result of feedback that LNG Canada received from Indigenous groups in the area, and on May 1, 2019, the British Columbia Oil and Gas Commission (the "**BC Commission**") approved the current planned route for the CGL Pipeline. However, the CGL Pipeline has faced intense opposition. For example, a challenge to the approval process of the CGL Pipeline was launched in August 2018, contending that it should have been subject to the federal review instead of a provincial review. In July 2019, the NEB confirmed that the CGL Pipeline was properly subject to provincial jurisdiction. In addition, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays of construction activities on the CGL Pipeline. Coastal Gaslink Pipeline Ltd. obtained an injunction on December 31, 2019, and enforcement of the injunction started in February 2020.

On February 19, 2020, the British Columbia Environmental Assessment Office (the "**EAO**") directed CGL to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area.

In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the Curtailment Rules, as amended effective October 1 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbl/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint venturers may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for December 2019, January 2020 and February 2020 is set at 3.81 million bbls/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta. The *Curtailment Rules* are set to be repealed by December 31, 2020.

The Corporation is not subject to a curtailment order.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "**CUSMA**". Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the USMCA. According to Bill C-4, the USMCA will come into force two months after the House of Commons and the Senate pass Bill C-4. Until then, NAFTA remains the North American trade agreement currently in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced. It is possible that the USMCA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and ten other countries have agreed on the text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam and Singapore. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil, NGL and natural gas pursuant to mineral rights owned by the respective provincial governments. Oil and natural gas leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are typically calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGL.

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totalling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue 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 *Royalty Guarantee Act (Alberta),* came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their 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/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the Alberta Energy Regulator (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 of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all 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 towards a minimum of 5% 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.

Oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly, and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014, and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

The Old Framework is applicable to all conventional crude 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 crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. 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%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGL is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

British Columbia

Producers of crude oil in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was located. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGL in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGL and natural gas by-products. For natural gas, the royalty rate can range from 3% up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGL and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will therefore vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGL is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale from $1.25 to $4.94 per hectare depending on the total number of hectares owned by the entity.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. Additionally, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of $1.50 per acre owned regardless of whether or not there is production from the lands.

In addition to such surcharges and taxes, the Crown royalty rate payable in respect of crude oil, depends on a number of variables including, the type and vintage of crude oil, the quantity of crude oil produced in a month, the average wellhead price and certain price adjustment factors determined monthly by the provincial government. This means that producers may pay varying royalties each month, depending on monthly production, governmental price adjustments and the underlying characteristics of the producer's assets. Where production equals the relevant reference well production rate, the minimum Crown royalty rate payable ranges from 5% to 20% and the maximum royalty rate payable ranges from 30% to 45%, depending on the classification of the crude oil, the average wellhead price and subject to applicable deductions.

The amount payable as a Crown royalty in respect of production of natural gas and NGL is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

For production from freehold lands, producers must pay a freehold production tax, determined by first determining the Crown royalty rate, and then subtracting a calculated production tax factor. Depending on the classification of the petroleum substance produced, this subtraction factor may range between 6.9 and 12.5, however, in certain circumstances, the minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the Western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the Western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

Where oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Regulatory Authorities and Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas (“**GHG**”) emissions, including carbon dioxide equivalents ("**CO2e**"), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On August 28, 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* ("**IAA**") came into force and the NEB Act and the *Canadian Environmental Assessment Act*, *2012* ("**CEAA 2012**") were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

"Designated projects" under the IAA include interprovincial or international pipelines that require more than 75km of new right of way, and will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The impact assessment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75km of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for non-designated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is no certainty that the changes brought about by Bill C-69 will result in projects being approved on a timely basis. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

On May 12, 2017, the federal government introduced the Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the *Oil Tanker Moratorium Act*, which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53’00’’ north latitude and west of 126°38’36’’ west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related legislation including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented. These regional plans may affect further development and operations in such regions.

The AER monitors seismic activity across Alberta, in the context of assessing the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing is an important and common practice to stimulate production of oil and gas from dense subsurface rock formations. The process involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

In an ongoing process spanning from February 19, 2015 to December 9, 2019, the AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place that are aimed at limiting the impact and potential of induced earthquakes from hydraulic fracturing are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). The Corporation does not currently operate in any of these locations.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**B.C. Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the B.C. Commission to consider these environmental objectives in deciding whether or not to authorize a crude oil or natural gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Beginning in 2015, the British Columbia Government has introduced a regime to monitor and manage the risk of seismicity induced by the oil and natural gas industry, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation*, as amended in June 2015 requires and oil and gas producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BC Commission before resuming production. In June 2016, the BC Commission amended the permitting process to require all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BC Commission issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek (the "**Kiskatinaw Area**"). Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is submitted to the BC Commission, and notifying the BC Commission and local residents about planned hydraulic fracturing operations. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BC Commission on demand. If a seismic event occurs, permit holders are subject to a defined reporting system that sets thresholds on the Richter scale of seismic magnitude and obliges permit holders to employ mitigation practices in the event of seismicity above those thresholds . The obligations range from reporting the seismic event and developing an approved protocol to mitigate against subsequent seismicity, to initiating such protocols, to suspending operations until permitted to resume by the BC Commission. The BC Commission monitors Natural Resources Canada's reporting of seismicity across the province, and has installed additional seismograph stations in northeast British Columbia. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

The British Columbia Government passed *Bill 51 – 2018: Environmental Assessment Act* in late 2018, which will replace the environmental assessment regime that has been in place since 2002. The updated *Environmental Assessment Act* came into force on December 16, 2019. The amendments will subject proposed projects to an enhanced environmental review process similar in substance to the federal environmental assessment process. The new environmental assessment process aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building, in alignment with British Columbia's recent passage of Bill 41, which affirmed and adopted the United Nations Declaration on the Rights of Indigenous Peoples. Simultaneously with the enactment of the *Environmental Assessment Act*, the British Columbia Government enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project. However, many details of the new assessment process remain unknown, but the British Columbia Government has released a proposed timetable for the release of supplementary and informational materials through 2020.

In 2018, the British Columbia Government proposed amendments to the BC EMA that would see new heavy oil imports, whether by rail, expanded pipeline, or otherwise, managed through a discretionary permitting process (the "**Proposed Amendments**"). The Proposed Amendments would directly affect the transport of heavy oil blends across British Columbia to tidewater through the Trans Mountain Pipeline. In its unanimous decision, the *Reference Re Environmental Management Act (British Columbia)* delivered May 24, 2019; the British Columbia Court of Appeal held that the Proposed Amendments are unconstitutional. The Supreme Court of Canada heard British Columbia's appeal on January 16, 2020, and found that, constitutionally, the British Columbia Government does not have the jurisdiction to make the Proposed Amendments. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. On January 29, 2020, the Government of British Columbia acknowledged that Canada's highest court has ruled in support of the Trans Mountain Pipeline expansion proceeding, and indicated that the Government of British Columbia would not initiate further challenges against the Trans Mountain Pipeline.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources is the primary regulator of crude oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the "**SKOGCA**") is the act governing the regulation of resource development operations in the province along with *The Oil and Gas Conservation Regulations, 2012* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The aim of the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. The Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petrinex Database.

Liability Management Rating Program

Alberta

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect the Corporation's ability to obtain or transfer licenses.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program, including the Corporation, fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation (Re)* ("**Redwater**"), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licencee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission System. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Participants seeking the program incentives must commit to an active liability reduction target to be met through closure work of inactive assets. The Corporation is not participating in the voluntary ABC program due to the Company's limited decommissioning liability exposure in Alberta.

British Columbia

Similar to Alberta, the B.C. Commission oversees a Liability Management Rating Program (the "**B.C. LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the B.C. LMR Program, the B.C. Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

As a result of certain amendments to the OGAA, on April 1, 2019 a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the regulated amount of the levy, calculated using each permit holder's proportionate share of the total liabilities of all permit holders required to contribute to the fund. The OGAA permits the B.C. Commission to impose more than one levy in a given calendar year.

Effective May 31, 2019, the *Dormancy and Shutdown Regulation* (the "**Dormancy Regulation**") establishes the first set of legally imposed timelines for the restoration of oil and natural gas wells in Western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between

2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BC Commission, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in an annual work plan.

Saskatchewan

The Saskatchewan Ministry of Energy and Resources administrates the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when the Saskatchewan Ministry of Energy and Resources confirms there is no legally responsible or financially able party to deal with the abandonment and/or reclamation responsibilities. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. On August 19, 2016, the Saskatchewan Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Saskatchewan Ministry of the Economy announced that it considers all licence transfer applications non-routine as the Ministry does not strictly rely on the standard LLR calculation in evaluating deposit requirements. In addition to increased security deposit requirements, the Saskatchewan Ministry of the Economy at that time announced in 2016 that it may incorporate additional conditions with licence transfer approvals.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada.

The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

Six provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories. The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal fuel charge regime took effect in Alberta on January 1, 2020.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and the Court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

Finally, the federal government has also enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999*, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The *Carbon Competitiveness Incentives Regime* (the "**CCIR**"), remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed *Technology Innovation and Emissions Reduction* ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020. The TIER regulation operates differently than the former facility -based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. . In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO2 emissions from oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia’s net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, the Government raised the carbon tax to $35/tonne in April 2018 and subsequently raised it to $40/tonne on April 1, 2019. The Government of British Columbia intends to continue raising its carbon tax in $5 increments until it reaches $50/tonne in 2021.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the “**GGIRCA**”) came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

On December 5, 2018, the Government of British Columbia announced an updated clean energy plan, “**CleanBC**”, which seeks to ensure that British Columbia achieves 75% of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation construction, and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15% renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (iv) investing in the electrification of oil and gas production; (v) reducing 45% of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles. The 2019 provincial budget provided $902 million over three years to support CleanBC, including electric vehicle rebates, incentives for making homes and businesses more energy efficient, and an enhanced climate action tax credit. On January 16, 2019, the B.C. Commission announced a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. These new rules came into effect on January 1, 2020.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation. Subsequently, the Government released *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy* outlining its strategy to reduce GHG emissions by 12 million tonnes by 2030.

The MRGGA, which is partially compliant with the federal emissions trading system, was partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. An amended version of the MRGGA was proclaimed in full in December 18, 2018, establishing the framework of an output-based emissions management framework.

Under the MRGGA, facilities that have annual GHG emissions in excess of 50,000 tonnes are regulated to meet the province's reduction targets. The following regulations were enacted throughout 2018: *The Management and Reduction of Greenhouse Gases (General and Electricity Producer) Regulations*, the *Management and Reduction of Greenhouse Gases (Reporting and General) Regulations*, and *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations*. These Regulations establish reporting requirements and impose various emissions limits for those emitters that fall within the program. On January 1, 2019, *The Oil and Gas Emissions Management Regulations* (the "**Saskatchewan O&G Emissions Regulations**") came into effect. The Saskatchewan O&G Emissions Regulations apply to licensees of oil facilities that may generate more than 50,000 tonnes of CO2e per year, obliging each licensee to propose an emissions reduction plan in accordance with an annual emissions limit with the goal of achieving annual emissions reductions of 40 to 45% by 2025. The Saskatchewan O&G Emissions Regulations aim to achieve 4.5 million tonne CO2e reduction in emissions by 2025, and a total reduction of 38.2 million tonnes CO2e between 2020 and 2030.

On April 10, 2019, Saskatchewan produced the first annual report on climate resilience. The report measures the Province's progress on goals set out under *Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy*. Among these goals is the aim of increasing the role of renewable energy in the provincial energy mix to 50% by 2030.

On October 1, 2019, *Bill 147 – An Act to amend The Oil and Gas Conservation Act*, was proclaimed into force that, in part, amends the SKOGCA to the extent necessary to bring it into alignment with the Saskatchewan O&G Emissions Regulations discussed above.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally. Crew's business could also be affected by additional risks and uncertainties not currently known to the Corporation or that it currently deems to be immaterial. If any of these risks actually occur, it could materially harm Crew's business, financial condition, results of operations, cash flows or impair the Corporation's ability to implement business plans or complete development activities as scheduled. In that case, the market price of the Common Shares could decline and you could lose all or part of your investment.

Before deciding whether to invest in any Common Shares, investors should consider carefully the risks set out below. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations.

The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled Forward-Looking Statements.

Exploration, Development and Production Risks

The Corporation's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil, NGL and natural gas.

Future oil, NGL and natural gas exploration may involve unprofitable efforts from dry wells or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, the Corporation may explore for and produce sour gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance and business interruption insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Risk Factors – Insurance"*. In either event, the Corporation could incur significant costs.

Weakness and Volatility in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and natural gas industry may affect the value of the Corporation's reserves, and restrict its cash flow and ability to access capital to fund the development of its properties

Market events and conditions, including global excess oil and natural gas supply, recent actions or inaction taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), recent announcements by Saudi Arabia to relax quotas and resulting price wars, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment and the continuing impact of the Coronavirus ("**COVID-19**"), have caused significant weakness and volatility in commodity prices. See "*Risk Factors – Political Uncertainty*". These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Risk Factors –Royalties and Incentives", "Risk Factors –Regulatory Authorities and Environmental Regulation*" and "*Risk Factors –Climate Change Regulation*" in these Risk Factors. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year-over-year basis. See "*Risk Factors - Reserves Estimates*". Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. See "*Risk Factors - Credit Facilities*". In addition to possibly decreasing the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil, NGL and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms. See "*Risk Factors –Additional Funding Requirements*". If these conditions persist, the Corporation's cash flow may not be sufficient to continue to fund its operations and to satisfy its obligations when due, and the Corporation's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to the Corporation or at all. Similarly, there can be no assurance that the Corporation will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge its obligations and continue as a going concern.

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil, NGL and natural gas, affecting net production revenue, production volumes and development and exploration activities

The Corporation's ability to market its oil, NGL and natural gas may depend upon its ability to acquire capacity in pipelines that deliver oil, NGL and natural gas to commercial markets or contract for the delivery of crude oil by rail. Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by the Corporation, including:

- deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, and processing and storage facilities;

- operational problems affecting pipelines, railway lines and processing and storage facilities; and

- government regulation relating to prices, taxes, royalties, land tenure, allowable production, and the export of oil and natural gas and many other aspects of the oil and natural gas business.

Oil, NGL and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply of, and demand for, these commodities due to the impact of COVID-19, the current state of the world economies, shale oil production in the United States, the OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts, in the Middle East and ongoing credit and liquidity concerns. Prices for oil, NGL and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

Any substantial and extended decline in the price of oil, NGL and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

Volatile oil, NGL and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil, NGL and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for, and project the return on, acquisitions and development and exploitation projects.

Market Price

The trading price of the Corporation's Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the oil and natural gas market and worldwide pandemics such as COVID-19. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions institutions including government-sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the common shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the common shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and the Corporation may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions.

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and the resources required to provide such services. In this regard, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the market conditions for such non-core assets, certain non-core assets of the Corporation may realize less on disposition than their carrying value on the financial statements of the Corporation.

Political Uncertainty

The Corporation's business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration has withdrawn the United States from the Trans-Pacific Partnership and the United States Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected competitiveness of other jurisdictions, including Canada. In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In January 2020, the Canadian Parliament tabled Bill C-4 which, once proclaimed into force, will ratify the USMCA. The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force. See "*Industry Conditions - The North American Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Corporation.

The terms of the United Kingdom's exit from the European Union and whether it will occur at all remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of its Common Shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project. Though the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia in January 2020, tensions remain high between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction where the Corporation is active. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Lack of political consensus, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt the Corporation's activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas*".

Operational Dependence

The successful operation of a portion of the Corporation's properties is dependent on third parties

On a limited basis, other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on the Corporation's financial and operational results. See "*Industry Conditions – Liability Management Rating Program*" and "*Risk Factors – Third Party Credit Risk*".

Project Risks

The success of the Corporation's operations may be negatively impacted by factors outside of its control resulting in operational delays and cost overruns

The Corporation manages a variety of small and large projects in the conduct of its business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and market oil, NGL and natural gas depends upon numerous factors beyond the Corporation's control, including:

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;

- availability and productivity of skilled labour; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation may be unable to execute projects on time, on budget, or at all.

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on the Corporation's ability to produce and sell its oil, NGL and natural gas

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil, NGL and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities, continues to affect the oil and natural gas industry and limits the ability to transport produced oil, NGL and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway. See "*Industry Conditions – Transportation Constraints and Market Access* " and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas, and could result in the Corporation's inability to realize the full economic potential of its products or in a reduction of the price offered for the Corporation's production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals of major projects is unclear.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Corporation's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Competition

The Corporation competes with other oil and natural gas companies, some of which have greater financial and operational resources

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil, NGL and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil, NGL and natural gas, but also carry on refining operations and market oil, NGL and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil, NGL and natural gas include price, process, and reliability of delivery and storage.

Cost of New Technologies

The Corporation's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to implement and benefit from technological advantages. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If the Corporation does implement such technologies, there is no assurance that the Corporation will do so successfully. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. If the Corporation is unable to utilize the most advanced commercially available technology, or is unsuccessful in implementing certain technologies, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Corporation's financial condition, results of operations and cash flow

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flow by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil, NGL and natural gas and/or increase the Corporation's costs and/or delay planned operations

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*", "*Industry Conditions – Curtailment" and "Risk Factors – Liability Management".*

In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its common shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See *"Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Program".*

Royalty Regimes

Changes to royalty regimes may negatively impact the Corporation's cash flows

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. See "*Industry Conditions – Royalties and Incentives*".

Hydraulic Fracturing

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

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil, NGL and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil, NGL and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil, NGL and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil, NGL and natural gas that the Corporation is ultimately able to produce from its reserves.

British Columbia

Due to seismic activity recorded in the Kiskatinaw Seismic Monitoring and Mitigation area (the "**Kiskatinaw Area**", in May 2018, the BC Commission issued special notification and monitoring requirements for hydraulic fracturing operators in the Kiskatinaw Area. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations; pre-operation notification to both residents and the BC Commission and the suspension of operations if a seismic event above 3.0 magnitude occurs. On November 29, 2018, hydraulic fracturing operations of a natural gas producer in the Montney area in British Columbia were suspended after a series of three seismic events, ranging from 3.4 to 4.5 in magnitude, were linked to hydraulic fracturing by the BC Commission. Though the BC Commission allowed the natural gas producer to resume operations in the Montney area on October 21, 2019, this suspension demonstrates the BC Commission's willingness to enforce its enhanced regulatory requirements. The same natural gas producer was also suspended from using a wastewater disposal well in 2019 due to seismicity attributed to the use of that well, demonstrating that the BC Commission's monitoring and oversight of seismic risk is not limited to hydraulic fracturing.

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. The panel's recommendations included directing the Government of British Columbia to consider classifying hydraulic fracturing wastewater as hazardous waste, certain best practices for producers conducting hydraulic fracturing and increased water and seismicity monitoring by the BC Commission in northeastern British Columbia. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect the Corporation's business operation, financial condition, results of operations and prospects.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for dams companies have built in association with their hydraulic fracturing operations. Under the *Water Sustainability Act*, dams require a water licence. For dams over a certain size, dam-operators must comply with additional safety and reporting requirements set out in the *Dam Safety Regulation*. Larger dams are also subject to an environmental assessment and approval under the *Environmental Assessment Act*. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the requisite regulatory authorization. While the BC Commission has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent the relevant industry regulators will respond to this issue. The Corporation may face operational delays depending on the level of severity with which the overseeing regulatory authorities decide to address these unauthorized projects, particularly where the Corporation is not strictly complying with the current regulatory framework.

Disposal of Fluids Used in Operations

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

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

Environmental

Compliance with environmental regulations requires the dedication of a portion of the Corporation's financial and operational resources

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

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

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil, NGL and natural gas, the Corporation's operating expenses and may impair the Corporation's ability to compete

Countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil, NGL and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition.

Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Corporation's ability to acquire properties or require a substantial cash deposit with the regulator

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Changes to the Liability Management Rating Program (the "**AB LMR Program**") administered by the AER, or other changes to the requirements of liability management programs, may result in significant increases to the Corporation's compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in *Redwater Energy Corporation (Re)* ("**Redwater**") on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Climate change may pose varied and far ranging risks to the business and operations of the Corporation, both known and unknown, that may adversely affect the Corporation's business, financial condition, results of operations, prospects, reputation and share price

Chronic Climate Change Risks

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases ("**GHG**") which may require the Corporation to comply with federal and/or provincial greenhouse gas emissions legislation . Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. See "*Risk Factors – Seasonality*". In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require the Corporation to incur greater expenditures (time and capital) to deal with the challenges posed by such changes to its premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, the Corporation may not be able to, or will incur greater costs to, carry out hydraulic fracturing operations.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, ENvironment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term, potentially reducing the demand for oil, NGL and natural gas production resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or requiring asset impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*", "*Risk Factors – Non-Governmental Organizations",* "*Risk Factors – Reputational Risk Associated with the Corporation's Operations*" and "*Risk Factors – Changing Investor Sentiment*".

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and forest fires may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are located in locations that are proximate to forests and rivers and as such a forest fire or flood may lead to significant downtime and/or damage to such assets.

Moreover, extreme weather conditions may lead to disruptions in the Corporation's ability to transport produced oil and natural gas as well as goods and services in its supply chain.

Seasonality

Oil and natural gas operations are subject to seasonal weather conditions and the Corporation may experience significant operational delays as a result

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable which prevents, delays or makes operations more difficult. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. Certain of the Corporation's 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 impassable muskeg.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Corporation's financial condition

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil, NGL and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results**.**

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of the common shares of the Corporation.

To the extent that the Corporation engages in risk management activities related to foreign exchange and interest rates, there is a credit risk associated with counterparties with which the Corporation may contract.

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations and acquire and develop reserves

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil, NGL and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

See "*Industry Conditions – Royalties and Incentives*".

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or the affecting of, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including the Corporation, to access additional financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing Shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation may require additional financing from time to time to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and, from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, or the cost of, additional financing.

As a result of global economic and political conditions and the domestic lending landscape, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil, NGL and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing Shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Current conditions in the oil and natural gas industry have had a negative impact on the ability of oil and natural gas companies in Canada to access additional financing and has increased the cost of existing financing.

Credit Facility Arrangements

Failing to comply with covenants under the Corporation's credit facility could result in restricted access to additional capital or being required to repay all amounts owing thereunder

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. The Corporation's current credit facility does not include financial ratio tests.

In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others**.** As the Corporation's credit facilities are a demand facilities, the lenders may demand repayment by the Corporation at any time.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices have recently increased they remain volatile as a result of various factors including limited egress options for Western Canadian oil and natural gas producers, actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

The Supreme Court of Canada's decision in Redwater has given rise to new covenants and restrictions under the Corporation's credit facilities, should LMR levels fall below existing agreed-upon thresholds. The Corporation is also required to provide additional reporting to its lenders regarding its existing and/or budgeted abandonment and reclamation obligations, its decommissioning expenses, its LMR and/or any notices or orders received from an energy regulator in any applicable province. *See "Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs".*

If the Corporation's lenders require repayment of all or a portion of the amounts outstanding under its credit facilities for any reason, including for a default of a covenant or the reduction of a borrowing base, there is no certainty that the Corporation would be in a position to make such repayment. Even if the Corporation is able to obtain new financing in order to make any required repayment under its credit facilities, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under its credit facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

Increased debt levels may impair the Corporation's ability to borrow additional capital on a timely basis to fund opportunities as they arise

From time to time, the Corporation may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

Hedging activities expose the Corporation to the risk of financial loss and counter-party risk

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil, NGL and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil, NGL and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Availability and Cost of Material and Equipment

Restrictions on the availability and cost of materials and equipment may impede the Corporation's exploration, development and operating activities

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede the Corporation's exploration, development and operating activities.

Diluent Supply

A decrease in, or restriction in access to, diluent supply may reduce the Corporation's revenue

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent, or a restriction in access to diluent, may cause its price to increase, increasing the cost to transport heavy oil and bitumen to market. An increase to the cost of bringing heavy oil to market may increase the Corporation's overall operating cost and result in decreased net revenues negatively impacting the overall profitability of the Corporation's heavy oil.

Title to and Right to Produce from Assets

Defects in the title or rights to produce the Corporation's properties may result in a financial loss

The Corporation's actual title to and interest in its properties, and its right to produce and sell the oil, NGL and natural gas therefrom, may vary from the Corporation's records. In addition, there may be valid legal challenges or legislative changes that affect the Corporation's title to and right to produce from its oil, NGL and natural gas properties, which could impair the Corporation's activities and result in a reduction of the revenue received by the Corporation.

If a defect exists in the chain of title or in the Corporation's right to produce, or a legal challenge or legislative change arises, it is possible that the Corporation may lose all, or a portion of, the properties to which the title defect relates and/or its right to produce from such properties. This may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserves Estimates

The Corporation's estimated reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Corporation

There are numerous uncertainties inherent in estimating reserves, and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil, NGL and natural gas reserves (including the breakdown of reserves by product type) and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil, NGL and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil, NGL 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. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil, NGL and natural gas, curtailments or increases in consumption by oil, NGL and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil, NGL and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

Insurance

Not all risks of conducting oil and natural gas opportunities are insurable and the occurrence of an uninsurable event may have a materially adverse effect on the Corporation

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blowouts, leaks of sour gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Non-Governmental Organizations

The Corporation's properties may be subject to action by non-governmental organizations or terrorist attack

The oil, NGL and natural gas exploration, development and operating activities conducted by the Corporation may, at times, be subject to public opposition. Such public opposition could expose the Corporation to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. See "*Industry Conditions – Transportation Constraints and Market Access*". There is no guarantee that the Corporation will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require the Corporation to incur significant and unanticipated capital and operating expenditures.

Reputational Risk Associated with the Corporation's Operations

The Corporation relies on its reputation to continue its operations and to attract and retain investors and employees

The Corporation's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Corporation or as a result of any negative sentiment toward, or in respect of the Corporation's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Corporation operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Corporation's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which the Corporation has no control. Similarly, the Corporation's reputation could be impacted by negative publicity related to, loss of life, injury or damage to property and environmental damage caused by the Corporation's operations. In addition, if the Corporation develops a reputation of having an unsafe work site, this may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact the Corporation's reputation. See *"Risk Factors – Climate Change".*

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Corporation's reputation. Damage to the Corporation's reputation could result in negative investor sentiment towards the Corporation, which may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities.

Changing Investor Sentiment

Changing investor sentiment towards the oil and natural gas industry may impact the Corporation's access to, and cost of, capital

A number of factors, including the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural gas properties or companies, or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from the Board of Directors, management and employees of the Corporation. Failing to implement the policies and practices, as requested by institutional investors, may result in such investors reducing their investment in the Corporation, or not investing in the Corporation at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry and more specifically, the Corporation, may result in limiting the Corporation's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Corporation's securities even if the Corporation's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Corporation's asset which may result in an impairment change.

Dilution

The Corporation may issue additional Common Shares, diluting current Shareholders

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Management of Growth

The Corporation may not be able to effectively manage the growth of its business

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. If the Corporation is unable to deal with this growth, it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

The Corporation or its working interest partners may fail to meet the requirements of a licence or lease, causing its termination or expiry

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease and the associated abandonment and reclamation obligations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation does not pay dividends and there is no assurance that it will do so in the future

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, cash flow, results of operations, financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations, as the Board of Directors considers relevant.

Litigation

The Corporation may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Corporation and its reputation

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

Indigenous Claims

Indigenous claims may affect the Corporation

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

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Corporation's competitive advantage or put it at risk of litigation

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

Taxation authorities may reassess the Corporation's tax returns

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Tax Act* and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Third Party Credit Risk

The Corporation is exposed to credit risk of third party operators or partners of properties in which it has an interest

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry, generally, and of the Corporation's joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Conflicts of Interest

Conflicts of interest may arise for the Corporation's directors and officers who are also involved with other industry participants

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the Business Corporations Act (Alberta) (the "**ABCA**") which require a director or officer of a corporation who is a party to, 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 to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *ABCA*. See "*Directors and Officers – Conflicts of Interest*".

Reliance on a Skilled Workforce and Key Personnel

An inability to recruit and retain a skilled workforce and key personnel may negatively impact the Corporation

The operations and management of the Corporation require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Corporation's business plans which could have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. The Corporation does not have any key personnel insurance in effect. Contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance If the Corporation is unable to: retain current employees; and/or recruit new employees with the requisite knowledge and experience, the Corporation could be negatively impacted. In addition, the Corporation could experience increased costs to retain and recruit these professionals.

The Corporation's workforce may be exposed to widespread pandemic

Crew's operations are located in areas relatively remote from local towns and villages and represent a concentration of personnel working and residing in close proximity to one another. Should an employee or visitor become infected with a serious illness that has the potential to spread rapidly, this could place Crew's workforce at risk. The 2020 outbreak of the novel coronavirus (COVID-19) around the world is one example of such an illness. The Corporation takes every precaution to strictly follow industrial hygiene and occupational health guidelines and pandemic management protocols are in place. The Corporation is following all government-mandated COVID-19 restrictions and advisories in order to keep its personnel safe and to avoid further spread of this pandemic. There can be no assurance that this virus or another infectious illness will not impact Crew's personnel and ultimately its operations.

Disruption and Dislocation Beyond the Corporation's Control

Natural Disasters, Terrorist Acts, Civil Unrest, Pandemics and Other Disruptions and Dislocations

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on Crew, its customers, and/or either of their businesses or operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses (including, most recently, the novel coronavirus (COVID-19), civil unrest (including the most recent protests and railway blockades in Canada) and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to Crew, its customers, and/or either of their businesses or operations.

Information Technology Systems and Cyber-Security

Breaches of the Corporation's cyber-security and loss of, or access to, electronic data may adversely impact the Corporation's operations and financial position

The Corporation has become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. The Corporation depends on various information technology systems to estimate reserve quantities, process and record financial data, manage the Corporation's land base, manage financial resources, analyze seismic information, administer contracts with operators and lessees and communicate with employees and third-party partners.

Further, 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. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or the Corporation's competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Corporation becomes a victim to a cyber phishing attack it could result in a loss or theft of the Corporation's financial resources or critical data and information or could result in a loss of control of the Corporation's technological infrastructure or financial resources. The Corporation's employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Corporation's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Corporation maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts cyber-security risk assessments periodically (approximately every second year). Despite the Corporation's efforts to mitigate such cyber -attacks through education and training, cyber-phishing activities remain a serious problem that could potentially damage its information technology infrastructure. The

Corporation applies technical and process controls in line with industry-accepted standards to protect its information, assets and systems. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation, and any damages sustained may not be adequately covered by the Corporation's current insurance coverage, or at all. 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.

Social Media

The Corporation faces compliance and supervisory challenges in respect of the use of social media as a means of communicating with clients and the general public

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Corporation's systems and obtain confidential information. The Corporation periodically reviews the web browsing history of its employees and contractors. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Corporation may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Expansion into New Activities

Expanding the Corporation's business exposes it to new risks and uncertainties

The operations and expertise of the Corporation's management are currently focused primarily on oil, NGL and natural gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas and may acquire different energy related assets as a result, the Corporation may face unexpected risks or alternatively, its exposure to one or more existing risk factors may be significantly increased, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information

Forward-Looking Information May Prove Inaccurate

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

Additional information on the risks, assumption and uncertainties are found under the heading " *Forward-Looking Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Crew is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of any legal proceeding, during the financial year ended December 31, 2019, nor is Crew aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10% of the current assets of Crew.

During the year ended December 31, 2019, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

TRANSFER AGENT AND REGISTRAR

Odyssey Trust Company, at its principal offices in Calgary, Alberta is the transfer agent and registrar of the Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), neither the Corporation or its Subsidiaries have entered into any material contracts within the last financial year, or before the last financial year that are still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than Sproule, the Corporation's independent engineering evaluator and KPMG LLP, the Corporation's auditors. As at the date hereof, the designated professionals of Sproule, as a group, beneficially owned, directly or indirectly less than 1% of Crew's outstanding securities, including securities of Crew's associates and affiliates, either at the time it prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. KPMG LLP are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans will be contained in the Corporation's information circular for the Corporation's next annual meeting of securityholders to be held on May 21, 2020. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for its most recently completed financial year. Alternatively, additional information relating to the Corporation is available on SEDAR at www.sedar.com.

For copies of Crew's information circular, comparative consolidated financial statements, including any interim consolidated comparative financial statements and additional copies of the Annual Information Form please contact:

Crew Energy Inc.
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T2P 0R4
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www.crewenergy.com

APPENDIX "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Crew Energy Inc. (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.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented below.

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 evaluator 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 evaluator on the reserves data; and

(c) the content and filing of this report.

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

DATED as of this 26th day of March, 2020.

(signed) "*Dale O. Shwed*"
Dale O. Shwed
President and Chief Executive Officer

(signed) "*John G. Leach*"
John G. Leach
Executive Vice-President and Chief Financial Officer

(signed) "*Jeffery E. Errico*"
Jeffery E. Errico
Director and Chairman of the Reserves Committee

(signed) "*John A. Brussa*"
John A. Brussa
Director and Member of the Reserves Committee

APPENDIX "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Crew Energy Inc. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's management and Board of Directors:

			Net Present Value of Future Net Revenue (before income taxes) (10% discount Rate)			
Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (County)	Audited (MM$)	Evaluated (MM$)	Reviewed (MM$)	Total (MM$)
Sproule Associates Limited	31-Dec-19	Canada	nil	**2,069**	Nil	**2,069**

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

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled "Evaluation of the P&NG Reserves of Crew Energy Inc. (As of December 31, 2019)".

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

EXECUTED as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada
February 3, 2020

(signed) "*Jason Robottom*"
Jason Robottom, P.Eng.
Manager, Reserves Certification

(signed) *"Kristian Wieclawek"*
Kristian Wieclawek, P. Eng.
Petroleum Engineer

(signed) "*Stephanie Brunt*"
Stephanie Brunt, P.Eng.
Petroleum Engineer

(signed) *"Liam O'Brien"*
Liam O'Brien, P. Eng.
Senior Petroleum Engineer

(signed) "*Victor Verkhogliad*"
Victor Verkhogliad, Ph.D, P.Geol.
Manager, Geoscience

(signed) "*Alexander Minev*"
Alexander Minev, P.Geol.
Senior Geologist

(signed) "*Cameron P. Six*"
Cameron P. Six, P.Eng.
CEO

(signed) "*Alec Kovaltchouk*"
Alec Kovaltchouk, P.Geo.
Vice-President, Geoscience

APPENDIX "C"
CREW ENERGY INC.
AUDIT COMMITTEE
MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Crew Energy Inc. ("**Crew**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Crew and related matters;

2. To provide better communication between directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) directors of Crew or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 — Audit Committees ("**NI 52-110**")) unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

2. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to Crew's internal control systems.

3. Review the annual and interim financial statements of Crew and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

- reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
- reviewing significant accruals, reserves or other estimates such as the impairment tests of financial and non-financial assets;
- reviewing accounting treatment of unusual or non-recurring transactions;
- ascertaining compliance with covenants under loan agreements;
- reviewing disclosure requirements for commitments and contingencies;
- reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
- reviewing unresolved differences between management and the external auditors; and
- obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Crew's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

- recommend to the Board the external auditors to be nominated;
- recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
- on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
- review and pre-approve any non-audit services to be provided to Crew or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Crew) their assessment of the internal controls of Crew, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Crew and its subsidiaries.

7. Review risk management policies and procedures of Crew (i.e. internal controls, hedging, litigation and insurance).

8. Establish a procedure for:

   - the receipt, retention and treatment of complaints received by Crew regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of Crew of concerns regarding questionable accounting or auditing matters.

9. Review and approve Crew's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Crew.

The Committee has authority to communicate directly with the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Crew. All employees of Crew are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Crew without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

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

7. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

8. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.