crew energy inc.

2022 ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2022

DATED AS AT **MARCH 8, 2023**

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas		Other	
bbl	barrel	**Mcfe**	thousand cubic feet equivalent	**AECO**	the natural gas storage facility located at Suffield, Alberta
Mbbl	thousand barrels	**Mmcf**	million cubic feet	**°API**	an indication of the specific gravity of crude oil measured on the API gravity scale
Mmbbl	million barrels	**Mcf/d**	thousand cubic feet per day	**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
bbl/d	barrels per day	**Mmcf/d**	million cubic feet per day	**BOE/d**	barrel of oil equivalent per day
BOPD	barrels of oil per day	**Mmbtu**	million British Thermal Units	**Mboe**	1,000 barrels of oil equivalent
NGL	natural gas liquids	**Bcf**	billion cubic feet	**M$**	thousands of dollars
Mcf	thousand cubic feet	**GJ**	Gigajoule	**MM$**	millions of dollars
		Tcf	trillion cubic feet	**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	To Convert From	To	Multiply By
Mcf	Cubic metres	28.174	Miles	Kilometres	1.609
Cubic metres	Cubic feet	35.494	Kilometres	Miles	0.621
bbl	Cubic metres	0.159	Acres (Alberta)	Hectares	0.400
Cubic metres	bbl oil	6.290	Hectares (Alberta)	Acres	2.500
Feet	Metres	0.305	Acres (British Columbia)	Hectares	0.405
Metres	Feet	3.281	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, capital expenditure plans and timing thereof, expected completion and on-stream dates, forward contracts and transportation commitments, hedging policies, abandonment and reclamation costs, tax horizon, exploration and development activities and production estimates; and under the heading "*Other Oil and Gas Information – Principal Properties*" as to our future development and infrastructure plans, strategy, timing, capital budget and associated guidance. 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 our 2023 capital expenditure program which remains 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: the continuing impact of the COVID-19 pandemic; 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; the impact of development of alternatives to, and changing demand for, petroleum producers; risks pertaining to supply chain issues and inflationary pressures; our reliance on hydraulic fracturing; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in climate change laws and other environmental regulations; potential regulatory and industry impacts stemming from the results of court actions affecting regions in which Crew holds assets; risks and uncertainties related to crude oil and natural gas interests and operations on Indigenous lands; 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 assumption that regulatory authorities in British Columbia will continue granting approvals for oil and gas activities relating to drilling, completions, testing, processing facilities, and production and transportation infrastructure in 2023 on time frames, and terms and conditions, consistent with past practice; 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) and 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;

"**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.

"**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 February 3, 2023, evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2022;

"**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); 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, 2022.

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."

As at December 31, 2022, and as at the date of this Annual Information Form, Crew has no subsidiaries.

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".

DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS

Business Plan and Growth Strategies

The Crew business plan is to create a sustainable and profitable corporation focused on the development of oil and gas assets in western Canada, while remaining sufficiently flexible to adapt to changing industry conditions. Crew is specifically focused on the development of assets within the vast Montney resource play in northeast British Columbia, where the Corporation's liquids-rich natural gas areas offer significant development potential over the long-term. The following are integral components of Crew's corporate strategy:

- Adhere to safe and environmentally responsible operations while remaining committed to sound environmental, social and governance ("**ESG**") practices, which underpin the Corporation's fundamental business tenets;
- Monitor 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, the issuance of new equity, issuance of new debt or repayment of existing debt with the proceeds of non-core asset dispositions and strong cash flow generation;
- Value and maintain an entrepreneurial culture to attract and retain high-quality staff;
- Evaluate all opportunities by following a disciplined methodology of integrating technical information with expected economic outcomes and risking the expected economic value of each opportunity according to the existing producing analogs in a particular area;
- Adopt evolving technology to optimize operations, improve efficiencies and reduce costs;
- Use 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 natural gas, oil 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; and
- Actively manage its portfolio of assets to take advantage of value-enhancing acquisitions and dispositions when market conditions permit.

Crew's management 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) risked return versus cost of capital; (v) strategic benefits to Crew; and (vi) 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 to develop a number of opportunities with balanced risk profiles and commodity exposure, as it pursues sustainable levels of profitable production and financial stability. Crew's plan is to focus on the development of its high quality Montney assets in northeast British Columbia while maintaining a strong financial position. Crew's size and asset base allow for capital expenditure curtailment 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 its financial position.

Crew has executed its strategy through exploration and development programs combined with both corporate and property acquisitions. The Corporation 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. Funding 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 equity issues.

Crew's management team has a demonstrated track record of bringing together the key components that form a successful exploration and production company, such as: 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.

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.

Crew's 2019 net capital expenditures[1] 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.

In 2020, Crew's net capital expenditures[1] totaled $28.1 million (after a net $58.2 million of asset dispositions net of acquisitions) as the Corporation executed a modest capital program, conservatively spending to maintain the Corporation's financial strength during a period of depressed commodity pricing and low adjusted funds flow which were driven in large part by the COVID-19 pandemic. The Corporation realized cost and operational improvements in the year that reduced drill times, generated strong capital efficiencies and enhanced returns. In 2020, the Corporation drilled a total of 15.0 net wells, including 12.0 net natural gas wells, 2.0 net heavy oil wells, 1.0 net water disposal well, and completed 10.0 net wells, including 8.0 net natural gas wells.

In 2021, Crew executed an expanded capital program as part of a two-year strategic development plan designed to expand margins and significantly improve leverage metrics by efficiently calibrating production volumes to match ongoing infrastructure and transportation commitments. Net capital expenditures[1] totaled $169.6 million (after $8.3 million of net asset dispositions), focused on continued development of the Corporation's Montney assets in northeast British Columbia with the drilling of 24.7 net wells and the completion of 22.7 net wells. The successful capital program contributed to annual average production of 26,443 boe per day, a 20% increase over 2020. Late in the third quarter of 2021, Crew completed the disposition of all of its Lloydminster heavy oil assets and operations (the "**Heavy Oil Disposition"**) for net cash proceeds of $8.3 million. The Heavy Oil Disposition comprised approximately 1,050 boe per day of primarily heavy oil production, representing approximately 4% of Crew's total production volumes at the time of disposition. The Heavy Oil Disposition contributed to a significant reduction in Crew's corporate operating costs, total GHG emissions intensity, and overall asset retirement obligation liabilities.

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[1] Non-IFRS measure. Refer to the section entitled "Non-IFRS and Other Financial Measures" contained within Crew's MD&A for the year ended December 31, 2022, on page 25, which is available on SEDAR at www.sedar.com, for additional disclosures relating to this non-IFRS measure.

Crew's active 2022 capital program continued the momentum of the 2021 program, bringing the above-mentioned two-year strategic development plan to completion. Net capital expenditures[1] totaled $46.6 million (after $129.8 million of net asset dispositions), focused on continued development of the Corporation's Montney assets in northeast British Columbia with the drilling of 17.0 net wells and the completion of 16.0 net wells, which contributed to annual average production of 33,277 boe per day. The resultant increases in production levels, adjusted funds flow[2] and free adjusted funds flow[1] drove significant debt repayment during the year, resulting in materially improved leverage metrics exiting 2022. On August 18, 2022, Crew completed the disposition of certain assets at Attachie and Portage in northeast British Columbia for gross proceeds, before customary adjustments, of $130 million (the "**Attachie Disposition**"). The Attachie Disposition comprised approximately 47,025 net acres of Montney rights on land north of the Peace River with no associated production or facilities. The net proceeds from the Attachie Disposition were used by Crew to redeem $128 million principal amount of outstanding 2024 Notes, which partial redemption was completed on September 19, 2022.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all of 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 crude 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 and remained highly volatile through 2019. In 2020, commodity price volatility was intensified by the impact of the COVID-19 pandemic on global commodity markets. Commodity pricing and industry activity strengthened significantly in the second half of 2020 through until the second half of 2022. In early 2023, downward commodity pricing pressure returned largely due to the impact of global supply and demand factors and geopolitical events. See *"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.

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[2] Capital management measure. Refer to the section entitled "Non-IFRS and Other Financial Measures" contained within Crew's MD&A for the year ended December 31, 2022, on page 25, which is available on SEDAR at www.sedar.com, for additional disclosures relating to this specified financial measure.

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 based on the Sproule Report. The effective date of the Statement is December 31, 2022 and the preparation date of the Statement was March 8, 2023. 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, 2022 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 province of British Columbia.

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, 2022

	RESERVES SUMMARY[1]							
	LIGHT CRUDE OIL & MEDIUM CRUDE OIL		NATURAL GAS LIQUIDS		CONVENTIONAL NATURAL GAS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mboe)	Net (Mboe)
PROVED								
Developed Producing	131	106	16,467	12,372	431,930	368,597	88,587	73,910
Developed Non-Producing	34	27	119	95	3,497	3,048	736	630
Undeveloped	2,463	1,917	23,833	18,250	571,575	496,506	121,559	102,918
TOTAL PROVED	2,628	2,049	40,420	30,717	1,007,002	868,150	210,882	177,458
TOTAL PROBABLE	5,530	4,093	28,641	20,727	773,792	653,730	163,136	133,775
TOTAL PROVED PLUS PROBABLE	8,158	6,142	69,061	51,443	1,780,795	1,521,882	374,018	311,232

Note:

(1) Columns may not add due to rounding.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE[1] 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	1,649,778	1,227,777	985,006	832,477	728,483	1,446,774	1,117,831	919,686	790,979	700,774
Developed Non-Producing	10,132	8,207	6,805	5,788	5,028	7,340	6,191	5,313	4,659	4,159
Undeveloped	2,367,956	1,380,264	909,673	647,147	483,259	1,723,380	996,854	648,270	454,080	333,364
TOTAL PROVED	4,027,866	2,616,248	1,901,485	1,485,412	1,216,770	3,177,494	2,120,877	1,573,269	1,249,718	1,038,298
TOTAL PROBABLE	4,092,132	1,940,081	1,132,952	751,723	542,880	2,984,582	1,408,359	817,449	540,164	389,635
TOTAL PROVED PLUS PROBABLE	8,119,998	4,556,329	3,034,436	2,237,135	1,759,649	6,162,075	3,529,236	2,390,718	1,789,882	1,427,933

Note:

(1) Columns may not add due to rounding.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2022

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	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	8,590,480	1,252,232	2,262,658	918,972	128,752	4,027,866	850,373	3,177,494
Total Proved Plus Probable	16,151,874	2,531,593	3,860,826	1,480,661	158,796	8,119,998	1,957,923	6,162,075

Note:

(1) Abandonment and reclamation costs ("**ARC**") are defined by NI 51-101 as all costs associated with the process of restoring Crew's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities. For more information, see "*Additional Information Relating to Reserves Data – Further Information Regarding Abandonment and Reclamation Costs*".

FUTURE NET REVENUE BY PRODUCT TYPE
AS OF DECEMBER 31, 2022

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]	40,084	7.55 per boe
	Conventional Natural Gas[2]	1,861,401	1.80 per Mcfe
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil[1]	160,383	9.67 per boe
	Conventional Natural Gas[2]	2,874,053	1.63 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, 2022 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, 2022, 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, 2022
FORECAST PRICES AND COSTS

	OIL		ALBERTA NGLs			NATURAL GAS				
Year	WTI Cushing @ Oklahoma ($US/bbl)	LIGHT, SWEET OIL @ Edmonton (40 °API, 0.3% S) ($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										
2023	86.00	110.67	38.13	54.47	114.67	4.33	4.18	0.0	0.0	0.750
2024	84.00	101.25	37.28	52.50	105.00	4.34	4.23	3.0	3.0	0.800
2025	80.00	96.18	37.68	50.00	100.00	4.00	3.89	2.0	2.0	0.800
2026	81.60	98.10	38.44	51.00	102.00	4.08	3.97	2.0	2.0	0.800
2027	83.23	100.06	39.21	52.02	104.04	4.16	4.05	2.0	2.0	0.800
2028	84.90	102.06	39.99	53.06	106.12	4.24	4.13	2.0	2.0	0.800
2029	86.59	104.10	40.79	54.12	108.24	4.33	4.22	2.0	2.0	0.800
2030	88.33	106.18	41.61	55.20	110.41	4.42	4.30	2.0	2.0	0.800
2031	90.09	108.31	42.44	56.31	112.62	4.50	4.39	2.0	2.0	0.800
2032	91.89	110.47	43.29	57.43	114.87	4.59	4.47	2.0	2.0	0.800
Thereafter	+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.
(3) Product sales prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2022, were $6.32 per Mcf for conventional natural gas, $111.56 per bbl for light and medium crude oil, $115.43 per bbl for condensate, $44.42 per bbl for NGL excluding condensate and $89.82 per bbl for NGL including condensate.

4. Reflects estimated well abandonment and reclamation costs ("**ARC**") as defined by NI 51-101 as all costs associated with the process of restoring Crew's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.

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 RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

	LIGHT CRUDE OIL & MEDIUM CRUDE OIL			NATURAL GAS LIQUIDS			CONVENTIONAL NATURAL GAS			OIL EQUIVALENT		
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 (Mmcf)**	**Gross Probable (Mmcf)**	**Gross Proved Plus Probable (Mmcf)**	**Gross Proved (Mboe)**	**Gross Probable (Mboe)**	**Gross Proved Plus Probable (Mboe)**
December 31, 2021	3,457	2,422	5,879	38,891	41,152	80,044	986,753	925,817	1,912,570	206,807	197,878	404,684
Extensions & Improved Recovery(1)	-	4,020	4,020	5,062	(4,390)	672	96,897	(17,577)	79,319	21,211	(3,300)	17,911
Infill Drilling	311	(130)	182	67	(11)	56	2,916	(470)	2,447	864	(219)	646
Technical Revisions(2)	(1,127)	(710)	(1,838)	(228)	(2,154)	(2,382)	(15,361)	13,638	(1,723)	(3,915)	(591)	(4,506)
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	(1,034)	(5,719)	(6,753)	(22,071)	(142,899)	(164,970)	(4,713)	(29,536)	(34,248)
Economic Factors	23	(72)	(49)	345	(238)	107	14,432	(4,716)	9,716	2,773	(1,096)	1,677
Production	(36)	-	(36)	(2,683)	-	(2,382)	(56,564)	-	(56,564)	12,146	-	(12,146)
December 31, 2022	2,628	5,530	8,158	40,420	28,641	69,061	1,007,002	773,792	1,780,795	210,882	163,136	374,018

Notes:

(1) Increases to Extensions & Improved Recovery are the result of step-out locations booked by Crew. Reserves additions for Extensions and Improved Recovery are combined and reported as "Extensions & Improved Recovery".

(2) Technical Revisions also include changes in reserves associated with changes in operating costs, capital costs and commodity price offsets.

(3) 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.

(4) Columns may not add due to rounding.

Corporate level technical revisions on a boe basis were -2% at the total proved level and -1% at the total proved plus probable level. Technical revisions were primarily due to operating cost increases, high-grading and removal of future development bookings in context of COGE Handbook recommended development timing windows, performance adjustments attributable to the Corporation's 2022 capital program, well performance and type curve changes, and reserves reclassifications. Other technical revisions were attributable to the Corporation's updated development planning resulting in adjustments to future development bookings, reflective of a continuing shift towards extended reach horizontal well designs and compliance with the COGE Handbook guidance on five year and ten year development plans.

Material changes in other categories were attributable to divestment of the Corporation's Attachie and Portage assets in the third quarter of 2022[3] (Dispositions), commodity pricing increases (Economic Factors), forecasted federal carbon tax increases to $170/tonne by 2030 (Economic Factors), royalty regime changes recently implemented in British Columbia (Economic Factors), and infill and extension location additions associated with Crew's 2022 development activity (Extensions and Infill Drilling).

[3] Crew's Attachie and Portage asset divestment yielded gross proceeds of $130 million and, based on the Corporation's year-end 2021 independent reserves evaluation, included associated Total Proved and Total Proved Plus Probable reserves of 4.7 mmboe and 34.2 mmboe, respectively, as well as future development capital of $25.7 million and $182.9 million, respectively.

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 nine 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
2020	-	3,222	211	1,980	7	606,328	-	27,202
2021	-	3,246	-	-	67,336	584,424	1,409	22,287
2022	311	2,463	-	-	79,157	571,575	3,486	23,833

Sproule has assigned 121,559 Mboe of proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with approximately $803 million of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Sproule Report accounts for approximately $372 million or 46% 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
2020	-	3,433	109	2,240	(2)	855,554	-	41,643
2021	-	2,365	-	-	23,878	837,326	(793)	37,552
2022	3,890	5,498	-	-	2,609	672,321	(2,758)	24,762

Sproule has assigned 142,314 Mboe of probable undeveloped reserves in the Sproule Report and has allocated additional future development capital of approximately $531 million to all probable undeveloped reserves, with none of the probable additional development capital forecast to be spent in the first two years.

As of December 31, 2022, undeveloped reserves represented 57.6% of total proved reserves and 70.6% of proved plus probable reserves. All of the proved plus probable undeveloped reserves are located in the Corporation's Montney assets in northeast British Columbia.

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. 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. 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 2023 and 2024 as well as in years beyond 2024) 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; (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 landowners, 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 and reservoir performance, geological conditions, production, prices, changes in company strategy, economic conditions and government restrictions. 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 a number of factors that are beyond the Corporation's control, including, without limitation, fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and changes thereto, well performance, and potential changes to B.C. government development permit approvals resulting from changes to Indigenous land and resource planning (see *"Risk Factors – Indigenous Land and Rights Claims"* and "*Industry Conditions - Indigenous Rights*").

Crew has no long term contracts that commit it to sell products at a price other than market prices. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves. For additional 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, 2022 for total proved plus probable reserves of $158.8 million, undiscounted ($117.5 million of which is scheduled beyond 20 years) or approximately $19.9 million, discounted at 10%, and for total proved reserves, $128.8 million, undiscounted ($81.6 million of which is scheduled beyond 20 years) or approximately $21.0 million, discounted at 10%. Where included in the Sproule Report, abandonment and reclamation costs were prepared in accordance with the COGE Handbook and as defined in NI 51-101, represent all costs associated with the process of restoring the Corporation's properties that 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 on a total proved plus probable basis, including abandonment and reclamation cost obligations for the entities that have been assigned reserves and material dedicated facilities (totaling $59.1 million, undiscounted), and for entities where no reserves have been assigned (totaling $38.9 million, undiscounted). The cost estimate in the Sproule Report also 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 (totaling $60.7 million, undiscounted).

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	59,121
Existing wells without developed reserves and associated facilities	38,946
Future wells with undeveloped reserves and associated facilities	60,729
Total abandonment and reclamation costs for developed and undeveloped reserves	158,796

Note:

(1) Costs referenced in the table above are based on forecast inflation rates as prepared by Sproule on December 31, 2022. See the "*Summary of Pricing and Inflation Rate Assumptions*" table on page 13 of this AIF.

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 $10.0 million ($7.3 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. Although Crew's asset retirement obligations decreased significantly following its Heavy Oil Disposition in 2021, the Corporation continues to progress abandonment and reclamation projects on its British Columbia assets.

Crew invested a record amount on abandonment and reclamation activities in 2022, totaling $13.1 million, reducing the Company's idle well count by 33%.

Future Development Costs

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

Year	Proved Reserves (MM$)	Proved Plus Probable Reserves (MM$)
2023	178	178
2024	201	201
2025	180	180
2026	111	111
2027	106	114
Thereafter	143	697
Total Undiscounted	**919**	**1,481**

Note:

(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 solely focused on the development of its Montney oil and liquids-rich natural gas assets in northeast British Columbia. The northeast British Columbia geographic area is made up of four areas: Septimus, West Septimus, (collectively referred to as "**Greater Septimus**"), Groundbirch, and Tower.

Board of Directors have approved 2023 capital expenditures ranging between $190 and $210 million, of which $35 to $45 million is planned to be directed to infrastructure and deposits on long lead items. A focus on achieving specific goals in the first half of 2023 is expected to result in Crew's 2023 drilling and completions being predominantly focused in H2 2023. The 2023 capital program includes the drilling of 15 (15.0 net) wells and completion of 12 (12.0 net) wells in the Greater Septimus and Tower areas. Crew's active development program is designed to continue targeting production growth, increasing adjusted funds flow and significantly improving leverage metrics, positioning the Corporation to develop its significant resource base prudently and strategically under its long term plan.

The following is a description of Crew's principal properties, plants, facilities and installations as at December 31, 2022. Production stated is production before deduction of royalties and includes royalty interests to Crew and, unless otherwise stated, reflects average production for 2022. Reserves 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, 2022 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, 2022.

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 slick water fracture stimulations. In 2022, Crew's production from this area averaged 16,855 boe/d weighted 78% to conventional natural gas (78,557 mcf/d), 11% condensate (1,908 bbls/d) and 11% to other NGLs (1,855 bbls/d). At December 31, 2022, the Corporation had 99 (96.6 net) producing liquids-rich natural gas wells and 1 (1.0 net) service well in the area. The Corporation's current production is processed through Crew's operated 120 Mmcf per day West Septimus facility, which at year end 2022, was owned 27.7% by the Corporation. In 2022, Crew drilled six (6.0 net) and completed five (5.0 net) liquids-rich Montney gas wells in the area.

Crew plans to drill five (5.0 net) and complete six (6.0 net) Ultra-Condensate Rich formation wells in this area in 2023.

During 2018, Crew constructed a pipeline system from the West Septimus facility through Groundbirch and into the Saturn meter station on the TC Energy 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 from the Groundbirch area.

As at December 31, 2022, the Sproule Report assigned proved plus probable reserves of 44,699 Mbbl of NGL and 862,263 Mmcf of conventional natural gas to Crew's interests in the West Septimus area. At year-end 2022, the Corporation owned 37,908 net acres of land with an average working interest of 91.3% in the area.

Septimus, British Columbia

The Septimus area is located approximately 13 kilometres southwest of Fort St. John, British Columbia. Crew's operations include liquids-rich natural gas from the Montney formation. At December 31, 2022, Crew had an interest in 66 (62.7 net) producing liquids-rich natural gas wells and 2 (1.3 net) service wells in the area. In 2022, production averaged 9,810 boe/d weighted 67% to conventional natural gas (39,668 mcf/d), 26% condensate (2,498 bbls/d) and 7% to other NGLs (701 bbls/d). The Corporation's current production is processed through Crew's operated 60 Mmcf per day Septimus facility, which at year-end 2022, was owned 27.7% by the Corporation. Crew will also be expanding the condensate handling capacity of the operated Septimus facility with the installation of a waste heat recovery unit in 2023. In 2022, Crew did not drill any wells in the Septimus area but did complete and bring on stream six (6.0 net) liquids-rich gas wells which were drilled in 2021.

Crew plans to drill ten (10.0 net) liquids-rich natural gas wells in this area during 2023. These wells are planned to be completed and brought on-stream in 2024.

As at December 31, 2022, the Sproule Report assigned total proved plus probable reserves of 6,453 Mbbl of light and medium crude oil, 12,865 Mbbl of NGL along with 367,382 Mmcf of conventional natural gas to Crew's interests in the Septimus area. At year-end 2022, the Corporation owned 14,393 net acres of land with an average working interest of 90.9% in this area.

Groundbirch, British Columbia

The Groundbirch area is located approximately 35 kilometres 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 formation. In 2022, the Corporation's production from this area averaged 4,718 boe/d weighted 93% to conventional natural gas (26,461 mcf/d), 3% to condensate (116 bbls/d) and 4% to other NGLs (193 bbls/d). At December 31, 2022, the Corporation had 12 (12.0 net) producing natural gas wells in the Groundbirch area. In 2022, Crew drilled and completed five (5.0 net) dry gas wells in the area. These wells were brought on stream in the third quarter of 2022.

Crew has no plans to drill in the Groundbirch area in 2023.

Production from Crew's Montney formation wells in the Groundbirch area is gathered into and processed at the Corporation's West Septimus facility.

As at December 31, 2022, the Sproule Report assigned total proved plus probable reserves of 10,876 Mbbl of NGL and 507,163 Mmcf of conventional natural gas to Crew's interests in the Groundbirch area. At year-end 2022, the Corporation owned 70,793 net acres of land with an average working interest of 95.4% in the area.

Tower, British Columbia

The Tower area is located approximately 13 kilometres south of Fort St. John, British Columbia and includes lands adjacent to and northeast of Septimus. Crew's operations include oil and liquids-rich solution gas from the Montney formation. In 2022, Crew's production from the area averaged 514 boe/d weighted 17% to light and medium crude oil (85 bbls/d), 73% to conventional natural gas (2,262 mcf/d) and 10% to NGL (52 bbls/d). At December 31, 2022, the Corporation had 9 (7.7 net) producing oil wells in the area. Crew drilled six (6.0 net) oil wells in the Tower area in the fourth quarter of 2022. These wells are expected to be completed and brought on production in the third quarter of 2023. Crew's gas production in the Tower area is processed through the Septimus gas facility and the oil production is trucked to market from a 100% Crew owned and operated oil processing facility.

As at December 31, 2022, the Sproule Report assigned total proved plus probable reserves of 1,687 Mbbl of light and medium crude oil, 558 Mbbl of NGL and 24,273 Mmcf of conventional natural gas to Crew's interests in the Tower area. At year-end 2022, the Corporation owned 32,590 net acres of land with an average working interest of 83.3% 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 1,379 boe/d of production in 2022. As at December 31, 2022, the Corporation owned 2 (0.5 net) producing oil wells and 20 (10.8 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, 2022.

Location	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
British Columbia	12	10.0	11	8.7	227	206.7	107	66.9
Total	**12**	**10.0**	**11**	**8.7**	**227**	**206.7**	**107**	**66.9**

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, 2022.

	Developed Acres		**Undeveloped Acres(1)**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	0	0	322	209	322	209
British Columbia	155,988	87,724	294,533	224,282	450,520	312,006
Saskatchewan	0	0	81	81	81	81
Other Canada	0	0	376,920	43,896	376,920	43,896
Total	**155,988**	**87,724**	**671,856**	**268,468**	**827,843**	**356,192**

Notes:

(1) Undeveloped Acres includes our interest in 656,889 gross acres (255,926 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.
(2) Columns may not add due to rounding.

Of the Corporation's undeveloped land, there are no undeveloped acres scheduled to expire by December 31, 2023.

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, 2022, Crew does not have any material commitments to buy or sell natural gas or crude oil production.

As at December 31, 2022, the Corporation held derivative commodity contracts as follows:

Notional Quantity	**Term**	**Strike Price**	**Option Traded**	**Fair Value**
Natural Gas – AECO Daily Index:				
45,000 gj/day	January 1, 2023 - March 31, 2023	$5.26/gj	Swap	$ 2,094
12,500 gj/day	January 1, 2023 - December 31, 2023	$4.77/gj	Swap	5,034
35,000 gj/day	April 1, 2023 - June 30, 2023	$4.08/gj	Swap	2,663
7,500 gj/day	April 1, 2023 - October 31, 2023	$4.31/gj	Swap	1,950
35,000 gj/day	July 1, 2023 - September 30, 2023	$3.83/gj	Swap	2,862
35,000 gj/day	October 1, 2023 - December 31, 2023	$4.40/gj	Swap	2,373
Natural Gas – AECO Monthly Index:				
7,500 gj/day	January 1, 2023 - March 31, 2023	$5.95/gj	Swap	723
10,000 gj/day	January 1, 2023 - December 31, 2023	$4.00 - $5.18/gj	Collar(1)	2,469
7,500 gj/day	April 1, 2023 - June 30, 2023	$4.41/gj	Swap	723
7,500 gj/day	July 1, 2023 - September 30, 2023	$4.02/gj	Swap	723
7,500 gj/day	October 1, 2023 - December 31, 2023	$4.72/gj	Swap	723
CDN$ Edmonton C5 Blended Index:				
1,250 bbl/day	January 1, 2023 - June 30, 2023	$106.80/bbl	Swap	(354)
250 bbl/day	January 1, 2023 - December 31, 2023	$102.50/bbl	Swap	(82)
Total				**$ 21,901**

Note:

(1) The referenced contract is a costless collar whereby the Corporation receives $4.00/gj when the market price is below $4.00/gj, and receives $5.18/gj when the market price is above $5.18/gj.

Subsequent to December 31, 2022, the Corporation entered into the following derivative commodity contracts:

Notional Quantity	**Term**	**Strike Price**	**Option Traded**
Natural Gas – USD$ AECO Basis:			
2,500 mmbtu/day	April 1, 2023 - October 31, 2023	$(1.25)/mmbtu	Swap
CDN$ Edmonton C5 Blended Index:			
750 bbl/day	July 1, 2023 - December 31, 2023	$99.50/bbl	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 contracted transportation and processing capacity as compared to Crew's proved reserves production forecast is $6 million in the first five years of the forecast and an additional $3 million in years six through ten of the forecast. Contracted transportation capacity in excess of the proved reserves production forecast in the first five years is 6 Mmcf/d of conventional natural gas, with an additional 5 Mmcf/d of excess natural gas transportation capacity in years six through ten of the forecast. Contracted processing capacity in excess of the proved reserves production forecast only occurs in the first five years of the forecast and is 3 Mmcf/d of conventional 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, 2022, 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, 2022. 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 2023 and does not anticipate being in a cash income tax payable position through 2024 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, 2022:

	($ thousands)
Property acquisition costs	
Proved properties	-
Unproved properties	621
Exploration costs	1,470
Development costs	175,743
Corporate acquisitions	-
Property dispositions	(131,001)
Total	**46,834**

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, 2022.

	Gross			Net		
	Exploration	Development	Total	Exploration	Development	Total
Crude Oil	-	-	-	-	-	-
Natural Gas	-	17	17	-	17	17
Dry[(1)]	-	-	-	-	-	-
Service[(2)]	-	-	-	-	-	-
Stratigraphic Test	-	-	-	-	-	-
Total	**-**	**17**	**17**	**-**	**17**	**17**

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) "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 planned exploration and development activities in 2023, 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, 2023 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		Natural Gas Liquids		Conventional Natural Gas		Total Oil Equivalent	
Reserves Category	**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	**574**	**543**	**7,302**	**6,192**	**157,562**	**129,696**	**34,136**	**28,351**
Septimus	31	27	1,865	1,561	36,392	27,512	7,961	6,173
West Septimus	-	-	5,007	4,244	72,918	59,797	17,160	14,210
Groundbirch	-	-	321	292	36,482	32,723	6,401	5,746
Total Proved Plus Probable	**879**	**833**	**8,005**	**6,740**	**168,400**	**138,696**	**36,951**	**30,689**
Septimus	31	27	2,000	1,672	38,534	29,074	8,454	6,545
West Septimus	-	-	5,507	4,618	77,518	63,597	18,426	15,218
Groundbirch	-	-	332	301	37,736	33,732	6,621	5,923

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 2023 production as reflected in the Sproule Report. The Corporation's Groundbirch area accounts for approximately 18% of estimated 2023 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			
	2022			
	Dec. 31	**Sept. 30**	**Jun. 30**	**Mar. 31**
Average Daily Production[1]				
Light Crude Oil and Medium Crude Oil (bbl/d)	84	83	108	116
Conventional Natural Gas (Mcf/d)	157,732	145,715	157,547	159,007
NGLs (bbl/d)	6,520	7,423	8,678	6,782
Condensate (bbl/d)	3,955	4,731	5,570	3,926
Other NGLs (bbl/d)	2,565	2,692	3,108	2,856
Combined (BOE/d)	32,893	31,792	35,044	33,399
Average Price Received[2]				
Light Crude Oil and Medium Crude Oil ($/bbl)	100.10	104.30	130.66	107.35
Conventional Natural Gas ($/Mcf)	6.14	5.65	8.17	5.29
NGLs ($/bbl)	65.17	82.63	101.07	87.81
Condensate ($/bbl)	105.30	106.15	130.07	116.27
Other NGLs ($/bbl)	37.42	41.30	49.09	48.72
Combined ($/BOE)	45.25	45.46	62.16	43.39
Transportation Expenses				
Light Crude Oil and Medium Crude Oil ($/bbl)	2.57	5.23	5.06	2.49
Conventional Natural Gas ($/Mcf)	0.64	0.67	0.66	0.66
NGLs ($/bbl)	(0.07)	3.54	3.31	2.21
Condensate ($/bbl)	(0.17)	1.91	1.81	0.04
Other NGLs ($/bbl)	6.03	6.40	6.00	5.19
Transportation Revenue ($/boe)	(0.49)	(0.51)	(0.46)	(0.48)
Combined ($/BOE)	3.05	3.42	3.33	3.12
Royalties Paid				
Light Crude Oil and Medium Crude Oil ($/bbl)	4.50	5.75	13.77	8.53
Conventional Natural Gas ($/Mcf)	0.83	0.91	0.61	0.95
NGLs ($/bbl)	9.43	11.36	4.60	5.38
Condensate ($/bbl)	15.45	14.46	5.31	7.38
Other NGLs ($/bbl)	2.99	5.91	3.30	2.63
Combined ($/BOE)	6.09	6.86	3.98	2.78
Operating Expenses				
Light Crude Oil and Medium Crude Oil ($/bbl)	68.71	75.41	59.96	47.25
Conventional Natural Gas ($/Mcf)	0.59	0.68	0.64	0.06
NGLs ($/bbl)	2.98	4.14	3.77	3.45
Condensate ($/bbl)	3.43	4.20	3.79	3.48
Other NGLs ($/bbl)	3.28	4.03	3.73	3.42
Processing revenue ($/BOE)	(0.04)	(0.04)	(0.10)	(0.06)
Combined ($/BOE)	3.47	4.12	3.52	3.50
Netback Received[3][4]				
Light Crude Oil and Medium Crude Oil ($/bbl)	24.32	17.91	51.87	49.08
Conventional Natural Gas ($/Mcf)	4.22	3.53	6.45	3.83
NGLs ($/bbl)	62.40	63.60	89.39	76.77
Condensate ($/bbl)	86.59	85.58	119.16	105.37
Other NGLs ($/bbl)	25.12	24.96	36.06	37.48
Combined ($/BOE)	32.64	31.06	51.33	33.99

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 and Other Financial Measures*" contained within Crew's MD&A for the year ended December 31, 2022, on page 25, available on SEDAR at www.sedar.com, for additional disclosures relating to this non-Gaap measure, which information is incorporated in this Annual Information Form by reference.

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, 2022:

	Light Crude Oil & Medium Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	Condensate (bbl/d)	NGLS (bbl/d)	Oil Equivalent (BOE/d)
Septimus	-	39,668	2,498	701	9,810
West Septimus	-	78,557	1,907	1,855	16,855
Groundbirch	-	26,461	116	192	4,718
Other(1)	98	10,285	25	56	1,893
Total	**98**	**154,971**	**4,546**	**2,804**	**33,276**

Note:

(1) Includes Tower and Other.

For the year ended December 31, 2022, approximately 8% of Crew's gross production revenue was derived from crude oil and natural gas liquids production (other than condensate), 32% was derived from condensate production, and 60% was derived from conventional natural gas production.

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 and 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, and the Corporation is not permitted to make distributions in any fiscal year that exceed $20 million in aggregate.

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 following 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: 2022 – 101.040%; and 2023 and thereafter – 100.000%.

On September 19, 2022 the Corporation redeemed and extinguished $128 million principal amount of 2024 Notes at a redemption price of $1,010.40 for each $1,000 of principal amount redeemed, plus accrued and unpaid interest. The Corporation currently has $172 million principal amount of 2024 Notes which remain outstanding.

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.

Credit Facility

The Corporation has a credit facility with a syndicate of lenders which, as at the date hereof, provides for a $170 million extendible revolving line of credit and a $30 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 2, 2023. 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 positive trend and B by Standard & Poors Rating Services ("**S&P**") with a stable outlook. 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 positive trend and B+ by S&P with a stable outlook. 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.

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. 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. 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**
2022			
January	$ 3.80	$ 2.87	29,128,731
February	$ 3.91	$ 3.14	21,283,669
March	$ 5.29	$ 3.22	33,079,140
April	$ 5.68	$ 4.50	22,920,834
May	$ 6.80	$ 4.62	32,007,904
June	$ 6.75	$ 4.31	22,092,607
July	$ 5.65	$ 3.80	15,520,580
August	$ 6.99	$ 4.91	18,588,636
September	$ 6.39	$ 4.73	12,331,815
October	$ 6.09	$ 5.33	11,727,738
November	$ 6.94	$ 5.83	15,464,221
December	$ 6.92	$ 5.38	21,587,827
2023			
January	$ 5.58	$ 4.49	17,387,873
February	$ 4.75	$ 4.15	11,096,255
March (1-7)	$ 5.11	$ 4.60	2,461,544

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
March 10, 2022	Incentive Awards	152,000	N/A
April 1, 2022	Incentive Awards	3,024,500	N/A
April 8, 2022	Incentive Awards	30,000	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)(4) Alberta, Canada Age: 66	Chairman	September, 2003	Partner and Chairman, Burnet, Duckworth & Palmer LLP (a Calgary law firm).
Gail Hannon(1)(3)(4) Alberta, Canada Age: 59	Director	May, 2021	Vice President, Corporate & Financial Planning of Artis Exploration Ltd., a private oil and gas company, since 2019; prior thereto, was Chief Financial Officer of Granite Oil Corp. from 2015 to 2019; and prior thereto, Chief Financial Officer of DeeThree Exploration Ltd. (a public oil and gas company) from 2009 to 2015.
John M. Hooks(1)(3) Alberta, Canada Age: 65	Director	April, 2022	Chairman and Chief Executive Officer (and formerly President) of PHX Energy Services Corp. (a public oil and gas services company) and its predecessors since 1995.
Karen Nielsen, ICD.D(2)(3) Alberta, Canada Age: 55	Lead Independent Director	May, 2018	Managing Director, Global Renewables of ATCO Group since early 2022; prior thereto, was Chief Development Officer of Seven Generations Energy since June, 2019; prior thereto was Senior Vice President and General Manager, Generation at ATCO Electricity Generation from 2017 to 2019; prior thereto, was Vice President, Operations at ARC Resources Ltd. from 2013 to 2017.

Name, Age, Province and Country of Residence	Office Held	Date First Elected or Appointed as a Director	Principal Occupation
Ryan Shay, CPA, CA, CFA (1)(2)(4) Alberta, Canada Age: 51	Director	May, 2018	Vice President, Finance and Chief Financial Officer of Perpetual Energy Inc. since May 2021 and Rubellite Energy Inc. since July 2022; prior thereto, was an independent business person since 2016; prior thereto, was Managing Director, Head of Investment Banking at Cormark Securities Inc. until 2016.
Dale O. Shwed Alberta, Canada Age: 64	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 Energy Ltd.
John G. Leach, CPA, CA Alberta, Canada Age: 58	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 Energy Ltd.
James Taylor Alberta, Canada Age: 48	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: 58	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: 57	Vice-President, Government & 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: 50	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: 55	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: 47	Vice-President, Land & 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.
Craig Turchak, CPA, CGA Alberta, Canada Age: 42	Vice-President, Finance & Controller	N/A	Vice-President, Finance & Controller of the Corporation since January, 2022; prior thereto, Controller of the Corporation since 2013; prior thereto, Manager of Operations Accounting of the Corporation since 2010; prior thereto, held various financial and accounting roles of increasing responsibility with the Corporation since 2004.
Michael D. Sandrelli Alberta, Canada Age: 54	Corporate Secretary	N/A	Senior 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 and EHS&S 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, 2022, the directors and executive officers of Crew, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 17.7 million Common Shares representing approximately 11.3% 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.

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.

John 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 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
Ryan Shay	Yes	Yes	Mr. Shay has in excess of 25 years of experience in the oil and gas industry and is currently the Vice President, Finance and Chief Financial Officer of Perpetual Energy and Rubellite Energy Inc, both growth-oriented, Alberta based exploration and production companies. Previously, Mr. Shay was Managing Director, Head of Investment Banking at Cormark Securities Inc. until 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 of Perpetual Energy Inc., Rubellite Energy Inc., and was formerly a Director of Journey Energy Inc., all publicly listed TSX issuers.

Name	Independent	Financially Literate	Relevant Education and Experience
Gail Hannon	Yes	Yes	Ms. Hannon has over 30 years of diverse accounting and reporting experience having worked in various management and executive roles in the energy industry. Ms. Hannon is currently the Vice President, Corporate & Financial Planning with Artis Exploration Ltd., a private oil and gas exploration, development and production company, a position she has held since 2019. Formerly, Ms. Hannon served as the Chief Financial Officer of DeeThree Exploration Ltd. (a public oil and gas company) from 2009 to 2015 when DeeThree reorganized into two separate energy companies, one of which was Granite Oil Corp., where she continued as Chief Financial Officer until early 2019. Ms. Hannon obtained her Chartered Management Accountant designation in 1996 (now the Chartered Professional Accountant designation). Ms. Hannon is a member of the Institute of Corporate Directors.
John Hooks	Yes	Yes	Mr. Hooks is the Chief Executive Officer and Chairman of the Board of Directors of PHX Energy Services Corp., a TSX listed company, and is on the Board of Directors of several other publicly and privately owned companies that are focussed on renewal energy and energy services. Mr. Hooks has over 30 years of operations and senior executive leadership experience in the energy industry in both the public and private sectors. Mr. Hooks also sits on the Board of Directors and is a member of the Compensation and Corporate Governance Committees of CES Energy Solutions Corp., a publicly listed TSX issuer, and is a former member of the Board of Directors of Savanna Energy Services Corp.

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 2022 and 2021:

	Aggregate fees billed ($)	
	2022	**2021**
Audit fees	333,840	300,670
Audit-related fees	-	-
Tax fees	32,207	24,343
All other fees	3,001	-
	369,048	325,013

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 54 full-time employees, of which 48 are located in the head office including two contractors, and six are located in the field. Crew intends to add additional professional and administrative staff as the need arises.

INDUSTRY CONDITIONS

Companies operating in the Canadian oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government; and with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Western Canadian oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted.

The Corporation holds interests in crude oil, NGL and natural gas properties, along with related assets, primarily in the Canadian province of British Columbia. The Corporation's assets and operations are regulated by administrative agencies that derive their authority from 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 and construction of related infrastructure; (ii) technical drilling and well requirements; (iii) permitted locations and access to operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct 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 some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the province of British Columbia where the Corporation's assets are primarily located. While these matters 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 matters carefully.

Pricing and Marketing in Canada

Crude Oil

Oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("**OPEC**") forecasts robust growth in world oil demand in 2023, spurred by the relaxation of China's zero-COVID policy. OPEC predicts global oil demand to rise by 2.25 million barrels per day in 2023, despite newly emerging COVID-19 variants, interest rate increases in major economies and other uncertainties with respect to the world economy.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of oil and gas from the region. In addition, certain countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near term effects on Russia. The long-term impacts of the conflict remain uncertain.

Natural Gas

Negotiations between buyers and sellers determines 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 of sale. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids ("NGLs")

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms of sale.

Exports from Canada

The Canada Energy Regulatory (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and long-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "**CERA**"). 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.

Transportation Constraints and Marketing

Capacity to transport production from Western Canada to Eastern Canada, the United States and other international markets has been, and continues to be, a major constraint on the exportation of crude oil, natural gas and NGLs. Although certain pipeline and other transportation projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and socio-political factors. Due in part to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have on occasion experienced low commodity pricing relative to other markets in the last several years.

Oil Pipelines

Under Canadian constitutional law, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and 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 also require approvals from several levels of government in the United States.

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. 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 and the price received.

Specific Pipeline Updates

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2022. The pipeline is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's initial December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge Inc. stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. In August 2022, the United States District Court for Western Michigan rejected the Attorney General of Michigan's efforts to move the dispute to Michigan State Court, citing important federal interests at stake in having the dispute heard in federal court. Michigan's Attorney General intends to appeal the decision.

In September 2022, the District Court of Wisconsin ruled in favour of the Bad River Band in its dispute with Enbridge Inc. over the Enbridge Line 5 pipeline system in that state. Stopping short of ordering the system to be shut down, the Court ruled that the Bad River Band is entitled to financial compensation, and ordered Enbridge Inc. to reroute the pipeline around Bad River territory within five years.

Natural Gas and Liquefied Natural Gas ("LNG")

Natural gas prices in western Canada have been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to infrastructure 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 is generally lower than the prices received in other North American regions. The Corporation has entered into firm service commitments in order to mitigate its exposure to volatile AECO pricing. Firm service agreements provide the Corporation with geographical diversification across North America, including Alberta, British Columbia, Eastern Canada and United States (Midwest) markets.

Required repairs or upgrades to existing pipeline systems in western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation received federal approval to expand the Nova Gas Transmission Line system (the "**NGTL System**") and the expanded NGTL System was completed in April 2022.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition 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 LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Phase 1 of the LNG Canada the LNG Canada project reached 70% completion in October 2022, with a completion target of 2025.

In May 2020, TC Energy Corporation sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its regulatory approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of November 2022, construction of the CGL Pipeline was approximately 80% complete.

Woodfibre LNG Limited issued a notice to proceed with construction of the Woodfibre LNG project to its prime contractor in April 2022. The Woodfibre LNG project is located near Squamish, British Columbia, and upon completion will produce approximately 2.1 million tonnes of LNG per year. Major construction is set to commence in 2023, with substantial completion of the project expected in late 2027. In November 2022, Enbridge Inc. completed a transaction with Pacific Energy Corporation Limited, the owner of Woodfibre LNG Limited, to retain a 30% ownership stake in the project.

In addition to LNG Canada, the CGL Pipeline and the Woodfibre LNG project, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

Marine Tankers

The Oil Tanker Moratorium Act (Canada), which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement ("**CETA**"), the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could impact Western Canada's oil and gas industry as a whole, including the Corporation's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia and Europe.

Canada is also party to the CETA, which provides for duty-free, quota-free European Union market access for Canadian crude oil and natural gas products. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the Canada-United Kingdom Trade Continuity Agreement ("**CUKTCA**"), which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

While it is uncertain what effect CETA, CUKTCA or any other trade agreements will have on the petroleum 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

Mineral rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (collectively, "**leases**") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

All of the provinces of Western Canada have all 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 disposition. 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 oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned 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 companies seeking to explore for and/or develop oil and natural gas reserves.

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**") manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations through *An Act to Amend the Indian Oil and Gas Act*, and the accompanying regulations. The Corporation does not have operations on Indigenous reserve lands.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

Producers and working interest owners of oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

Occasionally, both the federal government and the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

In addition, from time-to-time, including during the COVID-19 pandemic, the federal government creates incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry as well as other industries in Canada.

British Columbia

Crown royalties

On October 7, 2021, the Government of British Columbia launched a comprehensive review of its oil and gas royalty system. The new oil and gas royalty system (the "**New Framework**") was announced in May 2022. The New Framework will increase the minimum royalty rate from 3% to 5%, and eliminate the Deep Well, Marginal Well, Ultra-marginal Well, Low Productivity Well Rate Reduction and Clean Growth Infrastructure royalty programs (the "**Old Royalty Programs**"). New wells drilled under the New Framework will pay the flat royalty of 5% until capital spent on drilling and completions is recovered, at which point they will move to a price-sensitive royalty rate between 5% and 40%, depending on the specific commodity being produced.

Wells drilled on or after September 1, 2022 will not be eligible to qualify for the Old Royalty Programs, and will pay a 5% royalty rate for the equivalent of the first 12 months of production. Following this period, these wells will pay the prevailing price-sensitive royalty rates until September 1, 2024 when all wells will be transitioned to the New Framework. Wells drilled prior to September 1, 2022 will pay royalties based on the current framework until September 1, 2024, at which time those wells will be transitioned to the New Framework and will no longer be able to take advantage of the Old Royalty Programs.

Under the current system, Crown royalties payable on the production of oil and natural gas in British Columbia vary by market price, well type and the characteristics of the substances being produced. Producers of oil and natural gas receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner. In addition to these negotiated royalties, producers of oil and natural gas from freehold lands in British Columbia also pay monthly freehold production taxes to the Government of British Columbia.

For 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. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax to the Government of British Columbia.

Regulatory Authorities and Environmental Regulation

General

The Western Canadian oil and 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 oil and 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, future changes to environmental legislation, including legislation related to air pollution and greenhouse gas ("**GHG**") emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("**CO2e**")), may impose further requirements on operators and other companies in the oil and gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

The CERA and *Impact Assessment Act* (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency (the "**IA Agency**") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75 kilometres of new rights of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

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.

In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") regulates conventional oil and natural gas producers, shale gas producers and other operators of oil and natural gas facilities in the province. Under the OGAA, the British Columbia Energy Regulator ("**BCER**") has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BCER to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

In November 2022, the Government of British Columbia passed the Energy Statutes Amendment Act, 2022 (the "**ESA Act**"). The ESA Act changed the name of the British Columbia Oil and Gas Commission ("**BCOGC**") to the British Columbia Energy Regulator, and its mandate expanded to include oversight of hydrogen, ammonia and methanol. In support of the government's stated desire to transition away from fossil fuels and grow the province's hydrogen industry, the OGAA will also be renamed the Energy Resources Activities Act (the "**ERAA**"). In addition to expanding the British Columbia Energy Regulator's jurisdiction to include hydrogen, ammonia and methanol, the updated ERAA also expanded director and officer responsibility for costs associated with orphan sites.

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The *Drilling and Production Regulation* requires a 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 BCER before resuming production. The permitting process requires 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 BCOGC (as the BCER was then known) 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 "**KSMMA Area**"). The BCOGC introduced enhancements to the Special Project Order in April 2021. Boundaries within KSMMA were reduced, while technical requirements were increased. Permit holders in the KSMMA Area are subject to additional requirements before and after conducting hydraulic fracturing operations, including: (1) developing a seismic monitoring and mitigation plan that is submitted to the BCOGC, (2) notifying the BCOGC and local residents about planned hydraulic fracturing operations and (3) submitting to the BCOGC a report respecting monitoring of hydraulic fracturing operations after the conclusion of 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 BCOGC 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 BCOGC. Under the enhanced Special Project Order, a magnitude 3.0 or above seismic event will result in the immediate suspension of fracturing activities from the suspected well(s) for a minimum of five calendar days. Future earthquakes outside of the KSMMA Area may trigger the introduction of similar requirements elsewhere in the province.

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. These requirements are outlined in provincial legislation, namely the Water Sustainability Act and the Dam Safety Regulation. Despite these regulatory requirements, a number of unlicensed dams have been identified throughout northeastern British Columbia that have been constructed without the requisite regulatory authorizations. The BCER has issued compliance orders with respect to individual dams, but it remains 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 regulatory authorities decide to address these unauthorized projects, particularly where the Corporation is not strictly complying with the current regulatory framework.

An updated *Environmental Assessment Act* came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia 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 British Columbia Environmental Assessment Office will consider the environmental, health, cultural, social and economic effects of a proposed project.

Liability Management

British Columbia

The BCER has moved away from the formulaic approach to liability management set out in the Liability Management Rating Program, towards a more holistic assessment of a permit holder's ability to meet its abandonment and reclamation obligations. The BCOGC (as the BCER was then known) implemented the Permittee Capability Assessment on April 1, 2022 (the "**BC PCA**"). Under the BC PCA, the financial risk of a permit holder is assessed based on its: (i) assets to liabilities ratio; (ii) net profit margin (three-year average); (iii) interest coverage ratio; (iv) cash flow to debt ratio; and (v) debt to equity ratio. A permit holder is assessed on these factors based on the financial information it is required to submit to the BCER intermittently throughout the year. The permit holder is then evaluated on the magnitude of its liabilities, based on the deemed abandonment, assessment, remediation and reclamation liability associated with the permit holder's dormant, inactive, and marginal sites. If the BCER deems a permit holder to be high-risk under the BC PCA based on its financial risk and the magnitude of its liabilities, the regulator may require that permit holder to engage in corrective action. Corrective action could include the submission of security deposits and/or the completion of liability reduction work. Regarding the latter, the BCER will attempt to engage with permit holders to develop corrective action plans prior to issuing corrective action requirements.

In the spring of 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 levy. The OGAA permits the BCER to impose more than one levy in a given calendar year.

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 BCER, 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 the corresponding annual work plan.

The Government of British Columbia passed amendments to the Oil and Gas Activities Act under the Miscellaneous Statutes Amendment Act (No.2) in October 2021. These amendments allow the BCER to grant exemptions for strict compliance with the requirements of the Dormancy Regulation. In turn, this may mean that a permit holder can, with approval, depart from the regulated timelines set under the Dormancy Regulation. The relevant amendments which provide the BCER with the power to grant these exemptions came into force on October 28, 2021.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. 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 changes 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. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

In line with the Prime Minister's pledge to impose a cap on emissions from the oil and gas sector, the federal government published a discussion paper on July 18, 2022 that outlines two potential regulatory options for such a cap. Those proposed options are either to: (i) implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. These options are currently under review and interested parties had the opportunity to make submissions regarding the proposed cap, ending in September 2022. The form of emissions cap on the oil and gas sector and the overall effect of such a cap remain uncertain.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. 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 output-based pricing system ("**OBPS**") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50/tonne of CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $65/tonne of CO2e.

While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

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 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 the intentional venting of methane and ensure that 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. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The Canadian Net-Zero Emissions Accountability Act (the "**CNEAA**") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions-reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and Crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada introduced its 2030 Emissions Reduction Plan (the "**2030 ERP**") on March 29, 2022. In the 2030 ERP, the Government of Canada proposes a roadmap for Canada's reduction of GHG emissions to 40-45% below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the oil and gas sector, among other measures.

On June 8, 2022 the Canadian Greenhouse Gas Offset Credit System Regulations were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the OBPS or those seeking to meet voluntary targets.

On June 20, 2022, the Clean Fuel Regulations came into force, establishing Canada's Clean Fuel Standard. The Clean Fuel Standard will replace the former Renewable Fuels Regulation, and aims to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives. Coming into force in 2023, the Clean Fuel Standard will impose obligations on primary suppliers of transportation fuels in Canada and require fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emission fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. Beginning in 2022, the federal government plans to spend $319 million over seven years to ramp up CCUS in Canada, as this is expected to be a critical element of the plan to reach net-zero by 2050.

British Columbia

In August 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 fuel charge. The fuel charge is currently set at $65/tonne of CO2e and will continue to increase in line with the GGPPA minimum charge. Federal carbon pricing mechanisms are not currently in force in British Columbia, as the province's programs currently meet or exceed the federal benchmark stringency requirements.

In January 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.

In December 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 natural gas production; (v) reducing 45% of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles. Complementing its CleanBC plan, on March 26, 2021, the Government of British Columbia announced a number of sector-specific emissions reduction targets, established with reference to 2007 emissions levels, that it aims to achieve by 2030, including reduction targets of 27-32% for the transportation sector, 38-43% for industry and 33-38% for oil and gas.

The Government of British Columbia established the CleanBC Industry Fund in 2019 to support clean industry development in the province. The fund uses a portion of carbon tax revenue paid by large emitters to invest in projects aimed at reducing greenhouse gas emissions. In March 2021, the Government of British Columbia temporarily increased the provincial share of funding to up to 90% of project costs with a cap of $25 million per project. In 2021, the CleanBC Industry Fund invested $83.5 million in 32 emissions performance projects across British Columbia.

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "**CleanBC Roadmap**"), aimed at helping British Columbia achieve its 2030 emission reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90% of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries, and for increased support for clean hydrogen and negative emissions technology. Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

In January 2020, the BCOGC (as the BCER was then known) implemented 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. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the Declaration on the Rights of Indigenous Peoples Act ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "**Progress Report**"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and the UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in Yahey v British Columbia (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nations ("**BRFN**") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. The Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia and may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties, as seen in Alberta.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "**BRFN Agreement**"). The BRFN Agreement aims to address the cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200-million restoration fund by June 2025, an ecosystem-based management approach for future land-use planning in culturally important areas, limits on new petroleum and natural gas development, and a new planning regime for future oil and gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on petroleum and natural gas revenue sharing and provincial royalty revenue sharing in the next two fiscal years.

The BRFN Agreement has acted as a blueprint for other agreements between the Government of British Columbia and Indigenous groups in Treaty 8 territory. On January 20, 2023, the Government of British Columbia and four Treaty 8 First Nations – Fort Nelson First Nations, Saulteau First Nations, Halfway River First Nation and Doig River First Nations – announced a consensus on a collaborative approach to land and resource planning (the "**Consensus Agreement**"). The Consensus Agreement implements various initiatives including a "cumulative effects" management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue-sharing approach to support the priorities of Treaty 8 First Nations communities.

The long-term impacts of the Blueberry Decision on the Canadian oil and gas industry remain uncertain. See "Risk Factors – *Indigenous Lands and Rights Claims*".

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, or 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 equity or debt, 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 or 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, or 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 or 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.

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 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 of the Corporation's reserves 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, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Oil and natural gas prices may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the continuing impacts of the COVID-19 pandemic, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, the Russia Ukrainian war and conflicts in the Middle East. Prices for oil 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 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*".

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.

Adverse Economic Conditions

Adverse general economic, business, and industry conditions could have a material adverse effect on the Corporation's results of operations and cash flow

The demand for energy, including crude oil, NGL and natural gas, is generally linked to broad-based economic activities. If there was a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political development in the United States, Europe, or Asia, there could be a significant adverse effect on global financial markets and commodity prices. In addition, hostilities in the Middle East, Ukraine, and Taiwan and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Global or national health concerns, including the outbreak of pandemic or contagious diseases may adversely affect the Corporation by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGL and natural gas, (ii) impairing its supply chain, for example, by limiting the manufacturing of materials or the supply of goods and services used in the Corporation's operations, and (iii) affecting the health of its workforce, rendering employees unable to work or travel. These and other factors disclosed elsewhere in this Annual Information Form that affect the supply and demand for crude oil, NGL and natural gas, and Crew's business and industry, could ultimately have an adverse impact on the Corporation's financial condition, financial performance, and cash flows.

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, 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 certain jurisdictions, institutions including government-sponsored entities, have decreased 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 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 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

The Corporation's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact the Corporation's existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits for the Corporation's activities or restrict the operation of third-party infrastructure that the Corporation relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact the Corporation's results.

Other government and political factors that could adversely affect the Corporation's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Corporation's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for the Corporation's products.

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. 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 – Regulatory Authorities and Environmental Regulation" and "Industry Conditions – Transportation Constraints and Marketing".

Russian Ukrainian War

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Many countries throughout the world have provided aid to the Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the Russian invasion. The North Atlantic Treaty Organization ("**NATO**") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy.

In addition, certain countries including Canada have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. In addition, in September 2022 the 1,200 kilometre twin Nord Stream natural gas pipelines that were built to carry natural gas from Russia to Germany exploded underwater, likely as a result of sabotage. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply of energy and high prices of oil and natural gas could have a significant adverse impact on the world economy.

COVID-19 and its Effect on the Global Economy

The COVID-19 pandemic continues to cause disruptions in economic activity in Canada and internationally and impact demand for oil, NGL and natural gas.

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, liquids and natural gas. Since 2020, oil prices have largely recovered from their historic lows, and most countries have resumed full economic activity without any restrictions. However, certain countries, such as China, continue to experience varying degrees of virus outbreak. Any reduction in economic activity in certain countries resulting from COVID-19 outbreaks, government-imposed lockdowns and other restrictions, may have a negative effect on demand for oil, NGL and natural gas.

Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on the Corporation's operational results and financial condition. Low prices for oil, NGL and natural gas will reduce the Corporation's funds from operations and impact the Corporation's level of capital investment, and may result in the reduction of production at certain producing properties.

The extent to which the Corporation's operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond its control such as the duration and scope of the pandemic, additional actions taken by business and government in response to the pandemic and the speed and effectiveness of responses to combat the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified herein, the extent of which is not yet known.

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 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 – Regulatory Authorities and Environmental Regulation - Liability Management*" 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, extreme cold and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- availability and productivity of skilled labour;
- political uncertainty;
- environmental and Indigenous activism that potentially results in delays or cancellations of projects; 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, Trucking 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 truck and 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, trucking and railway lines. Unexpected shutdowns 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.

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 for, and 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 regulations or implementation of additional regulations may reduce the demand for oil, NGL and natural gas, increase the Corporation's costs, and 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 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".*

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".*

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. For example, in May 2022 the Government of British Columbia announced comprehensive changes to its oil and gas royalty system by increasing the minimum royalty rate from three per cent to five percent and eliminating many legacy royalty programs, replacing them with a new program in which new wells drilled will pay the flat royalty of five per cent until capital spent on drilling and completions is recovered, at which point they will move to a price sensitive royalty rate between five per cent and 40 per cent, depending on the specific commodity being produced. An increase in royalties reduces 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; the Corporation's operations are dependent upon the availability of water and its ability to dispose of produced water from drilling and production activities

Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil, liquids and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing have resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity and completely banning hydraulic fracturing in other areas. Any new laws, regulations, or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, and/or 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, liquids and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions or bans on hydraulic fracturing in the areas where the Corporation operates could result in the Corporation being unable to economically recover its oil and gas reserves, which would result in a significant decrease in the value of the Corporation's assets.

Water is an essential component of the Corporation's drilling and hydraulic fracturing processes. Limitations or restrictions on the Corporation's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Corporation is unable to obtain water to use in its operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on its financial condition, results of operations, and cash flows.

In addition, the Corporation must dispose of the fluids produced from oil, NGL and natural gas production operations, including produced water, which it does directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

Injection of produced water into underground formations for disposal purposes has the potential to cause seismic events. A consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Corporation or by commercial disposal well vendors that the Corporation may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Corporation or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Corporation or its vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on the Corporation's business, financial condition, and results of operations.

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

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 – Regulatory Authorities and Environmental 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 liabilities 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 is 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.

Climate Change

Climate change concerns could result in increased operating costs and reduced demand for the Corporation's products and shares, while the potential physical effects of climate change could disrupt the Corporation's production and cause it to incur significant costs in preparing for or responding to those effects

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, NGL and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister made several pledges aimed at reducing Canada's GHG emissions and environmental impact. As discussed below, the Corporation faces both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions, promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, 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, natural gas and related products, resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers to reduce or stop providing insurance coverage to, and commercial and investment banks to reduce or stop financing, oil and natural gas and related infrastructure businesses and projects. The impacts of such efforts require the Corporation's management to dedicate significant time and resources to these climate change-related concerns, may adversely affect the Corporation's operations and the demand for and price of the Corporation's securities, and may negatively impact the Corporation's cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 – Disclosure of Climate Related Matters, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If the Corporation is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation".

Physical risks

Based on the Corporation's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Corporation's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. 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 a wildfire or flood may lead to significant downtime and/or damage to the Corporation's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct of Crew's operations, development, or exploratory activities may negatively impact Crew.

Opposition by Indigenous groups to the conduct of our operations, development, or exploratory activities in any of the jurisdictions in which Crew conducts business may negatively impact it in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact Crew's progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title, and rights to portions of Canada. There are outstanding Indigenous and treaty rights claims, which may include Indigenous title claims, on lands where Crew operates, and such claims, if successful, could have a material adverse impact on its operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect Crew's ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. For example, regulatory authorities in British Columbia temporarily ceased granting approvals, and, in some cases, revoked existing approvals, for, among other things crude oil and natural gas activities relating to drilling, completions, testing, production, and transportation infrastructure following a British Columbia Supreme Court decision that the cumulative impacts of government-sanctioned industrial development on the traditional territories of an Indigenous group in northeast British Columbia breached that group's treaty rights. Following that decision, the Government of British Columbia signed an implementation agreement with that Indigenous group to address cumulative effects of development on that group's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. These measures, which are expected to form the basis of similar arrangements with other Indigenous groups in British Columbia, are expected to remain in place while a long-term cumulative effects management regime is implemented. The long-term impacts of, and associated risks with, the court decision and arrangements with Indigenous groups to address the cumulative effects of development on claimed lands on the Canadian crude oil and natural gas industry and Crew remain uncertain.

In addition, the federal government has introduced legislation to implement the United Nations Declaration on the Rights of Indigenous Peoples ("**UNDRIP**"). Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Inflation and Rising Interest Rates

A failure to secure the services and equipment necessary to the Corporation's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and cash flows

Recently in Canada, the United States and other countries there have been high levels of inflation, supply chain disruptions, equipment limitations and escalating supply costs. These factors have resulted in the escalation of operating costs of the Corporation. The Corporation's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows.

The cost or availability of oil and gas field equipment may adversely affect the Corporation's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available at reasonable prices when required. A failure to secure the services and equipment necessary to the Corporation's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Corporation's financial performance and cash flows.

In addition, many central banks, including the Bank of Canada and U.S. Federal Reserve, have taken steps to raise interest rates in an attempt of combat inflation. The rise in interest rates may impact the Corporation's borrowing costs. Any increase in borrowing costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows of the Corporation. The rising interest rates could also result in a recession in Canada, the United States or other countries in the world. A recession may have a negative impact on demand for oil and natural gas which would result in a decrease in commodity prices. A decrease in commodity prices would immediately impact the Corporation's revenues and cash flows and could also reduce drilling activity on the Corporation's properties. It is unknown how long inflation will continue to impact the economies of Canada and the United States and the impact inflation and rising interest rates will have on demand for oil and gas and commodity prices.

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 may prevent, delay, or make operations more difficult. Consequently, municipalities and provincial transportation departments may 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 of funds available to fund its exploration and development activities, and if applicable, for dividends. Such an increase could also negatively impact the market price of the Common Shares.

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, proceeds from asset sales and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

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

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 those affecting, 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, as well as the repayment of its 2024 Notes, 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 as well as to repay its outstanding debt, including the 2024 Notes. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities, default on outstanding debt and reduce 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.

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, default on outstanding debt 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.

Asset Concentration

The Corporation's operations and drilling activities are vulnerable to risks associated with operating in a limited geographic area

The Corporation's producing and undeveloped properties are geographically concentrated in the province of British Columbia. As a result, demand for and costs of personnel, equipment, power, services, and resources in such geographic area remain high. This high level of demand could result in a delay or inability to secure such personnel, equipment, power, services, and resources. Any delay or inability to secure the personnel, equipment, power, services, or resources could result in crude oil, NGL and natural gas production volumes being below the Corporation's forecasted production volumes. In addition, any such negative effect on production volumes or significant increases in costs could have a material adverse effect on the Corporation's financial conditions, results of operations, cash flow, and profitability.

As a result of this geographical concentration, the Corporation may be disproportionately exposed to the impact of delays or interruptions to operations or production in this area caused by external factors such as governmental regulation, provincial politics, Indigenous rights claims, market limitations, supply shortages, or extreme weather-related conditions.

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. 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 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 have recently increased, but remain volatile as a result of various factors including limited egress options for Western Canadian oil and natural gas producers, global geo-political tensions, 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 its credit facilities. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

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, such financing 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 or derivative contracts 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.

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 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.

The Corporation's insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead the Corporation to decide to reduce or possibly eliminate coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, the Corporation's overall risk exposure could be increased and the Corporation could incur significant costs.

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 from the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences, and direct legal challenges, including the possibility of climate-related litigation. 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 licences 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 are no longer 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.

Dilution

The Corporation may issue additional Common Shares or other dilutive securities, 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 to Shareholders.

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 Licences 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 a licence or lease fails to meet the specific requirement of the 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 those 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.

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.

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 is 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 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, request recipients to send a password or other confidential information through email, or to download malware.

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 may periodically review the web browsing history of its employees and contractors. Despite these efforts, 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.

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. 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.

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, 2022, 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, 2022, 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 other than the credit agreement providing for our Credit Facility and the note indenture in respect of the 2024 Notes. Copies of these agreements are available on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a 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 the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation and regulations.

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 11, 2023. 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.
Suite 800, 250 - 5th Street S.W.
Calgary, Alberta, T2P 0R4
Tel: (403) 266-2088
Fax: (403) 266-6259
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 8th day of March**,** 2023.

(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) "*Karen Nielsen*"
Karen Nielsen
Director and Chair of the Reserves Committee

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

(signed) *"Ryan A. Shay"*
Ryan A. Shay
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, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the 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, 2022, 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 (Country)**	**Audited (M$)**	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule Associates Limited	31-Dec-22	Canada	Nil	3,034,436	Nil	3,034,436

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, 2022)".
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, 2023

(signed) "*Jason Robottom*"
Jason Robottom, P. Eng., CFA
Principal, Energy Advisory

(signed) *"Steven Golko"*
Steven J. Golko, P. Eng.
Senior VP, Reservoir Services

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.