



**ANNUAL INFORMATION FORM  
FOR THE YEAR ENDED DECEMBER 31, 2017**

**March 22, 2018**

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## ABBREVIATIONS

### Oil and Natural Gas Liquids

bbbl	barrel
Mbbbl	thousand barrels
Mmbbl	million barrels
bbbl/d	barrels per day
BOPD	barrels of oil per day
NGLs or ngl's	natural gas liquids

### Natural Gas

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

### Other

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

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

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

## CONVERSIONS

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

## FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. In addition, there are forward-looking statements in this Annual Information Form under the heading: "Statement of Reserves Data and Other Oil and Gas Information" as to our reserves and future net revenues from our reserves, pricing and inflation rates and future development costs, as to the development of our proved undeveloped reserves and probable undeveloped reserves, as to our future development activities, hedging policies, abandonment and reclamation costs, tax horizon, exploration and development activities and production estimates. 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 and natural gas properties; oil and natural gas production levels; the size of the oil 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; and capital expenditure programs.

**Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. In addition, these risks and uncertainties are material factors affecting the success of our business.** Such factors include, but are not limited to: declines in oil 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 and natural gas reserves and resources; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; our reliance on hydraulic fracturing; risks associated with large projects or expansion of our activities; the failure to realize

anticipated benefits of acquisitions and dispositions or to manage growth; changes in climate change laws and other environmental regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling 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 and natural gas; the continuation of the present policies of the Board of Directors relating to management of Crew, capital expenditures and other matters; the continued availability of capital, acquisitions of reserves, undeveloped lands and skilled personnel; the continuation of the current tax and regulatory regime and other assumptions contained in this Annual Information Form.

Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Crew's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website ([www.sedar.com](http://www.sedar.com)) or on Crew's website ([www.crewenergy.com](http://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 prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

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

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

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

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

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

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

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

- (a) in relation to the Corporation's interest in production and reserves, its "company gross reserves", which are the Corporation's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;
- (b) in relation to wells, the total number of wells in which the Corporation has an interest; and
- (c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**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 5, 2018 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2017;

"**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;

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

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

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

**Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2017.**

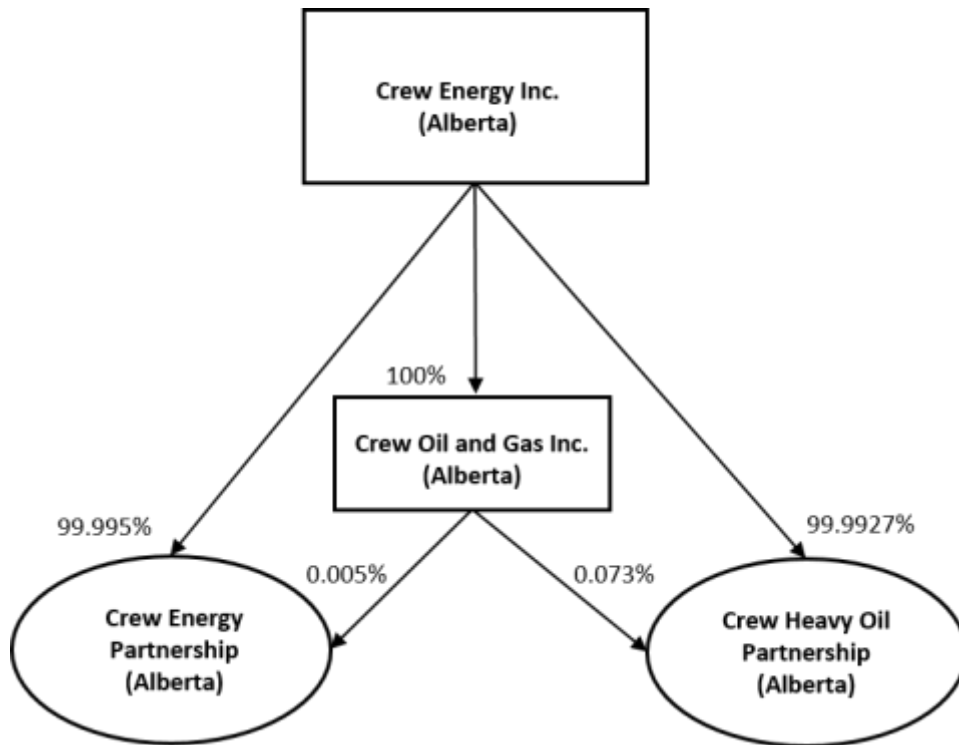
All dollar amounts herein are in Canadian dollars, unless otherwise stated.

## CORPORATE STRUCTURE

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

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

The following diagram describes the inter-corporate relationships among Crew and its material Subsidiaries as at December 31, 2017.



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

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

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



## DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS

### Business Plan and Growth Strategies

The Crew business plan is to create sustainable and profitable growth in the oil and gas industry in western Canada. The following are integral components of Crew's corporate strategy:

- Crew focuses on identifying, acquiring and exploiting large hydrocarbon reservoirs by applying proven and evolving technologies;
- Crew utilizes an annual short and long range planning process with its Board of Directors assessing performance and setting future direction;
- Crew has developed a long range transportation and marketing plan to ensure access to market and diversified pricing exposure, where possible, for the Corporation's oil, natural gas and natural gas liquids production;
- Crew creates and maintains a significant inventory of drilling locations that is refreshed on an annual basis and allows the Corporation to allocate capital on a risked rate of return basis;
- Crew actively manages its portfolio of assets to take advantage of value-enhancing acquisitions and dispositions when market conditions permit;
- Crew monitors its capital structure with a focus on maintaining a strong financial position. This is achieved with regular adjustments to capital spending, hedging of future revenue and costs where possible, the issuance of new equity, issuance of new debt or repayment of existing debt with the proceeds of non-core asset dispositions;
- Crew promotes safe and environmentally responsible operations; and
- Crew values and maintains an entrepreneurial culture to attract and retain high quality staff.

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

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

Crew's management team has a demonstrated track record of bringing together the key components to a successful intermediate exploration and production company including: strong technical skills, expertise in planning and

financial controls, ability to execute on business development opportunities and an entrepreneurial spirit that enables Crew to effectively identify, evaluate and execute on value added initiatives.

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

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

### **Corporate History**

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

Crew has been engaged in the business of exploring for, developing, producing and acquiring crude oil and natural gas in western Canada since it began active operations on September 2, 2003 following completion of the plan of arrangement among the Corporation, Baytex Energy Ltd. and Baytex Energy Trust (the "**Baytex Arrangement**"). At the effective date of the Baytex Arrangement, production from the properties acquired by Crew was approximately 1,500 boe/d comprised of 7.8 Mmcf/d of natural gas production and 200 bbl/d of oil and ngl production. The properties acquired by Crew also included approximately 227,000 net acres of undeveloped land.

In May 2008, the Corporation completed the acquisition of Crown leasehold interests in approximately 102.2 net sections of undeveloped Montney formation rights located in the Corporation's core operating area in northeast British Columbia for approximately \$63 million.

In July 2011, Crew completed the acquisition (the "**Caltex Acquisition**") of Caltex Energy Inc. ("**Caltex**"). The principal properties of Caltex included producing heavy oil properties in the Lloydminster area of Saskatchewan and Alberta and liquids-rich natural gas assets in the Deep Basin area of Alberta. At the time of closing the principal properties of Caltex were producing approximately 10,500 boe/d, comprised of approximately 32% natural gas and 68% heavy oil and ngls and included approximately 137,000 net acres of undeveloped land. The former shareholders of Caltex received in the aggregate approximately 33.6 million Common Shares of Crew in exchange for all of the outstanding shares of Caltex. Crew also assumed approximately \$65.9 million of Caltex's net debt upon closing of the Caltex Acquisition. Following the Caltex Acquisition, Caltex Energy Inc. was amalgamated with Crew and its other wholly-owned subsidiary, Crew Resources Inc., and the two previously wholly-owned subsidiaries of Caltex Energy Inc. were amalgamated to form Crew Oil & Gas Inc, all effective December 31, 2011.

In December 2012, Crew completed the divestiture of a portion of its oil and natural gas assets (the "**Kobes Disposed Assets**") in the Kobes area of northeast British Columbia for gross proceeds of \$108 million, before closing adjustments. The Kobes Disposed Assets comprised approximately 15,800 net acres of liquid rich Montney rights with associated production of approximately 625 boe/d (29% liquids).

During the period December 2012 through July 2013, Crew completed the acquisition of approximately 200 additional net sections of liquids-rich Montney rights contiguous or proximal to Crew's existing Montney lands in northeast British Columbia for aggregate cash consideration of approximately \$77.2 million.

In October 2013, Crew completed the issuance of \$150 million aggregate principal amount of 8.375% senior unsecured notes due October 21, 2020 pursuant to a private placement offering. See "*Description of Capital Structure – Senior Unsecured Notes*".

In the first quarter of 2014, Crew completed two separate transactions that resulted in the Corporation acquiring additional strategic Montney liquids-rich natural gas properties in northeast British Columbia for approximately \$105

million. The acquired assets comprised 75 net sections of land either contiguous with existing Crew land or increasing Crew's working interest in joint interest lands. Pursuant to these transactions, the Corporation acquired approximately 1,400 boe/d of associated production (98% natural gas), under-utilized strategic infrastructure consisting of 130 kilometres of pipeline and over 6,200 hp of field compression.

In May 2014, the Corporation completed the divestiture of certain petroleum and natural gas assets focused primarily in the Deep Basin, Alberta area of operations (the "**Alberta Gas Disposition**"), for cash consideration of approximately \$234 million, before closing adjustments. The divested assets comprised approximately 7,000 boe/d of production (weighted approximately 75% natural gas and 25% light oil and NGLs) as at the date of entering into of the transaction and 254,000 net acres of land. In conjunction with the disposition, the Corporation acquired approximately 400 boe/d of heavy oil production and 2,750 net acres of land located in the Corporation's Lloydminster area of operations for \$12 million.

The Corporation purchased an additional 40 net sections of strategic Montney rights in the third quarter of 2014 for approximately \$17.1 million.

In September 2014, the Corporation completed a further strategic divestiture of its petroleum and natural gas assets in its Princess areas of operations in southeast Alberta for total cash consideration of approximately \$150 million, before closing adjustments (the "**Princess Disposition**"). The divested assets comprised approximately 3,650 boe/d of production (weighted approximately 78% oil and NGLs and 22% natural gas) at the date of entering into the transaction and 259,234 net acres of petroleum and natural gas rights.

In March 2015, the Corporation completed a bought deal short form prospectus offering of 16,667,000 Common Shares at an issue price of \$6.00 per share for aggregate gross proceeds of approximately \$100 million.

In July 2015, the Corporation completed a petroleum and natural gas rights exchange with the province of British Columbia, adding 53 net sections of new Montney land contiguous to the Corporation's Groundbirch property in exchange for surrendering 66 net sections of undeveloped land that had been subject to restricted development since 2004.

In September 2015, the Corporation completed the strategic divestiture of a minor portion of its Lloydminster, Alberta heavy oil assets for cash consideration of approximately \$50 million, before closing adjustments (the "**Lloydminster Disposition**"). The divested assets comprised approximately 225 boe/d of heavy oil production as at the date of completion of the transaction, 1.0 mmmboe of proved plus probable reserves as assigned by Sproule effective December 31, 2014 and 11,670 net acres of petroleum and natural gas rights.

The Corporation's firm transportation arrangement on the Alliance pipeline system became effective on December 1, 2015, securing 100 Mmcf per day of zone 2 firm receipt service and 25 Mmcf per day of zone 2 priority interruptible service that provides take away capacity to alternative markets, enabling the Corporation to capture more favorable pricing.

Throughout 2016, the Corporation continued to demonstrate the success of its Montney focused strategy with positive growth across its core Greater Septimus area, and advancement of its future development plans at Groundbirch. While commodity prices remained very weak through the first half of 2016, the Corporation benefited from lower costs and improved operational efficiencies and had access to required drilling and completion services. The Corporation's success at Greater Septimus continued through 2016 with area production increasing 59% year over year. The Corporation also reported strong Montney reserves growth in the Sproule Report with attractive capital efficiencies.

The Corporation improved its financial flexibility in 2017, while continuing to focus operationally on its liquids-rich Montney strategy. In March 2017, Crew completed the issuance of \$300 million aggregate principal amount of 6.500% senior unsecured notes due March 14, 2024 pursuant to a private placement offering. In conjunction therewith, Crew completed the redemption of its previously outstanding 8.375% senior unsecured notes. See "*Description of Capital Structure – Senior Unsecured Notes*". During the second quarter of 2017 Crew completed the

disposition of 18,400 net acres of undeveloped land in the Goose area of northeast British Columbia for \$49 million. The assets disposed of included no production or assigned reserves.

Field activity in 2017 was focused at the Greater Septimus area, where Crew continued to delineate the ultra liquids-rich resource at West Septimus and completed a facility expansion to 120 Mmcf per day. In aggregate, Crew's capital expenditures totaled \$238 million in 2017. The Corporation drilled 35 (33.2 net) wells, increasing reserves per share by approximately 28% on a proved developed producing basis, 9% on a total proved basis and 12% on a total proved plus probable basis. Production volumes during the fourth quarter averaged approximately 25,270 boe per day, a 13% increase relative to the same period in 2016.

### **Competitive Conditions**

The oil and natural gas industry is intensely competitive in all its phases. Crew competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the transportation and marketing of oil, ngls and natural gas. Crew's competitors include resource companies which have greater financial resources, staff and facilities than those of Crew. Competitive factors in the distribution and marketing of oil, ngls and natural gas include price along with the method 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 and natural gas production. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on, among other things, the Corporation's revenues and financial condition. Commodity prices declined significantly in 2015 and 2016 with continued volatility through 2017 and into early 2018. See "*Risk Factors – Weakness in the Oil and Gas Industry*" and "*Risk Factors – Prices, Markets and Marketing*".

## **SIGNIFICANT ACQUISITIONS**

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

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

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated February 5, 2018. The effective date of the Statement is December 31, 2017 and the preparation date of the Statement was March 16, 2018. 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, 2017 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, certain 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 and, specifically, in the provinces of British Columbia, Saskatchewan and Alberta.

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

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

**Reserves Data (Forecast Prices and Costs)**

**SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2017**

RESERVES CATEGORY	RESERVES SUMMARY									
	LIGHT CRUDE OIL & MEDIUM CRUDE OIL		HEAVY CRUDE OIL		NATURAL GAS LIQUIDS		CONVENTIONAL NATURAL GAS		TOTAL OIL EQUIVALENT	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mboe)	Net (Mboe)
PROVED										
Developed Producing	387	358	1,459	1,346	9,761	8,171	290,587	234,927	60,037	49,030
Developed Non-Producing	19	17	1,541	1,336	377	331	12,791	11,226	4,068	3,555
Undeveloped	1,404	1,123	1,383	1,280	21,265	17,689	487,307	389,824	105,270	85,063
TOTAL PROVED	1,809	1,499	4,382	3,962	31,403	26,191	790,685	635,978	169,376	137,648
TOTAL PROBABLE	10,718	9,097	3,957	3,387	37,476	30,817	892,089	710,790	200,832	161,766
TOTAL PROVED PLUS PROBABLE	12,527	10,595	8,339	7,350	68,879	57,008	1,682,774	1,346,768	370,208	299,414

**Note:**

- (1) Columns may not add due to rounding.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
PROVED										
Developed Producing	1,073,088	779,906	614,473	511,139	440,987	1,059,146	776,005	613,299	510,762	440,858
Developed Non-Producing	74,537	60,428	50,860	43,962	38,736	54,358	52,772	47,808	42,689	38,182
Undeveloped	1,797,035	959,791	569,520	361,626	239,164	1,304,344	706,058	422,483	269,473	178,152
TOTAL PROVED	2,944,659	1,800,125	1,234,854	916,727	718,886	2,417,848	1,534,836	1,083,590	822,924	657,192
TOTAL PROBABLE	4,467,953	2,168,642	1,258,618	809,363	554,894	3,255,627	1,566,202	896,156	567,033	382,231
TOTAL PROVED PLUS PROBABLE	7,412,612	3,968,766	2,493,472	1,726,091	1,273,781	5,673,475	3,101,038	1,979,746	1,389,956	1,039,424

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2017**

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES <sup>(2)</sup> (M\$)	OPERATING COSTS (M\$)	DEVELOPMENT COSTS (M\$)	ABANDONMENT AND RECLAMATION COSTS <sup>(1)</sup> (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Total Proved	6,672,390	1,047,039	1,873,178	729,671	77,842	2,944,659	526,812	2,417,848
Total Proved Plus Probable	15,984,576	2,565,800	4,106,288	1,764,176	135,699	7,412,612	1,739,138	5,673,475

**Notes:**

- (1) Reflects estimated abandonment and reclamation costs for all wells that have been attributed reserves and includes material dedicated processing facilities. Does not include abandonment and reclamation costs for wells with no attributed reserves. See "Further Information Regarding Abandonment and Reclamation Costs".
- (2) Royalties include Saskatchewan Capital Surtax.

**FUTURE NET REVENUE  
BY PRODUCT TYPE  
AS OF DECEMBER 31, 2017**

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES <sup>(3)</sup> (discounted at 10%/year) (M\$)	UNIT VALUE BEFORE INCOME TAXES <sup>(4)</sup> (discounted at 10%/year) (Units as noted)
Proved Producing	Light Crude Oil and Medium Crude Oil <sup>(1)</sup>	12,836	12.08 per boe
	Heavy Crude Oil <sup>(1)</sup>	25,323	18.74 per boe
	Conventional Natural Gas <sup>(2)</sup>	576,314	2.06 per mcfe
Total Proved	Light Crude Oil and Medium Crude Oil <sup>(1)</sup>	13,211	12.23 per boe
	Heavy Crude Oil <sup>(1)</sup>	68,892	17.34 per boe
	Conventional Natural Gas <sup>(2)</sup>	1,152,751	1.45 per mcfe
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil <sup>(1)</sup>	96,118	5.92 per boe
	Heavy Crude Oil <sup>(1)</sup>	133,138	18.09 per boe
	Conventional Natural Gas <sup>(2)</sup>	2,264,216	1.37 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 certainty.
  - (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to 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 qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

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, 2017 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 and natural gas benchmark reference pricing, as at December 31, 2017, 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, 2017  
FORECAST PRICES AND COSTS**

Year	OIL			ALBERTA NGLS			NATURAL GAS		CAPITAL INFLATION RATE %/Year	OPERATING INFLATION RATE <sup>(1)</sup> %/Year	EXCHANGE RATE <sup>(2)</sup> (\$US/\$Cdn)
	WTI Cushing @ Oklahoma (\$US/bbl)	LIGHT, SWEET OIL @ Edmonton (40 °API, 0.3% S) (\$Cdn/bbl)	Western Canada Select (WCS) 20.5 °API (\$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)			
Forecast											
2018	55.00	65.44	51.05	26.06	48.73	67.72	2.85	2.45	0.0	0.0	0.790
2019	65.00	74.51	59.61	32.84	55.49	75.61	3.11	2.71	2.0	2.0	0.820
2020	70.00	78.24	64.94	35.41	57.65	78.82	3.65	3.25	2.0	2.0	0.850
2021	73.00	82.45	68.43	37.85	60.12	82.35	3.80	3.40	2.0	2.0	0.850
2022	74.46	84.10	69.80	39.29	61.32	84.07	3.95	3.55	2.0	2.0	0.850
2023	75.95	85.78	71.20	40.25	62.55	85.82	4.05	3.65	2.0	2.0	0.850
2024	77.47	87.49	72.62	41.23	63.80	87.61	4.15	3.75	2.0	2.0	0.850
2025	79.02	89.24	74.07	42.23	65.07	89.43	4.25	3.85	2.0	2.0	0.850
2026	80.60	91.03	75.55	43.26	66.37	91.29	4.36	3.96	2.0	2.0	0.850
2027	82.21	92.85	77.06	44.30	67.70	93.19	4.46	4.06	2.0	2.0	0.850
2028	83.85	94.71	78.61	45.36	69.06	95.12	4.57	4.17	2.0	2.0	0.850
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr			

**Notes:**

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

Weighted average historical prices realized by the Corporation for the year ended December 31, 2017, were \$3.01/mcf for conventional natural gas, \$58.34/bbl for light/medium crude oil, \$45.14/bbl for heavy crude oil at Lloydminster and \$45.69/bbl for natural gas liquids.

4. Well abandonment and reclamation costs have been included for developed and undeveloped locations with reserves assigned and include material dedicated processing facilities and facility expansions.
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 <sup>(1)</sup> RESERVES BY PRINCIPAL PRODUCT TYPE  
FORECAST PRICES AND COSTS**

FACTORS	LIGHT CRUDE OIL & MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
December 31, 2016	1,376	11,165	12,540	5,068	4,877	9,944	29,678	29,012	58,690
Extensions & Improved									
Recovery	-	-	-	8	3	11	1,305	11,234	12,539
Infill Drilling	-	-	-	48	10	58	-	-	-
Technical Revisions	612	(474)	138	34	(997)	(963)	1,746	(2,763)	(1,016)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	(4)	(10)	(14)
Economic Factors	3	28	30	(105)	64	(41)	(1)	2	2
Production	(181)	-	(181)	(670)	-	(670)	(1,322)	-	(1,322)
December 31, 2017	1,809	10,718	12,527	4,382	3,957	8,339	31,403	37,476	68,879
FACTORS	CONVENTIONAL NATURAL GAS			OIL EQUIVALENT					
	Gross Proved (Mmcf)	Gross Probable (Mmcf)	Gross Proved Plus Probable (Mmcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)			
December 31, 2016	702,517	754,096	1,456,612	153,207	170,736	323,943			
Extensions & Improved									
Recovery	40,517	211,386	251,903	8,066	46,468	54,534			
Infill Drilling	-	-	-	48	10	58			
Technical Revisions	93,137	(53,001)	40,136	17,915	(13,067)	4,848			
Discoveries	-	-	-	-	-	-			
Acquisitions	-	-	-	-	-	-			
Dispositions	(7,683)	(20,363)	(28,046)	(1,284)	(3,404)	(4,688)			
Economic Factors	(337)	(28)	(365)	(159)	89	(70)			
Production	(37,466)	-	(37,466)	(8,417)	-	(8,417)			
December 31, 2017	790,685	892,089	1,682,775	169,376	200,832	370,208			

**Notes:**

- (1) Gross Reserves in the tables above are the Corporation's interest share before deduction of royalties and without including any royalty interests of the Corporation.
- (2) Increases to Extensions & Improved Recovery are the result of step-out locations drilled by Crew, as well as reserves associated with heavy oil waterfloods. Reserves additions for Extensions and Improved Recovery are combined and reported as "Extensions & Improved Recovery".
- (3) Columns may not add due to rounding.

## Additional Information Relating to Reserves Data

### Undeveloped Reserves

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 7 of this AIF.

#### Proved Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbbl)		Heavy Crude Oil (Mbbbl)		Conventional Natural Gas (Mmcf)		NGLs (Mbbbl)	
	First	Booked at	First	Booked at	First	Booked at	First	Booked at
	Attributed	Year End	Attributed	Year End	Attributed	Year End	Attributed	Year End
2015	-	1,372.8	189.9	1,670.7	25,113	357,690	1,083.6	14,088.3
2016	326.9	1,033.1	38.3	1,782.5	148,345	474,387	9,094.6	21,965.1
2017	-	1,403.9	-	1,383.2	28,705	487,307	1,202.9	21,265.1

#### Probable Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbbl)		Heavy Crude Oil (Mbbbl)		Conventional Natural Gas (Mmcf)		NGLs (Mbbbl)	
	First	Booked at	First	Booked at	First	Booked at	First	Booked at
	Attributed	Year End	Attributed	Year End	Attributed	Year End	Attributed	Year End
2015	-	7,574.3	144.9	2,862.8	191,130	556,571	8,536.3	20,299.7
2016	3,821.0	11,017.2	172.4	3,079.1	139,965	678,460	7,832.8	26,467.0
2017	-	10,560.6	-	2,211.9	218,239	793,766	12,393.8	34,025.6

Current industry technology and significant capital expenditures are required to bring these undeveloped reserves into production. Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The pace of development of the proved and probable undeveloped reserves (both in 2018 and 2019 as well as in years beyond 2019) is influenced by many factors, including the outcomes of the yearly drilling and reservoir evaluations, the price for oil and natural gas and a variety of economic factors and conditions.

In some cases it will take longer than three years to develop these reserves. There are a number of factors that could result in delayed or deferred development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations or changing regulation and/or fiscal policy); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion from a separate zone is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access, issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "Risk Factors – Exploration, Development and Production Risks".

***Significant Factors or Uncertainties Affecting Reserves Data***

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, 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 our northeast British Columbia geographic area of operations. As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative. Degradation in future commodity price forecasts relative to the forecast in the Sproule Report can also have a negative impact on the economics and timing of development of undeveloped reserves, unless significant reduction in the future costs of development are realized.

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

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

***Further Information Regarding Abandonment and Reclamation Costs***

The Sproule Report includes an undiscounted estimate for abandonment and reclamation costs of \$135.7 million (\$119 million of which extends past 35 years) for total proved plus probable reserves (approximately \$8.1 million, discounted at 10%) at December 31, 2017. In the Sproule Report, abandonment and reclamation costs represent all costs associated with the process of restoring a company's properties, which have been disturbed by oil and gas activities, to a standard imposed by applicable government or regulatory authorities. The costs included in the Sproule Report do not represent the total decommissioning liabilities of the Corporation but only abandonment and reclamation cost obligations for the properties that have been assigned reserves and for dedicated facilities required to produce these reserves. The estimate in the Sproule Report includes abandonment and reclamation costs associated with future development activities including all development drilling, and material dedicated gathering and processing facility expansions or builds, required to produce the reserves included in the Sproule Report.

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

<b>Abandonment and Reclamation Costs</b>	<b>Undiscounted (\$M)</b>
Existing wells with developed reserves and associated facilities	39,540
Future wells with undeveloped reserves and associated facilities	96,159
<b>Total abandonment and reclamation costs for developed and undeveloped reserves</b>	<b>135,699</b>

In addition to the above, the Corporation has estimated undiscounted total abandonment and reclamation costs of \$42.4 million related to existing properties and associated facilities that were not assigned reserves in the Sproule Report. The estimate for abandonment and reclamation costs are 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 expects to incur abandonment and reclamation costs on approximately 1,123 gross (913 net) existing wells.

Crew has not established a reclamation fund to pay future asset retirement obligation costs. Crew expects to incur approximately \$14.0 million (\$12.8 million, discounted at 10%) in the next three years in respect of its abandonment and reclamation costs. The future asset retirement obligation is reviewed regularly by management based upon current regulations, costs, technologies and industry standards.

#### ***Future Development Costs***

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

<b>Year</b>	<b>Forecast Prices and Costs</b>	
	<b>Proved Reserves (MM\$)</b>	<b>Proved Plus Probable Reserves (MM\$)</b>
2018	90	143
2019	140	224
2020	74	241
2021	135	374
2022	93	231
Thereafter	198	551
<b>Total Undiscounted</b>	<b>730</b>	<b>1,764</b>

The Corporation currently expects that the capital listed in the preceding table will be funded through a combination of sources including internally generated funds 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 funds from operations.

## Other Oil and Gas Information

### *Principal Properties*

Crew's operations are primarily focused on the development and growth of its Montney oil, liquids and condensate-rich natural gas assets in northeast British Columbia. In addition, the Corporation maintains its heavy oil assets in the Lloydminster area. The northeast British Columbia geographic area is made up of five areas: Septimus, West Septimus, Groundbirch/Monias, Attachie and Tower. Crew has currently budgeted 2018 net capital expenditures of \$80 to 85 million, with predominant focus on the development of Ultra condensate-rich ("UCR") and liquids-rich natural gas from the Montney formation at West Septimus, and continued development of the infrastructure in the West Septimus and Groundbirch areas.

The following is a description of Crew's principal properties, plants, facilities and installations as at December 31, 2017. Production stated is production before deduction of royalties and includes royalty interests to Crew and, unless otherwise stated, is average production for 2017. Reserve amounts are total proved plus probable reserves based on forecast prices and costs, stated before deduction of royalties and without including any royalty interest of the Corporation as at December 31, 2017 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, 2017.

### **West Septimus, British Columbia**

The West Septimus area is located approximately 21 kilometers 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 developed with long reach horizontal wells that are completed with multi-stage water-based fracture stimulations. Crew's production from this area in 2017 averaged 9,652 boe/d weighted 77% to natural gas, 14% condensate and 9% to other liquids. At December 31, 2017, the Corporation had 58 (58.0 net) producing liquids-rich natural gas wells. The Corporation's current production is processed through Crew's operated West Septimus facility owned 28.7% by the Corporation. In 2017, Crew drilled thirty-two (30.2 net) and completed twenty-four (24.0 net) gas wells. In 2017, Crew completed construction of a wholly owned sales gas pipeline from West Septimus to Crew's Septimus facility. In 2018, Crew plans to drill four (4.0 net) wells and complete 15 (13.2 net) wells in the area.

During 2017, the Corporation completed the expansion of the West Septimus facility from 60 Mmcf per day to 120 Mmcf per day, jointly with an infrastructure partner who participated for a 72% share in the expansion. The plant was commissioned on time and 8% under budget in early November. In early 2018, Crew began construction on a pipeline from the West Septimus facility through Groundbirch to tie the facility into the Saturn meter station on the TransCanada Pipeline System. This project will afford flexibility to meet the majority of the transportation arrangements through 2019 without additional processing capacity at Groundbirch. The pipeline is expected to be concluded in the third quarter of 2018.

As at December 31, 2017, the Sproule Report assigned proved plus probable reserves of 44,593.6 Mbbl of NGLs and 905,673 Mmcf of natural gas to Crew's interests in the West Septimus area. At year-end 2017, the Corporation owned 29,799 net acres of land with an average working interest of 86.34% in the area.

**Septimus, British Columbia**

The Septimus area is located approximately 13 kilometers southwest of Fort St. John in British Columbia. Crew's operations include liquids-rich natural gas from the Montney formation. At December 31, 2017, Crew had an interest in 69 (64.7 net) producing liquids-rich natural gas wells and two (2.0 net) service wells in the area. In 2017, production averaged 8,193 Boe/d weighted 85% to natural gas, 8% condensate and 7% to other liquids. Crew drilled a total of one (1.0 net) and completed five (5.0 net) gas wells in the area in 2017. Production from the Montney is processed through a facility operated by the Corporation and in which Crew currently owns a 28.7% working interest. Due to the current low price of natural gas in Canada, Crew plans to focus its 2018 capital expenditures on the West Septimus area where production includes a larger percentage of higher valued condensate. The Company currently has no plans to drill or complete wells in the Septimus area in 2018.

As at December 31, 2017, the Sproule Report assigned total proved plus probable reserves of 16,708.6 Mbbl of oil and NGLs along with 393,068 Mmcf of natural gas to Crew's interests in the Septimus area. At year-end 2017, the Corporation owned 13,573 net acres of land with an average working interest of 90.46% in this area.

**Tower, British Columbia**

The Tower area is located approximately 13 kilometers south of Fort St. John, British Columbia. Crew's operations include oil and liquids-rich solution gas from the Montney formation. In 2017, Crew's production from the area averaged 1,229 boe/d weighted 46% to oil and natural gas liquids. At December 31, 2017, the Corporation had eleven (9.7 net) producing oil wells. In 2017, Crew completed two (2.0 net) oil wells at Tower that had been drilled in late 2014 and early 2015. Crew's gas production in the Tower area is processed through the Crew owned Septimus gas facility and the oil production is trucked clean to market from a 100% Crew owned and operated oil processing facility. During Q1 2018, a strategic partner is expected to complete construction of a water handling facility at Tower in which Crew will be the anchor tenant. Increased water handling capacity is expected to reduce operating costs and support future development in the area.

As at December 31, 2017, the Sproule Report assigned proved plus probable reserves of 9,871.1 Mbbl of oil and ngl's and 52,376 Mmcf of natural gas to Crew's interests in the Tower area. At year-end 2017, the Corporation owned 32,256 net acres of land with an average working interest of 83.28% in the area.

**Groundbirch/Monias, British Columbia**

The Groundbirch/Monias area is located approximately 35 km southwest of Fort St. John, British Columbia and includes lands adjacent to and southwest of West Septimus. Crew's operations in this area include liquids-rich natural gas production from the Montney, Halfway and Belloy formations. In 2017, the Corporation's production from this area averaged 1,876 boe/d weighted 95% to natural gas. At December 31, 2017, the Corporation had 13 (12.7 net) producing natural gas wells. In 2017, Crew drilled two (2.0 net) and completed two (2.0 net) gas wells. Currently, all of the Corporation's production in the Groundbirch/Monias area is processed through third party facilities.

As at December 31, 2017, the Sproule Report assigned proved plus probable reserves of 6,509.3 Mbbl of oil and ngl's and 233,897 Mmcf of natural gas to Crew's interests in the Groundbirch/Monias area. At year-end 2017, the Corporation owned 130,527 net acres of land with an average working interest of 81% in the area.

**Attachie, British Columbia**

The Attachie area is located approximately 59 kilometers west of Fort St. John in British Columbia. Crew's operations target liquids-rich natural gas from the Montney formation. At December 31, 2017, the Corporation had no producing gas wells or oil wells in this area. The Attachie area is a future development area for the Corporation that had no activity in 2017.

As at December 31, 2017, the Sproule Report assigned proved plus probable reserves of 3,490.4 Mbbbl of oil and ngls and 91,852 Mmcf of natural gas to Crew's interests in the Attachie area. At year-end 2017, the Corporation owned 30,247 net acres of land with an average working interest of 96% in the area.

**Lloydminster, Saskatchewan/Alberta**

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

At December 31, 2017 the Corporation owned 120 (104 net) producing oil wells and 11 (10 net) service wells, along with a 100% owned oil battery and numerous single and multi-well batteries located at individual well sites. In 2017, Crew drilled five (5.0 net) well in the area resulting in four (4.0 net) oil wells. Production for 2017 averaged 1,841 boe/d weighted 99% to oil and liquids. The majority of the Corporation's oil production from the Lloydminster area is gathered and processed at the Corporation's 100% owned oil battery which is directly tied into the Manito Pipeline System. The Corporation has commenced a process to sell its Lloydminster assets which is on-going.

As at December 31, 2017, the Sproule Report assigned proved plus probable reserves of 8,339.3 mbbbl of oil and ngls and 74 Mmcf of natural gas to Crew's interests in the Lloydminster area. At year-end 2017, the Corporation owned 62,457 net acres of land with an average working interest of 93% 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 270 boe/d of production in 2017. As at December 31, 2017, the Corporation owned two (0.5 net) producing oil wells and 23 (7.3 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, 2017.

	<b>Oil Wells</b>				<b>Natural Gas Wells</b>			
	<b>Producing</b>		<b>Non-Producing</b>		<b>Producing</b>		<b>Non-Producing</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
Alberta	45	44	106	106	-	-	8	7
British Columbia	13	10	8	4	163	143	191	93
Saskatchewan	75	60	355	310	-	-	12	10
<b>Total</b>	<b>133</b>	<b>114</b>	<b>469</b>	<b>420</b>	<b>163</b>	<b>143</b>	<b>211</b>	<b>110</b>

**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, 2017.

	<b>Developed Acres</b>		<b>Undeveloped Acres</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
Alberta	9,639	7,843	14,726	11,580
British Columbia	152,492	78,917	383,194	306,696
Saskatchewan	0	0	376,920	41,235
Other Canada	18,159	14,931	35,444	35,074
<b>Total</b>	<b>180,290</b>	<b>101,691</b>	<b>810,283</b>	<b>394,585</b>

Of the Corporation's undeveloped land, the rights to explore develop and exploit 8,439 net acres may expire by December 31, 2018 if the Corporation takes no action to retain the land. Crew plans to submit applications to continue selected portions of this acreage.

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

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

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

### **Forward Contracts and Marketing**

With the exception of the following financial derivative contracts entered into pursuant to the Corporation's risk management program, as of December 31, 2017, Crew does not have any material commitments to buy or sell natural gas or crude oil production.

As at December 31, 2017, the Corporation held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded	Fair Value
Gas	5,000 gj/day	Jan 1, 2018 - Dec 31, 2018	AECO C Monthly Index	\$3.00/gj	Call	(\$20)
Gas	2,500 gj/day	Jan 1, 2018 - Dec 31, 2018	AECO C Daily Index	\$2.62/gj	Swap	956
Gas	17,500 mmbtu/day	Jan 1, 2018 - Dec 31, 2018	Chicago Citygate	\$3.64/mmbtu	Swap	1,632
Gas	5,000 mmbtu/day	Jan 1, 2018 - Dec 31, 2018	US\$ Nymex Henry Hub	\$3.05 US/mmbtu	Swap	474
Propane	400 bbl/day	Jan 1, 2018 - Dec 31, 2018	US\$ Conway OPIS	\$0.79 US/gal	Swap	(\$181)
Oil	1,500 bbl/day	Jan 1, 2018 - Dec 31, 2018	CDN\$ WTI	\$70.94/bbl	Swap	(\$1,856)
Oil	250 bbl/day	Jan 1, 2018 - Dec 31, 2018	CDN\$ WTI	\$60.00 - \$69.65/bbl	Collar <sup>(1)</sup>	(\$520)
Oil	250 bbl/day	Jan 1, 2018 - Dec 31, 2018	CDN\$ WTI	\$69.00 - \$74.25/bbl	Collar <sup>(2)</sup>	(\$138)
<b>Total</b>						<b>\$347</b>

**Notes:**

- (1) The referenced contract is a costless collar whereby the Corporation receives \$60/bbl when the market price is below \$60/bbl, and receives \$69.65/bbl when the market price is above \$69.65/bbl.
- (2) The referenced contract is a costless collar whereby the Corporation receives \$69/bbl when the market price is below \$69/bbl, and receives \$74.25/bbl when the market price is above \$74.25/bbl.

### **Pipeline Transportation and Production Processing Commitments**

As part of normal business operations, the Corporation has entered into firm-service agreements for the processing and transportation of natural gas, NGLs and oil. Crew renews or amends existing agreements and enters into new agreements from time-to-time based on forecast capacity requirements.

Over the next five years, the Corporation's transportation commitments and processing commitments exceed forecast production volumes of Crew's proved reserves in the Sproule Report by an average of approximately 5.8 Mmcf per day and approximately 29.6 Mmcf per day, respectively. If Crew's sales volumes were equivalent to the forecast production of proved reserves, the aggregate fees in respect of the differences described above would average approximately \$6.5 million per year over the next five years. The Corporation's transportation commitments and processing commitments each are less than forecast production of the Corporation's proved plus probable reserves in the Sproule Report over the next five years.

The production, processing and transportation of natural gas, NGLs 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, 2017, which can be found under Crew's profile on SEDAR at [www.sedar.com](http://www.sedar.com).

### **Tax Horizon**

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2017. 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 2018 and does not anticipate being in a cash income tax payable situation through 2020 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, 2017:

	(\$ thousands)
Property acquisition costs	
Proved properties	3,827
Unproved properties	3,508
Exploration costs	357
Development costs	234,437
Corporate acquisitions	-
Property dispositions	(51,733)
<b>Total</b>	<b>190,396</b>

### **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, 2017.

	Gross			Net		
	Exploration	Development	Total	Exploration	Development	Total
Crude Oil	-	4	4	-	4	4
Natural Gas	-	35	35	-	33.2	33.2
Dry <sup>(1)</sup>	-	1	1	-	1	1
Service <sup>(2)</sup>	-	-	-	-	-	-
Stratigraphic Test	-	-	-	-	-	-
<b>Total:</b>	<b>-</b>	<b>40</b>	<b>40</b>	<b>-</b>	<b>38.2</b>	<b>38.2</b>

#### **Notes:**

- (1) "Dry well" means a well which is not a productive well or a service well. A productive well is a well which is capable of producing oil and gas in commercial quantities or in quantities considered by the operator to be sufficient to justify the costs required to complete, equip and produce the well.
- (2) A service well means a well such as a water or gas-injection, water-source or water-disposal well. Such wells do not have marketable reserves of crude oil or natural gas attributed to them but are essential to the production of the crude oil and natural gas reserves.

In 2018, the Corporation intends to continue to focus on the development of its northeast British Columbia Montney assets including liquids-rich natural gas at Greater Septimus, particularly the liquids and ultra condensate-rich areas at West Septimus. The Corporation is currently budgeting for a net \$80 to \$85 million capital expenditure program in 2018, which is expected to be financed through cash flow from operations and, if required, draws on the Corporation's bank facility. It is currently the Corporation's intention to monitor commodity prices and their impact on 2018 cash flow and, if necessary, adjust capital expenditures to maintain its financial strength.

For details on Crew's important current and likely exploration and development activities during 2018, 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, 2018 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*".

Reserves Category	Light Crude Oil and Medium Crude Oil		Heavy Crude Oil		Natural Gas Liquids		Conventional Natural Gas		Total Oil Equivalent	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(bbl/d)	(bbl/d)	(bbl/d)	(bbl/d)	(bbl/d)	(bbl/d)	(Mcf/d)	(Mcf/d)	(Boe/d)	(Boe/d)
Total Proved										
Septimus	0	0	0	0	1,542	1,357	44,668	39,000	8,987	7,857
West Septimus	0	0	0	0	3,004	2,795	75,685	70,375	15,618	14,525
Other	275	241	2,282	2,019	197	171	13,085	11,844	4,934	4,405
Total Proved Plus Probable										
Septimus	0	0	0	0	1,704	1,498	48,389	42,373	9,768	8,560
West Septimus	0	0	0	0	4,094	3,725	101,112	93,981	20,946	19,388
Other	337	292	3,004	2,651	141	193	14,381	13,052	5,878	5,311

**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 2018 production as reflected in the Sproule Report.

### Production History

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

	Quarter Ended			
	2017			
	Dec. 31	Sept. 30	Jun. 30	Mar. 31
<b>Average Daily Production<sup>(1)</sup></b>				
Light Crude Oil and Medium Crude Oil (bbl/d)	399	553	499	530
Heavy Crude Oil (bbl/d)	1,808	1,902	1,778	1,857
Conventional Natural Gas (Mcf/d)	111,737	102,046	91,828	104,887
NGLs (bbl/d)	4,440	3,788	2,886	3,363
Combined (BOE/d)	25,270	23,251	20,468	23,231
<b>Average Price Received</b>				
Light Crude Oil and Medium Crude Oil (\$/bbl)	64.91	52.47	58.14	59.74
Heavy Crude Oil (\$/bbl)	48.73	43.91	45.05	42.93
Conventional Natural Gas (\$/Mcf) <sup>(2)</sup>	2.64	2.51	3.45	3.54
NGLs (\$/bbl)	55.22	39.80	38.66	45.71
Combined (\$/BOE) <sup>(2)</sup>	25.87	22.36	26.25	27.40
<b>Transportation Expenses</b>				
Light Crude Oil and Medium Crude Oil (\$/bbl)	1.88	5.11	2.60	1.76
Heavy Crude Oil (\$/bbl)	1.00	0.92	0.93	0.98
Conventional Natural Gas (\$/Mcf)	0.41	0.42	0.55	0.45
NGLs (\$/bbl)	0.16	0.79	1.14	0.85
Combined (\$/BOE)	1.94	2.18	2.75	2.29
<b>Royalties Paid</b>				
Light Crude Oil and Medium Crude Oil (\$/bbl)	9.92	8.27	11.12	9.42
Heavy Crude Oil (\$/bbl)	5.60	5.59	5.11	5.87
Conventional Natural Gas (\$/Mcf)	0.12	0.08	0.19	0.26
NGLs (\$/bbl)	2.75	2.71	3.40	2.02
Combined (\$/BOE)	1.59	1.43	2.06	2.18
<b>Operating Expenses</b>				
Light Crude Oil and Medium Crude Oil (\$/bbl)	36.12	21.00	20.76	14.52
Heavy Crude Oil (\$/bbl)	22.15	22.57	20.04	22.53
Conventional Natural Gas (\$/Mcf)	0.69	0.67	0.73	0.60
NGLs (\$/bbl)	3.82	3.58	4.34	3.61
Combined (\$/BOE)	5.90	5.86	6.15	5.38
<b>Netback Received<sup>(3)</sup></b>				
Light Crude Oil and Medium Crude Oil (\$/bbl)	16.99	18.09	23.66	34.04
Heavy Crude Oil (\$/bbl)	19.98	14.83	18.97	13.55
Conventional Natural Gas (\$/Mcf)	1.42	1.34	1.98	2.23
NGLs (\$/bbl)	48.49	32.72	29.78	39.23
Combined (\$/BOE)	16.44	12.89	15.29	17.55

#### 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.

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, 2017:

	<b>Light Crude Oil &amp; Medium Crude Oil (bbl/d)</b>	<b>Heavy Crude Oil (bbl/d)</b>	<b>Conventional Natural Gas (Mcf/d)</b>	<b>NGLS (bbl/d)</b>	<b>Oil Equivalent (BOE/d)</b>
Lloydminster Alberta	-	912	27	-	917
<b>Total Alberta</b>	-	<b>912</b>	<b>27</b>	-	<b>917</b>
Septimus	-	-	41,796	1,227	8,193
West Septimus	-	-	44,886	2,171	9,652
Other	495	-	15,932	225	3,375
<b>Total British Columbia</b>	<b>495</b>	-	<b>102,614</b>	<b>3,623</b>	<b>21,220</b>
Lloydminster Saskatchewan	-	924	1	-	924
<b>Total Saskatchewan</b>	-	<b>924</b>	<b>1</b>	-	<b>924</b>
<b>Total</b>	<b>495</b>	<b>1,836</b>	<b>102,642</b>	<b>3,623</b>	<b>23,061</b>

For the year ended December 31, 2017, approximately 47% of Crew's gross production revenue was derived from crude oil and natural gas liquids production and 53% was derived from 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 in the foreseeable future but will review that policy from time to time as circumstances warrant. Crew currently intends to retain future earnings, if any, for future operations, growth and debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board of Directors and will depend on, among other things, the Corporation's results of operations, current and anticipated cash requirements and surplus, financial condition, solvency tests imposed by corporate law, contractual restrictions and financing agreement covenants, if any, and other factors that the Board may determine relevant.

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

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

#### DESCRIPTION OF CAPITAL STRUCTURE

##### Share Capital

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

##### Common Shares

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

## Senior Unsecured Notes

On October 21, 2013, the Corporation completed a private placement offering of \$150 million aggregate principal amount of senior unsecured notes bearing interest at 8.375% per annum, payable semi-annually on April 21 and October 21 of each year and maturing on October 21, 2020 (the "**2020 Notes**"). Under the terms of the governing note indenture, at any time on or after October 21, 2016, the Corporation was entitled to redeem the 2020 Notes, in whole or in part, at the following redemption prices plus accrued and unpaid interest on the 2020 Notes redeemed, to the applicable redemption date, if redeemed during the twelve (12) month period beginning on October 21 of each of the following years: 2016 – 104.188%; 2017 – 102.792%; 2018 – 101.396%; and 2019 and thereafter – 100.000%.

Effective March 23, 2017, following completion of the issuance of the 2024 Notes described below, the Corporation redeemed the 2020 Notes at a redemption price of \$1,041.88 for each \$1,000 of principal amount redeemed, plus accrued and unpaid interest to, but not including, the redemption date.

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

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

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

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

## Credit Facility

The Corporation has a credit facility with a syndicate of lenders which, as at the date hereof, provides for a \$210 million extendible revolving line of credit and a \$25 million operating line of credit (collectively, the "**Credit Facility**"). The Credit Facility revolves for a 364 day period and is subject to its next 364 day extension by June 6, 2018. If not extended, the Credit Facility will cease to revolve, the margins thereunder will increase by 0.50% and all outstanding advances thereunder will become repayable in one year from the current term date. The available

lending limits of the Credit Facility are reviewed semi-annually and are based on the lenders' assessment of the Corporation's reserves and future commodity prices.

## RATINGS

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

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

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

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

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

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



**MARKET FOR SECURITIES****Trading Price and Volume**

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

<b>Period</b>	<b>Price Range</b>		<b>Volume</b>
	<b>(\$)</b>		
	<b>High</b>	<b>Low</b>	
<b>2017</b>			
January	7.67	5.70	18,344,561
February	6.13	5.07	27,386,707
March	5.59	4.33	27,464,552
April	5.27	4.00	31,948,149
May	4.94	3.80	27,526,532
June	4.20	3.40	15,930,554
July	4.48	3.43	8,993,019
August	4.27	3.62	7,714,337
September	4.71	3.77	17,657,914
October	4.39	3.91	25,155,169
November	4.61	3.76	21,088,625
December	5.59	4.33	27,464,552
<b>2018</b>			
January	3.33	2.20	24,683,064
February	2.31	1.50	20,446,037
March (1 – 21)	1.99	1.37	31,793,937

**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.

<b>Date of Issuance</b>	<b>Type of Securities<sup>(1)</sup></b>	<b>Number of Securities</b>	<b>Price Per Security</b>
Mar 6, 2017	Incentive Awards	11,000	N/A
Apr 1, 2017	Incentive Awards	3,250	N/A
Apr 7, 2017	Incentive Awards	2,187,478	N/A
Sep 11, 2017	Incentive Awards	9,200	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.

<b>Name, Age, Province and Country of Residence</b>	<b>Office Held</b>	<b>Date First Elected or Appointed as a Director</b>	<b>Principal Occupation</b>
<b>John A. Brussa</b> <sup>(2)(3)</sup> Alberta, Canada Age: 61	Chairman	September, 2003	Partner and Chairman, Burnet, Duckworth & Palmer LLP (a law firm).
<b>Jeffery E. Errico</b> <sup>(1)(2)(3)(4)</sup> Alberta, Canada Age: 67	Lead Independent Director	September, 2008	Chairman of Insignia Energy Ltd. from 2007 to 2017; prior thereto, President and Chief Executive Officer of Petrofund Energy Trust, a public oil and gas trust, from April 2003 to June 2006.
<b>Dennis L. Nerland, Q.C.</b> <sup>(1)(3)(4)</sup> Alberta, Canada Age: 65	Director	September, 2003	Partner, Shea Nerland Calnan LLP (a law firm).
<b>David G. Smith</b> <sup>(1)(2)(4)</sup> Alberta, Canada Age: 60	Director	January, 2009	President, Chief Executive Officer and Director of Keyera Corp. since January 1, 2015; prior thereto, President and Chief Operating Officer of Keyera Corp. since May, 2011; prior thereto, Executive Vice President, Liquids Business Unit, Keyera Corp. since January 1, 2011 and of Keyera Facilities Income Fund since November 2008; prior thereto, Executive Vice President and Chief Financial Officer, Keyera Facilities Income Fund since February 2006; prior thereto, Senior Vice President and Chief Financial Officer, Keyera Facilities Income Fund.
<b>Dale O. Shwed</b> Alberta, Canada Age: 59	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.
<b>John G. Leach, CPA, CA</b> Alberta, Canada Age: 53	Senior Vice-President and Chief Financial Officer	N/A	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.

Name, Age, Province and Country of Residence	Office Held	Date First Elected or Appointed as a Director	Principal Occupation
<b>James Taylor</b> Alberta, Canada Age: 43	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.
<b>Jamie L. Bowman</b> Alberta, Canada Age: 53	Vice-President, Marketing and Originations	N/A	Vice-President, Marketing and Originations of the Corporation since December, 2017 and 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.
<b>Paul Dever</b> Alberta, Canada Age: 52	Vice-President, Government and Stakeholder Relations	N/A	Vice-President, Government and Stakeholder Relations of the Corporation since January, 2018; prior thereto, Director, Government & Stakeholder Relations of the Corporation since 2014; prior thereto, Manager, Surface Land & Community Relations of the Corporation since 2008; Prior thereto, Surface Landman of the Corporation since August 2005.
<b>Kevin Evers</b> Alberta, Canada Age: 45	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.
<b>Kurtis Fischer</b> Alberta, Canada Age: 50	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.

<b>Name, Age, Province and Country of Residence</b>	<b>Office Held</b>	<b>Date First Elected or Appointed as a Director</b>	<b>Principal Occupation</b>
<b>Mark Miller</b> Alberta, Canada Age: 42	Vice-President, Land and Negotiations	N/A	Vice-President, Land and Negotiations of the Corporation since January, 2018; prior thereto, Land Manager of the Corporation since 2011; prior thereto, Senior Landman of the Corporation since 2007.
<b>Michael D. Sandrelli</b> Alberta, Canada Age: 49	Corporate Secretary	N/A	Partner, Burnet, Duckworth & Palmer LLP (a law firm).

**Notes:**

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

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

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

As at December 31, 2017, the directors and executive officers of Crew, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 6.9 million Common Shares representing approximately 5% of the issued and outstanding Common Shares.

**Cease Trade Orders, Bankruptcies, Penalties or Sanctions*****Cease Trade Orders***

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

***Bankruptcies***

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

insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

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

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

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

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

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

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

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

### ***Penalties or Sanctions***

To Crew's knowledge, other than as disclosed herein, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory

authority or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

**Conflicts of Interest**

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

### AUDIT COMMITTEE INFORMATION

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

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

Name	Independent	Financially Literate	Relevant Education and Experience
David G. Smith	Yes	Yes	Mr. Smith is President, Chief Executive Officer and a Director (previously President and Chief Operating Officer) of Keyera Corp., previously Keyera Facilities Income Fund, a public energy infrastructure company. Prior to that he was Executive Vice President, Liquids Business Unit and prior to that Executive Vice President and Chief Financial Officer and Corporate Secretary of Keyera Facilities Income Fund and its predecessor companies from June 1998 until May, 2011. Previously Mr. Smith was employed with Gulf Canada Resources Limited and Imperial Oil Limited, and he has more than 35 years of experience in the oil and gas industry. Mr. Smith holds a Bachelor of Mathematics degree from the University of Waterloo, a Master of Business Administration degree from Harvard University and the ICD.D designation from the Institute of Corporate Directors.
Dennis L. Nerland, Q.C.	Yes	Yes	Mr. Nerland is a lawyer practicing primarily in the area of tax and estate planning. Mr. Nerland has been a partner of Shea Nerland Calnan LLP since 1990 and was a partner at Burnet, Duckworth & Palmer LLP prior thereto. Mr. Nerland is a member of the Law Society of Alberta, the Canadian Tax Foundation, the Calgary Bar Association, and the Society of Trusts and Estates Practitioners. Mr. Nerland is also a director of a number of public and private companies. Mr. Nerland has completed the Rotman/Haskayne Directors Education Program and achieved the ICD.D designation and has also successfully completed the Rotman Financial Literacy Program.
Jeffery E. Errico	Yes	Yes	Mr. Errico was Chairman of Insignia Energy Ltd. from 2007 to 2017. Prior to that he was the President and CEO of Petrofund Energy Trust from April 2003 to June 2006. He is a professional engineer who received a Bachelor of Science degree in chemical engineering from the University of British Columbia. He has over 30 years of experience in the oil and gas industry, having served as a senior executive in a number of capacities for several oil and gas companies.

### 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 2017 and 2016:

	<b>Aggregate fees billed (\$)</b>	
	2017	2016
Audit fees	224,500	214,500
Audit-related fees	-	25,000
Tax fees	19,450	48,904
All other fees	60,000	-
	<u>303,950</u>	<u>288,404</u>

*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 76 full-time employees, of which 60 are located in the head office along with two contractors and 16 are field employees. Crew intends to add additional professional and administrative staff as the need arises.

### INDUSTRY CONDITIONS

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



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

## **Pricing and Marketing in Canada**

### ***Crude Oil***

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

### ***Natural Gas***

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

### ***Natural Gas Liquids***

The price of condensate and other natural gas liquids such as ethane, butane and propane ("**NGLs**") sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, 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.

## **Exports from Canada**

Crude oil, natural gas and NGLs exports from Canada are subject to the *National Energy Board Act* (Canada) (the "**NEB Act**") and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "**NEB**") is required, which is no longer the case for natural gas and NGLs. For natural gas and NGLs, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. All crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government.

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m<sup>3</sup> per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the federal government.

The Corporation does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline or other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and political factors. The transportation capacity deficit is not likely to be resolved quickly given the significant length of time required to complete major pipeline or other transportation projects once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

### **Transportation Constraints and Market Access**

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

Developing a strong network of transportation infrastructure for crude oil, natural gas and NGLs, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian crude oil and natural gas industry. Improved means of access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, would help to alleviate the pressures of pricing discussed. Several proposals have been announced to increase pipeline capacity out of Western Canada, to reach Eastern Canada, the United States and international markets via export shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects.

### **The North American Free Trade Agreement and Other Trade Agreements**

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Under the terms of NAFTA, Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

In 2017, the United States government announced its intention to renegotiate NAFTA. As a result, Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. If the United States does give notice of its intent to terminate or withdraw from NAFTA, the earliest such termination or withdrawal could occur would be six months after such notice is given. The renegotiations are still underway and the outcome of such negotiations remain unclear, but as the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Corporation's business.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

## Land Tenure

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

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

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba. In each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 30% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

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

## Royalties and Incentives

### *General*

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

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

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

### **Alberta**

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

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

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments, at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

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

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from

freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

### ***British Columbia***

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

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

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

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

### ***Saskatchewan***

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by entities focused on crude oil and natural gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. In addition, a mineral rights tax is charged to mineral rights holders paid on an annual basis at the rate of \$1.50 per acre owned.

In addition to such surcharges and taxes, the Crown royalty payable in respect of crude oil depends on the type and vintage of crude oil, the quantity of crude oil produced in a month, the value of the crude oil produced and specified adjustment factors determined monthly by the provincial government. The ultimate royalty payable ranges from 5% to 20% depending on the classification of the crude oil, and additional marginal royalty rates may apply, between 30% and 45%, where average wellhead prices received are above base prices. This means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The amount payable as a Crown royalty in respect of production of natural gas and NGLs is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date

of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

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

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

### ***Freehold and Other Types of Non-Crown Royalties***

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract.

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

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

## **Regulatory Authorities and Environmental Regulation**

### ***General***

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

### *Federal*

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

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator ("**CER**"). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within the new impact assessment process, such as large-scale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the public and indigenous groups prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on proponents of major projects remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

### *Alberta*

The AER is the single regulator responsible for all resource development in Alberta. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating



the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

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

#### *British Columbia*

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

#### *Saskatchewan*

The Saskatchewan Ministry of the Economy, Petroleum Branch, is the primary regulator of crude oil and natural gas activities in the province. In May 2011, the Government of Saskatchewan passed changes to *The Oil and Gas Conservation Act* (the "**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* (the "**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* (the "**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, the Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

### **Liability Management Rating Program**

#### *Alberta*

The AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* (the "**OGCA**") establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a

licensee or working interest participant ("**WIP**") becomes insolvent or is unable to meet its obligations. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and where a security deposit is deemed to be required, the failure to post any required amounts may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis on its public website.

In *Redwater Energy Corporation (Re)* ("**Redwater**"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA, including the AB LLR Program, and the *Bankruptcy and Insolvency Act* (the "**BIA**"). This ruling meant that receivers and trustees have the right to renounce assets within insolvency proceedings, which was affirmed by a majority of the Alberta Court of Appeal. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any financial resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. This decision is currently under appeal to the Supreme Court of Canada, with final resolution expected in 2018.

In response to Redwater, the AER issued several bulletins and interim rule changes to govern while the case is appealed and to allow the Government of Alberta to develop appropriate regulatory measures to adequately address environmental liabilities. The AER's *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licence eligibility to operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all are assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer, or to otherwise prove that it can satisfy its abandonment and reclamation obligations. The AER may make further rule changes in response to Redwater at any time, especially as the case heads towards a final determination, which means that additional obligations and/or different requirements may be forthcoming.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19% of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

#### *British Columbia*

The Commission oversees a similar Liability Management Rating Program (the "**BC LMR Program**"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The

LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework. The Commission has announced that it is working to determine how best to manage risks in light of the Redwater decision, so changes may be forthcoming.

### *Saskatchewan*

The Ministry of the Economy administers the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR of below 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Ministry announced that it considers all licence transfer applications non-routine as the Ministry does not strictly rely on the standard LMR calculation in evaluating deposit requirements, and that further changes may be forthcoming.

### ***Climate Change Regulation***

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

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

### *Federal*

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of February 1, 2018, 174 of the 197 parties to the convention have ratified the Paris Agreement.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at \$10/tonne, increasing annually until it reaches \$50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Four provinces currently have carbon pricing systems in place that would meet federal requirements (Alberta, British Columbia, Ontario and Quebec). The federal government will accept comments on the draft legislative proposals to implement the federal carbon pricing system until February 12, 2018.

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the crude oil and natural gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes, by introducing new control measures. Among other things, the proposed regulations limit how much methane

upstream oil and gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

### *Alberta*

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from \$20 to \$30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed \$1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

### *British Columbia*

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93% of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at \$30/tonne. However, in its September update to the 2017/2018 Budget, the Government signalled raising the carbon tax to \$35/tonne in April 2018.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the "**GGIRCA**") came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards

for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

#### *Saskatchewan*

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA, partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation.

#### **Accountability and Transparency**

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "**ESTMA**") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD\$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

#### **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.**

#### **Exploration, Development and Production Risks**

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

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

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as 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 and effective maintenance operations 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, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural 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 all the risks typically associated with such operations, 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 in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, the Corporation could incur significant costs.

#### **Weakness in the Oil and Gas Industry**

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

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("OPEC"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada, uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict the Corporation's cash flow resulting in less funds from operations being available to fund the Corporation's capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. In addition to possibly resulting in a decrease in the value of the Corporation's economically recoverable reserves, lower commodity prices may also result in a decrease in the value of the Corporation's infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of the Corporation's oil and gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms.

## Prices, Markets and Marketing

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

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. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and 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 may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC and other oil and gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. 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.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas production, development and exploration activities. 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.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil 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 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.

## Capital Markets

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

The trading price of 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, or current perceptions of the oil and gas market. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the common shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition,

liquidity and other internal factors. Accordingly, the price at which the common shares of the Corporation will trade cannot be accurately predicted.

### **Political Uncertainty**

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

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the 2016 presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. The administration has announced withdrawal of the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces US corporate tax rates. This may affect competitiveness of other jurisdictions, including Canada. The North American Free Trade Agreement is currently under renegotiation and the result is uncertain at this time. The administration has also taken action with respect to reduction of regulation which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of its common shares.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and gas industry including the balance between economic development and environmental policy.

### **Project Risks**

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

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays 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 and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the 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;
- the effects of inclement weather;
- the availability of drilling and related equipment;



- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all and may be unable to market the oil and natural gas that it produces effectively.

### **Gathering and Processing Facilities, Pipeline Systems and Rail**

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

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. Announcements and actions taken by the governments of British Columbia and Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

Following major accidents in Lac-Mégantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of \$1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

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 materially adverse effect on the Corporation's ability to process its production and deliver the same for sale. Midstream and pipeline companies may take actions to

maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

### **Competition**

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

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the exploration, development, production and marketing of oil 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 and natural gas, but also carry on refining operations and market oil 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 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 enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. 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. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. 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***

Full 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 devices 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. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows by decreasing the Corporation's profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

## Regulatory

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

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact the Corporation's operations, which may affect the Corporation's profitability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*".

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

## Royalty Regimes

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

There can be no assurance that the governments in the jurisdictions in which the Corporation has assets will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions - Royalties and Incentives*".

## Hydraulic Fracturing

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

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

## Disposal of Fluids Used in Operations

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

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

## Environmental

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

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and 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.

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

## Carbon Pricing Risk

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

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Corporation's operating expenses, each of which may have a material adverse effect on the Corporation's profitability and financial condition. Further, the imposition of carbon taxes puts the Corporation at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

## **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 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 assets 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 state of the market 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.

## **Operational Dependence**

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

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

## **Liability Management**

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

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. These programs involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance obligations. In addition, the liability management regime may prevent or interfere with the Corporation's ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability

management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)*, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program and until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

## **Climate Change**

### ***Compliance with greenhouse gas emissions regulations may result in increased operational costs to the Corporation***

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with greenhouse gas ("GHG") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of \$30 per tonne. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Corporation's operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in the Corporation's profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

## **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 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.

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

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

### **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, acquire and develop reserves***

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

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

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 current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

### **Additional Funding Requirements**

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

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

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil 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.

### **Credit Facility Arrangements**

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

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others. As the Corporation's credit facilities are a demand facilities, the lenders may demand repayment by the Corporation at any time.

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

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

### **Issuance of Debt**

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

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



impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

## **Hedging**

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

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil 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 and natural gas prices.

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

## **Availability of Drilling Equipment and Access**

### ***Restrictions on the availability of and access to drilling equipment may impede the Corporation's exploration and development activities***

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to the Corporation and may delay exploration and development activities.

## **Diluent Supply**

### ***A decrease or restriction to diluents supply may increase the Corporation's operating costs***

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

## **Title to Assets**

### ***Defects in the title to the Corporation's properties may result in a financial loss***

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a

title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

### **Reserves Estimates**

***The Corporation's estimated proved and proved plus probable 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 quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves 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 the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil 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 and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. 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 and natural gas, curtailments or increases in consumption by oil 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 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, blow outs, leaks of sour natural 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.

## Geopolitical Risks

***Global political events may adversely affect commodity prices which in turn affect the Corporation's cash flow***

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

## Eco-Terrorism Risks

***The Corporation's properties may be subject to terrorist attack***

The Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

## 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***

Any environmental damage, loss of life, injury or damage to property caused by the Corporation's operations could damage the Corporation's reputation in the areas in which the Corporation operates. Negative sentiment towards the Corporation could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for the Corporation to operate its business and in residents in the areas where the Corporation is doing business opposing further operations in the area by the Corporation. If the Corporation develops a reputation of having an unsafe work site it may impact the ability of the Corporation to attract and retain the necessary skilled employees and consultant to operate its business. Further, the Corporation's reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which the Corporation has no control. In addition, environmental damage, loss of life, injury or damage to property caused by the Corporation's operations 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 common shares.

## **Changing Investor Sentiment**

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

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and 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, 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 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 common shares.

## **Dilution**

### ***The Corporation may issue additional Common Shares, diluting current Shareholders***

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

## **Management of Growth**

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

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

## **Expiration of Licenses and Leases**

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

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

the need for funds to finance ongoing operations and other considerations, as the Board of Directors of the Corporation 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, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation, and as a result, 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.

### **Aboriginal Claims**

***Aboriginal claims may affect the Corporation***

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

### **Breach of Confidentiality**

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

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. 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.

### **Seasonality and Extreme Weather Conditions**

***Oil and natural gas operations are subject to seasonal and extreme 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. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of the Corporation's production if not otherwise tied-in. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

### **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 and of 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 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 Key Personnel**

### ***Loss of key personnel would negatively impact the Corporation's operations***

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key personnel insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the 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. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

## **Information Technology Systems and Cyber-Security**

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

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

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our 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 applies technical and process controls in line with industry-accepted standards to protect our 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. 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 and 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, may acquire different energy related assets and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

## **Waterflood**

### ***Regulatory water use restrictions and/or limited access to water or other fluids may impact the Corporation's production volumes from its waterflood***

The Corporation undertakes or intends to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Corporation needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that the Corporation will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Corporation is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reservoirs. In addition, the Corporation may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Corporation's results of operations.

## **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, 2017, 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, 2017, 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

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

## MATERIAL CONTRACTS

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

## INTERESTS OF EXPERTS

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

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

## ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at [www.sedar.com](http://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 19, 2016. 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](http://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](http://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 22<sup>nd</sup> day of March, 2018.

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

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

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

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

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

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

1. We have evaluated the Corporation's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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, 2017, 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:

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes) (10% discount Rate)			
			Audited (MM\$)	Evaluated (MM\$)	Reviewed (MM\$)	Total (MM\$)
Sroule Associates Limited	31-Dec-17	Canada	nil	2,494	Nil	2,494

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, 2017)".
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:

Sroule Associates Limited  
 Calgary, Alberta, Canada  
 February 5, 2018

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

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

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

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

**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 advise 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.