ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2015

March 24, 2016

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ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
Mmbbl	million barrels
bbl/d	barrels per day
BOPD	barrels of oil per day
NGLs or ngls	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^3	cubic metres
Mboe	1,000 barrels of oil equivalent
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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

Where any disclosure of reserves data is made in this annual information form that does not reflect all reserves of Crew, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

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

FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. In addition there are forward-looking statements in this Annual Information Form under the heading: "Statement of Reserves Data and Other Oil and Gas Information" as to our reserves and future net revenues from our reserves, pricing and inflation rates and future development costs, as to the development of our proved undeveloped reserves and probable undeveloped reserves, as to our future development activities, 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. We believe 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 effect Crew's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or on Crew's website (www.crewenergy.com). Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward looking statements. These forward looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

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

CERTAIN DEFINITIONS

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

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

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook 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;

"EBITDA" is a non-GAAP measure and is defined in the Credit Facility as earnings before interest, taxes, depreciation and amortization, unrealized gains or losses on financial instruments, share-based compensation, all other non-cash items and EBITDA from disposed properties and acquisitions for the most recent twelve month period. Other non-cash items include impairment, gains or losses on divestitures, the premium on flow-through shares and unrealized gains or losses on marketable securities for the most recent twelve month period;

"**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;

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

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

"**Sproule Report**" means the report of Sproule dated February 19, 2016 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2015;

"**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; and

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

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, 2015.

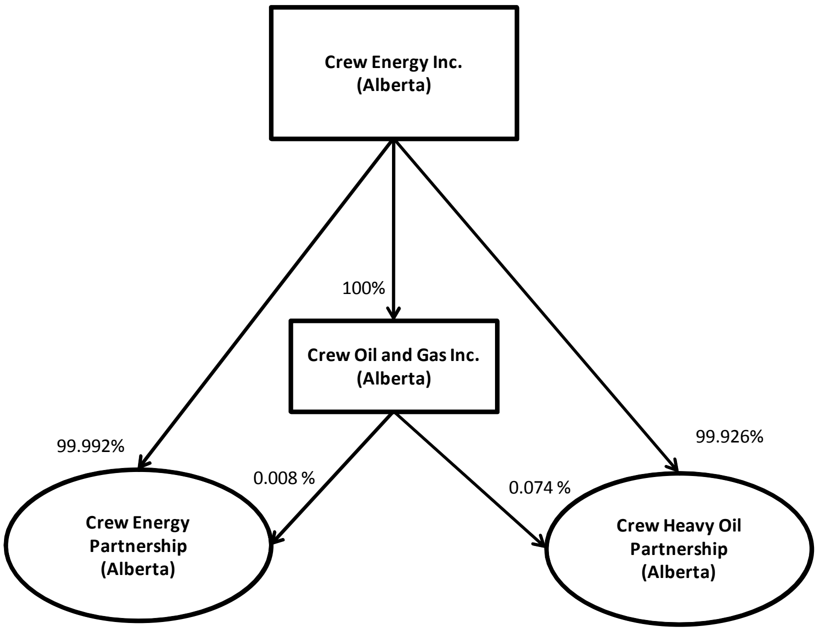
All dollar amounts herein are in Canadian dollars, unless otherwise stated.

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, 2015.



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 long range planning process with its board of directors assessing performance and setting future direction;
- 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 carefully monitors its capital structure with a focus on maintaining a strong financial position in order to finance future growth. This is achieved with regular adjustments to capital spending, hedging of future revenue and costs, the issuance of new equity, issuance of new debt or repayment of existing debt with the proceeds of 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 owning or controlling a significant portion of its infrastructure, including pipelines and oil and gas facilities in its main 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 near term plans include re-investment of cash flows into 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.

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 (the "**Notes**") 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) as at the date of entering into of 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 an innovative 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 mmboe 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.

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 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 have declined significantly in 2015 with continued volatility into early 2016. 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 19, 2016. The effective date of the Statement is December 31, 2015 and the preparation date of the Statement was March 21, 2016. 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, 2015 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 we believe 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, 2015

	RESERVES SUMMARY									
	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		NATURAL GAS LIQUIDS		CONVENTIONAL NATURAL GAS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mboe)	Net (Mboe)
PROVED										
Developed Producing	448.4	396.6	2,164.5	1,958.6	6,393.4	5,364.0	194,438	161,605	41,412.7	34,653.4
Developed Non-Producing	2.3	1.6	1,827.9	1,528.4	202.8	183.1	6,467	5,994	3,111.0	2,712.0
Undeveloped	1,372.8	1,098.3	1,670.7	1,454.5	14,088.3	11,839.3	357,690	294,017	76,746.8	63,394.9
TOTAL PROVED	1,823.6	1,496.4	5,663.2	4,941.6	20,684.6	17,386.4	558,596	461,615	121,270.5	100,760.2
TOTAL PROBABLE	7,761.1	6,554.0	5,047.1	4,036.0	22,518.0	18,372.9	624,195	506,196	139,358.8	113,328.9
TOTAL PROVED PLUS PROBABLE	9,584.7	8,050.4	10,710.2	8,977.6	43,202.6	35,759.3	1,182,791	967,811	260,629.3	214,089.1

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
PROVED										
Developed Producing	683,543	501,754	393,860	324,536	276,787	683,543	501,754	393,860	324,536	276,787
Developed Non-Producing	63,112	50,205	41,207	34,617	29,598	63,112	50,205	41,207	34,617	29,598
Undeveloped	1,346,744	710,567	410,027	250,266	157,223	1,036,554	562,858	331,691	205,374	129,978
TOTAL PROVED	2,093,399	1,262,526	845,094	609,419	463,608	1,783,210	1,114,817	766,758	564,526	436,364
TOTAL PROBABLE	3,083,959	1,446,271	811,703	505,072	335,058	2,276,038	1,061,212	589,738	362,914	237,999
TOTAL PROVED PLUS PROBABLE	5,177,358	2,708,797	1,656,797	1,114,490	798,667	4,059,247	2,176,029	1,356,496	927,441	674,362

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2015

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES[(2)] (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS[(1)] (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	4,656,354	630,820	1,279,460	590,846	61,830	2,093,399	310,189	1,783,210
Total Proved Plus Probable	10,994,103	1,594,492	2,807,750	1,316,124	98,379	5,177,358	1,118,111	4,059,247

Notes:

(1) Reflects estimated abandonment and reclamation costs for all wells that have been attributed reserves. 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, 2015

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES[3] (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAXES[4] (discounted at 10%/year) (Units as noted)
Proved Producing	Light Crude Oil and Medium Crude Oil[1]	8,520	9.83 per boe
	Heavy Crude Oil[1]	31,676	16.07 per boe
	Conventional Natural Gas[2]	353,665	1.85 per mcfe
Total Proved	Light Crude Oil and Medium Crude Oil[1]	8,520	9.83 per boe
	Heavy Crude Oil[1]	77,257	15.56 per boe
	Conventional Natural Gas[2]	759,317	1.33 per mcfe
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil[1]	70,287	6.58 per boe
	Heavy Crude Oil[1]	157,349	17.45 per boe
	Conventional Natural Gas[2]	1,429,161	1.23 per mcfe

Notes:

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

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

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

Reserves Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions which are generally accepted as reasonable.

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

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

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

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

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

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

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling 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, 2015, 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, 2015, 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, 2015
FORECAST PRICES AND COSTS

	OIL			ALBERTA NGLS			NATURAL GAS				
Year	WTI Cushing @ Oklahoma ($US/bbl)	LIGHT, SWEET OIL @ Edmonton (40 °API, 0.3% S) ($Cdn/bbl)	Western Canada Select (WCS) 20.5 °API ($Cdn/bbl)	EDMONTON PROPANE ($Cdn/bbl)	EDMONTON BUTANE ($Cdn/bbl)	EDMONTON PENTANES PLUS ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MmBtu)	NATURAL GAS Westcoast Station 2 Spot Gas Price ($Cdn/MmBtu)	CAPITAL INFLATION RATE %/Year	OPERATING INFLATION RATE(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast											
2016	45.00	55.20	45.26	9.09	39.09	59.10	2.25	1.45	1.5	0.0	0.750
2017	60.00	69.00	57.96	13.64	51.43	73.88	2.95	2.55	1.5	0.0	0.800
2018	70.00	78.43	65.88	25.84	58.46	83.98	3.42	3.02	1.5	1.5	0.830
2019	80.00	89.41	75.11	35.35	66.64	95.73	3.91	3.51	1.5	1.5	0.850
2020	81.20	91.71	77.03	42.30	68.35	98.19	4.20	3.80	1.5	1.5	0.850
2021	82.42	93.08	78.19	42.94	69.38	99.66	4.28	3.88	1.5	1.5	0.850
2022	83.65	94.48	79.36	43.58	70.42	101.16	4.35	3.95	1.5	1.5	0.850
2023	84.91	95.90	80.55	44.24	71.48	102.68	4.43	4.03	1.5	1.5	0.850
2024	86.18	97.34	81.76	44.90	72.55	104.22	4.51	4.11	1.5	1.5	0.850
2025	87.48	98.80	82.99	45.57	73.64	105.78	4.59	4.19	1.5	1.5	0.850
Thereafter	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/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, 2015, were $2.37/mcf for conventional natural gas, $53.10/bbl for light/medium crude oil, $40.40/bbl for heavy crude oil at Lloydminster and $30.28/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 RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

FACTORS	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	HEAVY CRUDE OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	NATURAL GAS LIQUIDS Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2014	3,169.2	2,828.5	5,997.7	6,860.8	5,681.9	12,542.7	16,240.5	17,221.9	33,462.5
Extensions and Improved Recovery(2)	0.0	0.0	0.0	328.3	716.4	1,044.7	4,879.3	5,285.1	10,164.4
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	55.3	35.7	91.0
Technical Revisions(3)	231.2	3,595.3	3,826.5	805.7	(889.6)	(83.9)	1,058.0	(525.4)	532.6
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions(4)	0.0	0.0	0.0	(393.2)	(609.6)	(1,002.9)	0.0	0.0	0.0
Economic Factors	(1,416.1)	1,337.4	(78.7)	(538.8)	148.0	(390.9)	(628.5)	500.6	(127.9)
Production	(160.8)	0.0	(160.8)	(1,399.6)	0.0	(1,399.6)	(920.0)	0.0	(920.0)
December 31, 2015	1,823.6	7,761.1	9,584.7	5,663.2	5,047.1	10,710.2	20,684.6	22,518.0	43,202.6

FACTORS	CONVENTIONAL NATURAL GAS Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)	OIL EQUIVALENT Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2014	481,639	528,955	1,010,594	106,543.7	113,891.6	220,435.2
Extensions and Improved Recovery(2)	98,838	123,615	222,452	21,680.5	26,603.9	48,284.4
Discoveries	1,778	1,153	2,931	351.7	227.9	579.5
Technical Revisions(3)	19,126	(39,701)	(20,575)	5,282.5	(4,436.5)	846.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions(4)	(9)	(14)	(23)	(394.8)	(611.9)	(1,006.7)
Economic Factors	(17,052)	10,187	(6,865)	(5,425.5)	3,683.9	(1,741.6)
Production	(25,723)	0.0	(25,723)	(6,767.6)	0.0	(6,767.6)
December 31, 2015	558,596	624,195	1,182,791	121,270.5	139,358.8	260,629.3

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 and Improved Recovery are the result of step-out locations drilled by Crew. Reserves additions for infill drilling, extensions and improved recovery are combined and reported as "Extensions and Improved Recovery".

(3) Negative Technical Revisions are the result of offsetting well performance at our Attachie and Groundbirch properties affecting undeveloped location type curves.

(4) Dispositions reflect reserves disposed of by Crew pursuant to the Lloydminster Disposition which closed September 30, 2015. See "*Corporate History*".

(5) 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 5 of this AIF.

Proved Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (Mmcf)		NGLs (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2013	48.0	873.5	1,532.9	6,692.5	129,356	288,583	3,793.8	11,789.6
2014	2,440.4	2,638.4	1,111.6	1,752.9	133,217	325,508	5,956.5	11,747.2
2015	0.0	1,372.8	189.9	1,670.7	25,113	357,690	1,083.6	14,088.3

Probable Undeveloped Reserves

Year	Light Crude Oil and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas (Mmcf)		NGLs (Mbbl)	
	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2013	90.9	689.2	1,944.5	9,196.5	118,371	264,039	3,780.6	11,225.6
2014	2,417.5	2,525.2	1,096.3	3,121.8	300,946	472,860	10,078.2	15,687.7
2015	0.0	7,574.3	144.9	2,862.8	191,130	556,571	8,536.3	20,299.7

Sophisticated 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. Crew has areas where multiple zones have been assigned reserves in a well. Once the producing zones are depleted, capital may be spent re-completing the well in another zone. Some of these expenditures are planned to occur in 2016 and beyond, the timing dictated by the predicted reserve life for the currently producing zones. The pace of development of the proved and probable undeveloped reserves (both in 2016 and 2017 as well as in years beyond 2017) 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.

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.

We have 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 $98.4 million for total proved plus probable reserves (approximately $12.0 million, discounted at 10%) at December 31, 2015. In the 2015 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:

Abandonment and Reclamation Costs	**Undiscounted ($M)**
Existing wells with developed reserves and associated facilities	40,547
Future wells with undeveloped reserves and associated facilities	57,832
Total abandonment and reclamation costs for developed and undeveloped reserves	98,379

In addition to the above, the Corporation has estimated undiscounted total abandonment and reclamation costs of $36.9 million related to existing properties 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 1,088 gross (854.5 net) existing wells.

Crew has not established a reclamation fund to pay future asset retirement obligation costs. Crew expects to incur approximately $9.4 million ($8.1 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.

	Forecast Prices and Costs	
Year	**Proved Reserves (MM$)**	**Proved Plus Probable Reserves (MM$)**
2016	49.0	54.7
2017	76.3	122.9
2018	156.8	263.3
2019	25.5	246.3
2020	64.8	185.2
Thereafter	218.4	443.7
Total Undiscounted	590.8	1,316.1

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. We do 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 we 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 main operations are divided into two distinct geographic areas: Montney zone oil and liquids rich natural gas in northeast British Columbia and heavy oil in the Lloydminster area. The northeast British Columbia geographic area is made up of five areas: Septimus, West Septimus, Goundbirch/Monias, Attachie and Tower. Crew has currently budgeted net capital expenditures of $70 million for 2016 predominantly focused on the development of liquids rich natural gas from the Montney formation at Septimus and West Septimus in northeast British Columbia. The program is designed to maintain production levels to meet current transportation commitments, to provide a platform for long-term profitable corporate growth and to further delineate Crew's northeast British Columbia Montney resource.

The following is a description of Crew's principal properties, plants, facilities and installations as at December 31, 2015. Production stated is production before deduction of royalties and includes royalty interests to Crew and, unless otherwise stated, is average production for 2015. 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, 2015 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, 2015.

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 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. At December 31, 2015, Crew had an interest in 65 (61.3 net) producing natural gas wells in the area. In 2015, production averaged 7,594 Boe/d weighted 83% to natural gas. Crew drilled a total of nine (7.3 net) wells in the area in 2015 resulting in nine (7.3 net) gas wells. Production from the Montney is processed through a facility operated by the Corporation and in which Crew currently owns a 28% working interest.

As at December 31, 2015, the Sproule Report assigned total proved plus probable reserves of 16,319 Mbbl of oil and ngls along with 394,839 Mmcf of natural gas to Crew's interests in the Septimus area. At year-end 2015, the Corporation owned 12,051 net acres of land with an average working interest of 92% in this area.

Crew’s 2016 budget plans in the Septimus area include the completion of two (1.3 net) wells.

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. Crew’s production from this area in 2015 averaged 3,620 boe/d weighted 75% to natural gas. At December 31, 2015 the Corporation had 17 (17.0 net) producing gas wells. The Corporation’s current production is processed through Crew’s operated West Septimus facility owned 28% by the Corporation. Construction on the West Septimus facility was completed in August of 2015 and provides 60 mmcf/day of processing capacity. In 2015, Crew drilled 15 (15.0 net) wells resulting in fifteen (15.0 net) gas wells and completed 18 (18.0 net) wells. In 2015, Crew commenced construction of a wholly owned sales gas pipeline from West Septimus to Crew’s Septimus facility which is expected to be completed in the first quarter of 2016. In 2016, Crew plans to drill six (6.0 net) wells and complete 15 (15.0 net) wells in the area.

As at December 31, 2015, the Sproule Report assigned proved plus probable reserves of 22,060 Mbbl of ngls and 473,380 Mmcf of natural gas to Crew's interests in the West Septimus area. At year-end, the Corporation owned 28,332 net acres of land with an average working interest of 87% in the 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 2015, Crew’s production from the area averaged 1,086 boe/d weighted 53% to oil and natural gas liquids. At December 31, 2015 the Corporation had six (5.3 net) producing oil wells. In 2015, Crew drilled three (3.0 net) wells resulting in two (2.0 net) oil wells and one (1.0 net) stratigraphic test well. 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 sales from a 100% Crew owned and operated oil processing facility.

As at December 31, 2015, the Sproule Report assigned proved plus probable reserves of 6,924 Mbbl of oil and ngls and 33,633 Mmcf of natural gas to Crew's interests in the Tower area. At year-end, the Corporation owned 31,289 net acres of land with an average working interest of 85% in the area.

In 2016, the Corporation’s current plans are to focus on cost optimization and will look to accelerate oil and condensate development when commodity prices and project economics warrant.

Groundbirch/Monias, British Columbia

The Groundbirch/Monias area is located 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 2015, the Corporation’s production from this area averaged 1,760 boe/d weighted 99% to natural gas. At December 31, 2015 the Corporation had 10 (8.5 net) producing gas wells.

Currently, all of the Corporation's production in the Groundbirch/Monias area is processed through third party facilities.

As at December 31, 2015, the Sproule Report assigned proved plus probable reserves of 2,904 Mbbl of oil and ngls and 166,825 Mmcf of natural gas to Crew's interests in the Groundbirch/Monias area. At year-end, the Corporation owned 130,349 net acres of land with an average working interest of 78% 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, 2015 the Corporation had no producing gas wells or oil wells.

As at December 31, 2015, the Sproule Report assigned proved plus probable reserves of 4,303 Mbbl of oil and ngls and 106,581 Mmcf of natural gas to Crew's interests in the Attachie area. At year-end, the Corporation owned 28,328 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 production from these reservoirs. At December 31, 2015 the Corporation owned 152 (131.9 net) producing oil wells, two (1.4 net) producing gas wells and 13 (12.6 net) service wells, along with a 100% owned oil battery and numerous single and multi-well batteries located at individual pad sites. In 2015, Crew drilled six (6.0 net) wells in the area resulting in six (6.0 net) oil wells. Production for 2015 averaged 3,883 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 Manitou Pipeline System.

As at December 31, 2015, the Sproule Report assigned proved plus probable reserves of 10,710 mbbl of oil and ngls and 426 mmcf of natural gas to Crew's interests in the Lloydminster area. At year-end 2015, the Corporation owned 84,640 net acres of land with an average working interest of 93% in the area.

In 2016, Crew plans to maintain activity levels on our effective recompletion and workover program and has chosen to defer new drilling until commodity prices recover sufficiently to provide more attractive rates of return.

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 600 boe/d of production in 2015. As at December 31, 2015 the Corporation owned four (1.2 net) producing oil wells and 36 (14.0 net) producing gas wells. As at December 31, 2015, the Sproule Report assigned proved plus probable reserves of 276 mbbl of oil and ngls and 7,107 mmcf of natural gas to Crew's interests in these minor properties.

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, 2015.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	54	54.0	95	94.4	-	-	11	9.4
British Columbia	10	6.5	7	4.8	128	100.8	232	127.4
Saskatchewan	98	77.9	334	294.1	2	1.4	10	8.5
Total	162	138.4	436	393.3	130	102.2	253	145.3

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, 2015.

	Developed Acres		**Undeveloped Acres**	
	Gross	**Net**	**Gross**	**Net**
Alberta	9,638	7,880	17,926	14,743
British Columbia	149,624	74,271	418,832	330,796
Saskatchewan	18,451	15,021	53,742	52,699
Other Canada	-	-	376,920	41,235
Total	177,713	97,172	867,420	439,473

Of the Corporation's undeveloped land, the rights to explore develop and exploit 33,060 net acres may expire by December 31, 2016 if the Corporation takes no action to retain the land. Crew plans to submit applications to continue selected portions of this acreage. We currently have no material work commitments on our undeveloped lands in 2016.

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, 2015, Crew does not have any material commitments to buy or sell natural gas or crude oil production.

As at December 31, 2015, the Corporation held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded
Oil	500 bbl/day	January 1, 2016 – June 30, 2016	US$ WCS - WTI diff	$(14.95)	Swap
Oil	500 bbl/day	January 1, 2016 - December 31, 2016	CDN$ WTI	$116.50	Call
Oil	250 bbl/day	January 1, 2016 - December 31, 2016	CDN$ WTI	$78.25	Swap
Gas	20,000 gj/day	January 1, 2016 - December 31, 2016	AECO C Monthly Index	$2.60	Swap
Gas	2,500 gj/day	April 1, 2016 - October 31, 2016	AECO C Monthly Index	$2.14	Swap
Gas	20,000 mmbtu/day	January 1, 2016 - December 31, 2016	CDN$ Chicago Citygate	$3.79	Swap
Gas	5,000 mmbtu/day	January 1, 2016 – December 31, 2016	Nymex Henry Hub - AECO C ($US/mmbtu)	NYMEX minus US$ - 0.5025/mmbtu	Basis Swap(1)
Gas	2,500 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.73	Swap
Gas	5,000 gj/day	January 1, 2017 - December 31, 2017	AECO C Monthly Index	$2.90	Call Swaption(2)
Total					

Notes:

(1) Crew receives NYMEX Henry Hub "Last Day" Settlement minus applicable spread; Crew pays AECO C(US$/mmbtu)
(2) The referenced contract is a European call swaption, which the counterparty will accept or decline by December 22, 2016.

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2015. 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 2016 and does not anticipate being in a cash income tax payable situation through 2017 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, 2015:

	($ thousands)
Property acquisition costs	
Proved properties	1,114
Unproved properties	3,034
Exploration costs	15,590
Development costs	227,794
Corporate acquisitions	-
Property dispositions	(86,555)
Total	160,977

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, 2015.

	Gross			Net		
	Exploration	**Development**	**Total**	**Exploration**	**Development**	**Total**
Crude Oil	-	8	8	-	8.0	8.0
Natural Gas	-	24	24	-	22.4	22.4
Dry[(1)]	-	-	-	-	-	-
Service[(2)]	-	-	-	-	-	-
Stratigraphic Test	-	1	1	-	1.0	1.0
Total:	-	33	33	-	31.4	31.4

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 2016, the Corporation intends to continue to focus on the development of its northeast British Columbia Montney assets including liquids rich natural gas at Septimus and West Septimus. The Corporation is currently budgeting for a net $70 million capital expenditure program in 2016, which is planned to be financed through cash flow from operations and, if required, the Corporation's bank facility. It is currently the Corporation’s intention to monitor commodity prices and their impact on 2016 cash flow and, if necessary, adjust capital expenditures to approximate cash flow.

For details on Crew's important current and likely exploration and development activities during 2016, 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, 2016 as estimated in the Sproule Report which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light Crude Oil and Medium Crude Oil		Heavy Crude Oil		Natural Gas Liquids		Conventional Natural Gas		Total Oil Equivalent	
Reserves Category	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (Mcf/d)**	**Net (Mcf/d)**	**Gross (Boe/d)**	**Net (Boe/d)**
Total Proved										
Septimus	61	49	0	0	1,410	1,209	45,194	41,721	9,003	8,212
West Septimus	0	0	0	0	1,648	1,523	35,067	32,757	7,493	6,982
Other	211	182	2,633	2,316	157	132	11,237	9,959	4,874	4,290
Total Proved Plus Probable										
Septimus	60	48	0	0	1,463	1,256	46,911	43,322	9,342	8,524
West Septimus	0	0	0	0	1,884	1,742	40,084	37,445	8,565	7,983
Other	225	193	3,016	2,591	173	146	12,152	10,766	5,439	4,724

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 2016 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			
	2015			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[1]				
Light Crude Oil and Medium Crude Oil (bbl/d)	340	336	435	657
Heavy Crude Oil (bbl/d)	2,849	3,741	4,035	4,735
Conventional Natural Gas (Mcf/d)	84,479	62,778	65,062	69,498
NGLs (bbl/d)	3,437	2,233	2,342	2,060
Combined (BOE/d)	20,706	16,773	17,656	19,035
Average Price Received				
Light Crude Oil and Medium Crude Oil (bbl/d)	48.75	51.29	63.64	49.28
Heavy Crude Oil (bbl/d)	31.92	38.49	52.60	36.63
Conventional Natural Gas ($/Mcf) [2]	2.04	2.37	2.56	2.62
NGLs ($/bbl)	27.87	30.62	36.21	27.17
Combined ($/BOE) [2]	18.13	22.54	27.81	23.31
Transportation Expenses				
Light Crude Oil and Medium Crude Oil (bbl/d)	1.28	1.88	1.01	4.58
Heavy Crude Oil (bbl/d)	0.95	0.98	1.05	1.05
Conventional Natural Gas ($/Mcf)	0.35	0.38	0.33	0.18
NGLs ($/bbl)	2.19	1.73	2.13	2.71
Combined ($/BOE)	1.96	1.91	1.78	1.96
Royalties Paid				
Light Crude Oil and Medium Crude Oil (bbl/d)	8.23	8.81	10.28	0.86
Heavy Crude Oil (bbl/d)	3.69	5.22	6.88	3.79
Conventional Natural Gas ($/Mcf)	0.04	0.16	0.08	0.34
NGLs ($/bbl)	2.59	2.84	3.88	3.48
Combined ($/BOE)	1.23	2.32	2.65	2.00
Operating Expenses				
Light Crude Oil and Medium Crude Oil (bbl/d)	20.58	23.02	33.76	25.17
Heavy Crude Oil (bbl/d)	15.95	15.29	16.76	17.29
Conventional Natural Gas ($/Mcf)	0.85	1.05	0.95	0.95
NGLs ($/bbl)	5.34	4.97	4.89	5.92
Combined ($/BOE)	6.89	8.47	8.81	9.28
Netback Received[3]				
Light Crude Oil and Medium Crude Oil (bbl/d)	18.66	17.58	18.59	18.67
Heavy Crude Oil (bbl/d)	11.33	17.00	27.91	14.50
Conventional Natural Gas ($/Mcf)	0.80	0.78	1.20	1.15
NGLs ($/bbl)	17.75	21.08	25.31	15.06
Combined ($/BOE)	8.05	9.84	14.57	10.07

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, 2015:

	Light Crude Oil and Medium Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLS (bbl/d)	Oil Equivalent (BOE/d)
Lloydminster Alberta	-	1,585	121	-	1,605
Total Alberta	-	1,585	121	-	1,605
Septimus	-	-	37,852	1,285	7,594
West Septimus	-	-	16,304	903	3,620
Other	441	-	16,029	333	3,446
Total British Columbia	441	-	70,185	2,521	14,660
Lloydminster Saskatchewan	-	2,249	168	-	2,277
Total Saskatchewan	-	2,249	168	-	2,277
Total	441	3,834	70,474	2,521	18,542

For the year ended December 31, 2015, approximately 60% of Crew's gross revenue was derived from crude oil and natural gas liquids production and 40% 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 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 which bear interest at 8.375% per annum, payable semi-annually on April 21 and October 21 of each year and maturing on October 21, 2020. At any time prior to October 21, 2016, the Corporation may redeem the Notes, in whole or in part, at a price equal to 100% of the principal amount of the 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 October 21, 2016, redeem up to 35% of the aggregate principal amount of the Notes with the net cash proceeds from certain equity offerings at a redemption price of 108.375%, plus accrued and unpaid interest to the applicable redemption date. At any time on or after October 21, 2016, the Corporation may redeem the Notes, in whole or in part, at the following redemption prices plus accrued and unpaid interest on the 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%.

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

The 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 Notes and senior in right of payment to all future indebtedness of the Corporation that is expressly subordinated to the Notes. The Notes are guaranteed, jointly and severally, on a senior unsecured basis by the Corporation's material subsidiaries. The 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 Notes, the 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 $220 million extendible revolving line of credit and a $30 million operating line of credit (collectively, the "**Credit Facility**"). The Credit Facility revolves for a 364 day period and is subject to its next 364 day extension by June 6, 2016. 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. As a result of the issuance of the Notes as described above, the credit agreement requires the Corporation to maintain a debt to EBITDA ratio of 4:1 and a secured debt to EBITDA ratio of 3:1 at the end of each fiscal quarter. At December 31, 2015, these ratios were 2.3:1 and 0.8:1, respectively.

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 negative 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 Notes have been assigned credit ratings of B by DBRS with a negative 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 provisional credit rating of B on the 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 provisional credit rating of B- on the 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.

Period	Price Range ($) High	Low	Volume (in 000s)
2015			
January	6.34	4.73	19,367,734
February	6.48	5.13	30,199,687
March	5.85	4.74	18,424,548
April	5.71	4.66	23,004,560
May	6.20	5.07	23,414,207
June	6.05	5.45	12,868,758
July	5.92	4.36	17,346,009
August	5.09	3.40	14,833,619
September	5.01	3.95	12,438,936
October	5.90	4.15	22,117,987
November	4.98	3.87	12,794,031
December	4.84	3.29	15,883,861
2016			
January	4.29	2.65	17,557,946
February	3.85	2.84	19,671,073
March (1-23)	4.23	3.13	17,606,574

Prior Sales of Unlisted Securities

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

Date of Issuance	Type of Securities(1)	Number of Securities	Price Per Security
April 14, 2015	Incentive awards	1,770,696	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 directors and officers of the Corporation, as applicable, are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name, Age, Province and Country of Residence	Office Held	Date First Elected or Appointed as a Director	Principal Occupation
John A. Brussa(2)(3) Alberta, Canada Age: 59	Chairman	September, 2003	Partner and Vice-Chairman, Burnet, Duckworth & Palmer LLP (a law firm).
Jeffery E. Errico(1)(2)(3)(4) Alberta, Canada Age: 65	Lead Independent Director	September, 2008	Chairman of Insignia Energy Ltd., formerly a public, now private energy company, since 2007; prior thereto, President and Chief Executive Officer of Petrofund Energy Trust, a public oil and gas trust, from April, 2003 to June 2006.
Dennis L. Nerland, Q.C.(1)(3)(4) Alberta, Canada Age: 63	Director	September, 2003	Partner, Shea Nerland Calnan LLP (a law firm).
David G. Smith(1)(2)(4) Alberta, Canada Age: 58	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.
Dale O. Shwed Alberta, Canada Age: 57	President, Chief Executive Officer and Director	June, 2003	President and Chief Executive Officer of the Corporation since June, 2003; prior thereto, President and Chief Executive Officer of Baytex.
John G. Leach, CA Alberta, Canada Age: 51	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
Ken Truscott Alberta, Canada Age: 57	Senior Vice-President, Business Development and Land	N/A	Senior Vice-President, Business Development and Land of the Corporation since January, 2009; prior thereto, Vice-President, Land of the Corporation since September, 2007; prior thereto, Independent businessman since May, 2006; prior thereto, President and Chief Executive Officer of Morpheus Energy Corporation.
Rob Morgan Alberta, Canada Age: 51	Senior Vice-President and Chief Operating Officer	N/A	Senior Vice-President and Chief Operating Officer of the Corporation since July, 2011; prior thereto, Chief Operating Officer – Upstream of Harvest Operations Corp., a wholly-owned subsidiary of Harvest Energy Trust since February, 2006; prior thereto, Vice-President Operations and Corporate Development Viking Energy Royalty Trust since 2004; prior thereto, Vice-President Corporate Development, Petrovera Resources since 1999.
Shawn A. Van Spankeren Alberta, Canada Age: 43	Vice-President, Finance and Administration	N/A	Vice-President, Finance and Administration of the Corporation since October 1, 2013; prior thereto, Vice-President Finance and Controller of the Corporation since January, 2009; prior thereto, Controller of the Corporation since September, 2003; prior thereto, Controller of Baytex.
Kurtis Fischer Alberta, Canada Age: 48	Vice-President, Business Development	N/A	Vice-President, Business Development since November, 2012; prior thereto, Vice-President, Production since July, 2011; prior thereto, Vice-President, Acquisitions and Divestitures 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.
Jamie L. Bowman Alberta, Canada Age: 51	Vice-President, Marketing	N/A	Vice-President, Marketing of the Corporation 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.
Michael D. Sandrelli Alberta, Canada Age: 47	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, 2015, the directors and executive officers of Crew, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 5.8 million Common Shares representing approximately 4.1% 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. Dennis Nerland, a director of the Corporation, 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. John Brussa, Chairman of the Board of the Corporation, was formerly a director of Calmena Energy Services Inc. ("**Calmena**") (a public oilfield service company) which was placed in receivership on January 20, 2015. Mr. Brussa resigned as a director of Calmena on June 30, 2014. Mr. Brussa was formerly a director of Enseco Energy Services Corp. ("**Enseco**"), which was placed in receivership on October 14, 2015. Mr. Brussa resigned as a director of Enseco in connection with the appointment of the receiver on October 14, 2015.

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 D.

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 30 years of experience in the oil and gas industry. Mr. Smith holds a Bachelor of Mathematics degree from the University of Waterloo and a Master of Business Administration degree from Harvard University.
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 is the Chairman of Insignia Energy Ltd., formerly a public, now private energy company. Prior to that he was the President and CEO of Petrofund Corp. 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 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 2015 and 2014:

	Aggregate fees billed	
	2015	2014
Audit fees	205,900	235,500
Audit-related fees	45,000	-
Tax fees	31,605	47,715
All other fees	-	-
	282,505	283,215

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, as well as offering memorandum review.

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 79 full-time employees, of which 62 are located in the head office and 17 are field employees, along with three part-time consultants. Crew intends to add additional professional and administrative staff as the need arises.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

In Canada, the producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licenses. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the *National Energy Board Act* (Canada).

Natural Gas

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. 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 Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 40 years) or for a larger quantity requires an exporter to obtain an export license from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain 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 the party maintaining the restriction 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.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings**.** NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, 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, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands 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 product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

The federal government has signaled it will, *inter alia*, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing more stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change within 90 days of the 2015 Paris Climate Conference which concluded on December 12, 2015. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the current Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently estimated to be 20 bbl/d for oil and 200 mcf/d for gas, the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016.

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the method and figures by which the royalties are calculated will be released to the public. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% - 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% - 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework" until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production 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. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

While the MRF eliminates the various royalty credits and incentives, outlined above, for wells drilled after December 31, 2016, the Government of Alberta has committed to creating cost allowance programs for both enhanced oil recovery schemes and higher risk experimental drilling. Details of these programs are scheduled to be released simultaneously with the finalization of the MRF, prior to March 31, 2016.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well, and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It 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 freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

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, including the following:

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3 year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m^3. Horizontal wells that are spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

Saskatchewan

In Saskatchewan, taxes ("**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For 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. The Resource Surcharge applies to resource trusts in addition to resource corporations.

The amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production 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, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas. The current regulatory scheme provides for certain differences with respect to the administration of "fourth tier gas" which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on EOR projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards apply to existing licensed wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 11 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia, and Saskatchewan 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 license. The Government of British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007 to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses issued after January 1, 2009 at the conclusion of the primary term of the lease or license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we 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 with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. 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 such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The Alberta Energy Regulator (the "**AER**") is the single regulator responsible for all energy development in Alberta. The AER ensures 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 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. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method to natural resource management sets out to engage and consult with stakeholders and the public. While the AER is the primary regulator for energy development, several governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the AER, the Alberta Environmental Monitoring, Evaluation and Reporting Agency, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and 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 oil and 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 an oil and 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 licenses, 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 licenses and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, the Government of Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**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* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**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 aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA 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 defunct. 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 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 liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

The AER 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 5 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 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.

British Columbia

In British Columbia, the Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the 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 will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements 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 to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October

2013, the federal government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

On December 12, 2015, the UNFCCC adopted the Paris Agreement, to which Canada is a participant. The Paris Agreement mandates that all countries must work together to limit global temperature rise resulting from GHG emissions to a goal of less than 2° Celsius and to pursue efforts to limit below 1.5° Celsius, through implementing successive nationally determined contributions. Technical details remain unreleased, but the Government of Canada is expected to announce a plan within 90 days of the Paris Agreement, which will significantly increase Canada's GHG emission reduction targets.

Alberta

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year ("**Regulated Emitters**"), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. In 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

Regulated Emitters can meet their emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund are made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan which proposes to introduce a carbon tax on all emitters. An economy-wide levy $30 per tonne of GHG emissions will be phased in, starting in January 2017 at $20 per tonne, and increasing to $30 per tonne in January 2018. An oil sands specific approach was proposed to replace the $30 per tonne of GHG emissions to further reduce emissions and promote carbon competitiveness rather than rewarding past intensity levels. A 100 megatonne per year limit for GHG emissions was proposed for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. The existing SGER will be replaced for large industrial facilities with a Carbon Competitiveness Regulation ("**CCR**"), in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Alberta is 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

In February 2008, the Government of British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of GHG emissions. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, the Government of British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

In the 2012 Budget, the Government of British Columbia announced that it would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review, the Government of British Columbia confirmed that it will keep its revenue-neutral carbon tax; the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

On April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Alberta government, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable the Government of British Columbia to implement a cap and trade system are currently under development. Crew is in compliance with its reporting obligations under the current legislative regime.

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 received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. Although the MRGGA and related regulations have yet to be proclaimed in force, draft versions indicate that the Government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

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

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 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 participations 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 assure 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, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other 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

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 China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels 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 the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional 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 especially if certain reserves become uneconomic. In addition, lower commodity prices have affected, and are anticipated to continue to affect, the Corporation's cash flow resulting in a reduced capital expenditure budget. As a result, 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. 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 dilutive terms.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space 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 as well as 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 conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, 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. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, among other factors. 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 acquisition, 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, OPEC actions, 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.

See "*Weakness in the Oil and Gas Industry*".

Market Price of Common Shares

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. Similarly, the market price of the common shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the common shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The 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 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, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

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 recourse 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. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Project Risks

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 over-runs 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 and hydraulic fracturing, 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

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own and 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, and in particular the processing facilities, 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 produce and market oil and natural gas production. In addition, the pro-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. Furthermore, 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 in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows. The federal government has signaled that it plans to review the National Energy Board approval process for large projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Megantic, 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, 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 add additional costs to the transportation of crude oil by rail.

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.

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the 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. 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, methods, and reliability of delivery and storage.

Cost of New Technologies

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. 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, 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

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. 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.

Regulatory

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. See "*Industry 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. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. 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 to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces 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 will take effect on January 1, 2017. Details of this new regime are scheduled to be finalized and released before March 31, 2016. See "*Industry Conditions - Royalties and Incentives*".

Hydraulic Fracturing

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.

Environmental

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 certain 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 laws 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.

Liability Management

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 becomes defunct. These programs generally 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 required. Changes of the ratio of the Corporation's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. In addition, the liability management system 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. See "*Industry Conditions - Liability Management Rating Programs*".

Climate Change

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 participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets are not binding. 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. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, to which Canada was a participant, the Government of Canada is expected to announce a plan to further reduce its GHG emission reduction targets by March 11, 2016. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. 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 not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions - Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

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 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'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 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.

Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in the Corporation's revenues from its reserves, which may 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

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 amalgamations, mergers, take-over bids or disposition of assets, among others.

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. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. 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 amounts outstanding under the Corporation's Credit Facility.

There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Continued depressed commodity prices or further reductions in commodity prices could result in a further reduction to 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 Facility 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 Facility, 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 its Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. 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

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 ;
- 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 and Completion Equipment and Access

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

Diluent Supply

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

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 an unforeseen 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.

Reserve Estimates

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 are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were 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

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

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 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.

In addition, 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.

Dilution

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 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 Licences and Leases

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 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

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, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of 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.

Aboriginal Claims

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.

Breach of Confidentiality

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 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

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

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. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation.

Third Party Credit Risk

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

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 of 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

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 person 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.

Expansion into New Activities

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.

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 risk 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, 2015, 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, 2015, 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. 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.

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

Crew Energy Inc.
Suite 800, 250 - 5th Street S.W.
Calgary, Alberta
T2P 0R4
Tel: (403) 266-2088
Fax: (403) 266-6259
www.crewenergy.com

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

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

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

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

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

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

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

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

DATED as of this 24th day of March, 2016.

(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, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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, 2015, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's management and Board of Directors:

			Net Present Value of Future Net Revenue (before income taxes (10% discount Rate)			
Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (County)	Audited (MM$)	Evaluated (MM$)	Reviewed (MM$)	Total (MM$)
Sproule Associates Limited	December 31, 2015	Canada	Nil	1,656.8	Nil	1,656.8

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, 2015)".

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

EXECUTED as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada
February 19, 2016

(signed) "*Jason E. Robottom*"
Jason E. Robottom, P.Eng.
Supervisor, Engineering and Partner

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

(signed) "*Cameron P. Six*"
Cameron P. Six, P.Eng.
Vice-President Engineering, Chief Engineer and Director

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.