ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2016

March 30, 2017

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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 InPlay, 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 InPlay, capital expenditures and other matters; the continued availability of capital, acquisitions of reserves, undeveloped lands and skilled personnel; the continuation of the current tax and regulatory regime and other assumptions contained in this Annual Information Form.

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

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect InPlay'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 InPlay's website (www.InPlayoil.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);

"**Acquisitionco**" means 1992122 Alberta Ltd., a corporation incorporated under the ABCA and previously a wholly-owned subsidiary of Anderson;

"**Anderson**" means Anderson Energy Inc. as it existed prior to completion of the Arrangement;

"**Anderson Shares**" means common shares of Anderson;

"**Arrangement**" means the plan of arrangement under the provisions of Section 193 of the ABCA which was completed on November 7, 2016 and which resulted in the business combination of Private InPlay and Anderson to form InPlay;

"**Arrangement Acquisition Assets**" means certain petroleum and natural gas properties, interests and related assets acquired by Private InPlay in conjunction with the Arrangement pursuant to the Asset Acquisition Agreement;

"**Asset Acquisition**" means the acquisition by Private InPlay of the Arrangement Acquisition Assets pursuant to the Asset Acquisition Agreement;

"**Asset Acquisition Agreement**" means the purchase and sale agreement between Private InPlay and an arm's length third party vendor pursuant to which Private InPlay acquired the Arrangement Acquisition Assets in conjunction with completion of the Arrangement;

"**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;

"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.

"**InPlay**" or the "**Corporation**" means InPlay Oil Corp., a corporation amalgamated pursuant to the ABCA under the Arrangement, and includes its predecessors where the context so requires;

"**InPlay Shares**" or "**Common Shares**" means common shares of InPlay;

"**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;

"**Private InPlay**" means InPlay Oil Corp. as it existed prior to completion of the Arrangement;

"**Private InPlay Shares**" means common shares of Private InPlay which were exchanged for InPlay Shares pursuant to the Arrangement on the basis of 0.1303 of an InPlay Share for each one (1) Private InPlay Share held;

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

"**Sproule Report**" means the report of Sproule dated March 23, 2017 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2016;

"**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;

"**Transactions**" means, collectively, the Arrangement and the Asset Acquisition; 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, 2016.

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

NOTE ON SHARE REFERENCES

The Private InPlay Shares were exchanged for InPlay Shares pursuant to the Arrangement on the basis of 0.1303 of an InPlay Share for each one (1) Private InPlay Share held. References in this Annual Information Form to Private InPlay Shares are on a pre-Arrangement basis while references to InPlay Shares are on a post-Arrangement basis. Readers should multiply any referenced number of Private InPlay Shares by 0.1303 to arrive at the equivalent number of InPlay Shares. Readers should divide the issuance price of any Private InPlay Shares or the exercise price of any options to acquire Private InPlay Shares by 0.1303 to arrive at the equivalent issuance price or exercise price for the InPlay Shares, as the case may be.

CORPORATE STRUCTURE

General

Private InPlay was originally incorporated under the ABCA as 1712226 Alberta Ltd. on November 12, 2012. On November 21, 2012 Private InPlay filed Articles of Amendment to change its name to "InPlay Oil Corp.". On July 10, 2013 Private InPlay filed Articles of Amendment to remove its "private company" restrictions. On November 7, 2016, Private InPlay completed a reverse take-over transaction of Anderson under the Arrangement and pursuant to which Private InPlay and Acquisitionco were amalgamated under the ABCA ("**Amalco1**"), immediately following which Amalco1 and Anderson were amalgamated under the ABCA to form the current issuer under the name "InPlay Oil Corp.".

Intercorporate Relationships

InPlay does not have any subsidiaries.

InPlay's head office is located at Suite 920, 640 – 5th Avenue S.W., Calgary, Alberta T2P 3G4 and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

The InPlay Shares trade on the TSX under the symbol "IPO".

DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS

Business Plan and Growth Strategies

InPlay has been engaged in the business of exploring for, developing and producing oil and natural gas, and acquiring oil and natural gas properties in western Canada since it commenced operations in June 2013. Since commencing operations, InPlay has concentrated on exploration and development drilling of prospects in the province of Alberta, focusing in the Pembina area of central Alberta. InPlay's operations are currently directed towards light oil prospects in its Pembina and Rocky Mountain House areas.

The business plan of InPlay has been to generate profitable growth, in production, reserves and funds flow from operations. To accomplish this, InPlay has focused on building a large, low decline, light oil focused asset base. InPlay targets areas in prospects that it believes could result in meaningful reserve and production additions.

The following are integral components of InPlay's corporate strategy:

- InPlay focuses on identifying, acquiring and exploiting large hydrocarbon reservoirs by applying proven and evolving technologies;
- InPlay creates and maintains a significant inventory of drilling locations that allows the Corporation to allocate capital on a risked rate of return basis;
- InPlay actively manages its portfolio of assets to take advantage of value enhancing acquisitions when market conditions permit;
- InPlay 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 and the use of bank credit facilities and issuance of new equity to fund growth as determined appropriate;
- InPlay promotes safe and environmentally responsible operations; and
- InPlay values and maintains an entrepreneurial culture to attract and retain high quality staff.

To achieve sustainable and profitable growth, management of InPlay 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, InPlay strives to maximize its working interest ownership in its properties where reasonably possible. In reviewing potential drilling or acquisition opportunities, InPlay 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 InPlay; and (iv) InPlay's technical expertise in the opportunity. InPlay also employs a strategy of reducing operating risk and costs by owning or participating in strategic infrastructure as opportunities present themselves. While InPlay 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, InPlay 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. InPlay's near term plans include re-investment of cash flows into growing the Corporation's production with a focus on development of its light oil assets in central Alberta while maintaining a strong financial position. 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.

InPlay 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 bank credit facilities.

InPlay 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 in the development of the Corporation's business since it commenced active operations in June 2013.

In February 2014, Private InPlay completed its initial private equity backed financing pursuant to which it issued 25 million Private InPlay Shares on a private placement basis at a price of $1.25 per share for gross proceeds of approximately $31.25 million. In March 2014, Private InPlay completed a brokered private placement financing of an additional 15,672,933 Private InPlay Shares at a price of $1.25 per share for gross proceeds of approximately $19.6 million.

In the first quarter of 2014, Private InPlay completed two acquisitions of producing oil and gas properties in the Hanna area of central Alberta for aggregate cash consideration of approximately $7.7 million.

In the second quarter of 2014, Private InPlay completed an acquisition of producing oil and gas properties in the Pembina area of Alberta for cash consideration of approximately $45.6 million. Private InPlay also completed minor acquisitions of complementary assets in the second half of 2014.

In June 2014, Private InPlay completed a series of non-brokered private placements of an aggregate of 35,107,000 Private InPlay Shares for aggregate gross proceeds of approximately $43.9 million.

In September 2014, Private InPlay completed the acquisition (the "**Kingsmere Acquisition**") of Kingsmere Resources Ltd. ("**Kingsmere**"), a private oil and gas company with complementary oil and gas assets in and around InPlay's core Pembina area. At the time of closing of the Kingsmere Acquisition, the principal properties of Kingsmere were producing approximately 950 boe/d, comprised of approximately 90% light oil and NGLs and including approximately 11,415 net acres of undeveloped land. Consideration for the Kingsmere Acquisition was comprised of approximately $62.2 million in cash and the assumption of approximately $23 million in debt and working capital. Following the Kingsmere Acquisition, Kingsmere was amalgamated with Private InPlay to form "InPlay Oil Corp." A minor complimentary property acquisition was also completed in the third quarter of 2014 pursuant to which oil and gas production properties were acquired in the Pembina area for consideration comprised of approximately $260,000 in cash and $140,000 Private InPlay Shares at a deemed value of $1.25 per share. In the fourth quarter of 2014, Private InPlay completed a further minor acquisition in producing oil and gas properties, as well as a facility, in the Pembina area for cash consideration of approximately $4 million.

In conjunction with completion of the Kingsmere Acquisition, Private InPlay entered into a $60 million senior secured credit facility with a major chartered Canadian bank (the "**Private InPlay Credit Facility**").

In December 2014, Private InPlay completed brokered and non-brokered private placements of an aggregate of 13,474,731 Private InPlay Shares at a price of $1.65 per share for gross proceeds of approximately $22.2 million.

Throughout 2014, Private InPlay drilled a total of 14 gross (12.8 net) wells comprised of 2.0 gross (2.0 net) vertical wells and 3.0 (3.0 net) horizontal wells in the Hanna area, 2.0 gross (2.0 net) Cardium wells in the Pembina area and 6.0 gross (5.5 net) Belly River wells in the Pigeon Lake area and 1.0 (0.3 net) non-core area horizontal well.

In the first quarter of 2015, Private InPlay completed a further minor acquisition of producing oil and gas properties in the Pembina area for consideration of approximately $85,000 in cash and the issuance of 484,848 Private InPlay Shares at a deemed value of $1.65 per share.

In 2015, despite a challenging commodity price environment throughout the year, Private InPlay successfully drilled, completed and placed on production 7 Cardium horizontal wells in the Pembina area. Private InPlay entered into several price protective commodity hedges in 2015 and continued to maximize operational activities and to reduce operating and administrative costs. Following the completion of the annual renewal of the Private InPlay Credit Facility in October 2015, Private InPlay maintained the Private InPlay Credit Facility at $60 million and added an additional $15 million development facility.

In the first half of 2016, Private InPlay continued development drilling, completion and tie-in of 2.0 gross (1.73 net) Belly River horizontal wells.

On September 19, 2016, Private InPlay entered into an arrangement agreement with Anderson pursuant to which Private InPlay would complete a reverse takeover business combination transaction with Anderson by way of a plan of arrangement under the provisions of Section 193 of the ABCA to form a new corporation that would continue to carry on the business and operations previously carried on by Private InPlay and Anderson, respectively, under the name "InPlay Oil Corp.". In conjunction with completion of the Arrangement, Private InPlay completed the acquisition of the Arrangement Acquisition Assets for total consideration of $46.1 million comprised of 16.7 million Private InPlay Shares having a deemed value of $4.3 million and $41.8 million in cash consideration. Positive working capital of $0.7 million was assumed on closing resulting in total consideration of $45.5 million for the Asset Acquisition. The Transactions were completed on November 7, 2016. The InPlay Shares commenced trading in substitution for the Anderson Shares on the TSX under the new trading symbol "IPO" on November 10, 2016.

In conjunction with completion of the Arrangement, Private InPlay completed a non-brokered private placement of Common Shares for proceeds of $0.4 million and a bought deal brokered private placement of common share subscription receipts (the " **Private InPlay Subscription Receipts**") of Private InPlay for gross proceeds of approximately $69.9 million (the "**Arrangement Financing**").

Under the terms of the Arrangement, holders of Private InPlay Shares and holders of Private InPlay Subscription Receipts (collectively, "**Private InPlay Securities**" and each a "**Private InPlay Security**") received, through a series of steps under the Arrangement, 0.1303 of an InPlay Share for each one (1) Private InPlay Security held and each holder of Anderson Shares continued to hold one (1) InPlay Share for each one (1) Anderson Share held.

At the time of closing of the Transactions, the principal properties of Anderson were producing approximately 1,400 boe/d, comprised of approximately 40% light oil and ngls and included approximately 33,540 net acres of undeveloped land, and the Arrangement Acquisition Assets were producing approximately 800 boe/d, comprised of approximately 72% light oil and ngls, of high net back production entirely from the Cardium formation and included approximately 3,640 net acres of undeveloped land .

Upon completion of the Transactions, InPlay also entered into a new $60.0 million senior secured credit facility with a syndicate of financial institutions (the "**InPlay Credit Facility**"). The InPlay Credit Facility consists of a revolving line of credit of $50 million and an operating line of credit of $10 million.

Following completion of the Transactions, during the balance of 2016, InPlay has continued the development of its Pembina property with 4 (3.9 net) Cardium horizontal wells drilled in the fourth quarter. Two (1.9 net) of the Cardium horizontals came on production in late December 2016 while the others began production in mid-February 2017.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. InPlay 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. InPlay's competitors include companies which have greater financial resources, staff and facilities than those of InPlay. 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. InPlay 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. InPlay 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, natural gas liquids and natural gas production. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on, among other things, the Corporation's revenues and financial condition. Commodity prices declined significantly in 2016 with continued volatility into early 2017. 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 InPlay 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 March 23, 2017. The effective date of the Statement is December 31, 2016 and the preparation date of the Statement was March 23, 2017. 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, 2016 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 province of 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, 2016**

	RESERVES SUMMARY							
	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL		NATURAL GAS LIQUIDS		CONVENTIONAL NATURAL GAS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mboe)	Net (Mboe)
PROVED								
Developed Producing	4,074.1	3,624.4	675.3	490.7	15,328	13,990	7,304.0	6,446.7
Developed Non-Producing	481.3	424.5	95.1	82.3	1,303	1,228	793.5	711.4
Undeveloped	5,072.3	4,528.1	748.0	653.3	15,964	14,695	8,481.0	7,630.7
TOTAL PROVED	9,627.7	8,577.0	1,518.3	1,226.2	32,595	29,913	16,578.5	14,788.8
TOTAL PROBABLE	5,172.0	4,428.5	632.3	510.7	12,617	11,440	7,907.2	6,845.9
TOTAL PROVED PLUS PROBABLE	14,799.6	13,005.5	2,150.7	1,736.9	45,212	41,354	24,485.7	21,634.7

	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	159,461	132,453	113,639	99,821	89,260	159,461	132,453	113,639	99,821	89,260
Developed Non-Producing	21,567	16,517	13,395	11,342	9,903	21,567	16,517	13,395	11,342	9,903
Undeveloped	162,255	108,531	74,261	51,495	35,794	162,255	108,531	74,261	51,495	35,794
TOTAL PROVED	343,282	257,500	201,295	162,658	134,957	343,282	257,500	201,295	162,658	134,957
TOTAL PROBABLE	232,996	159,102	116,016	88,857	70,632	173,549	120,898	90,169	70,638	57,357
TOTAL PROVED PLUS PROBABLE	576,278	416,602	317,311	251,516	205,589	516,831	378,398	291,464	233,296	192,314

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2016

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT AND RECLAMATION COSTS[1] (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Total Proved	1,010,621	107,079	398,233	129,064	32,963	343,282	0	343,282
Total Proved Plus Probable	1,555,278	181,501	579,424	178,413	39,662	576,278	59,447	516,831

Note:

(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*".

FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2016

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]	105,697	$19.20 per boe
	Conventional Natural Gas[2]	7,942	$ 1.41 per mcfe
Total Proved	Light Crude Oil and Medium Crude Oil[1]	187,785	$14.47 per boe
	Conventional Natural Gas[2]	13,510	$ 1.24 per mcfe
Total Proved Plus Probable	Light Crude Oil and Medium Crude Oil[1]	298,606	$15.56 per boe
	Conventional Natural Gas[2]	18,705	$ 1.28 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, 2016, 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, 2016, 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, 2016
FORECAST PRICES AND COSTS

	OIL			ALBERTA NGLS			NATURAL GAS				
Year	WTI Cushing @ Oklahoma ($US/bbl)	LIGHT, SWEET OIL @ Edmonton (40 ^{0} API, 0.3% S) ($Cdn/bbl)	Western Canada Select (WCS) 20.5 ^{0} 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											
2017	55.00	65.58	53.12	22.74	47.60	67.95	3.44	3.04	0.0%	0.0%	0.780
2018	65.00	74.51	61.85	28.04	55.49	75.61	3.27	2.87	2.0%	2.0%	0.820
2019	70.00	78.24	64.94	30.64	57.65	78.82	3.22	2.82	2.0%	2.0%	0.850
2020	71.40	80.64	66.93	32.27	58.80	80.47	3.91	3.51	2.0%	2.0%	0.850
2021	72.83	82.25	68.27	33.95	59.98	82.15	4.00	3.60	2.0%	2.0%	0.850
2022	74.28	83.90	69.64	35.68	61.18	83.86	4.10	3.70	2.0%	2.0%	0.850
2023	75.77	85.58	71.03	37.46	62.40	85.61	4.19	3.79	2.0%	2.0%	0.850
2024	77.29	87.29	72.45	39.30	63.65	87.39	4.29	3.89	2.0%	2.0%	0.850
2025	78.83	89.03	73.90	41.19	64.92	89.21	4.40	4.00	2.0%	2.0%	0.850

Escalation Rate of 2.0% thereafter

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, 2016, were $2.53/mcf for conventional natural gas, $49.71/bbl for light/medium crude oil and $23.01/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

	LIGHT CRUDE OIL AND MEDIUM CRUDE OIL			NATURAL GAS LIQUIDS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2015	4,679.0	2,426.6	7,105.6	217.4	120.2	337.6
Extensions and Improved Recovery(2)	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	(444.8)	(209.6)	(654.4)	51.2	7.1	58.3
Acquisitions	6,111.3	2,952.1	9,063.4	1,308.1	504.4	1,812.5
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	(235.3)	2.8	(232.5)	(6.0)	0.7	(5.3)
Production	(482.5)	0.0	(482.5)	(52.4)	0.0	(52.4)
December 31, 2016	9,627.7	5,172.0	14,799.6	1,518.3	632.3	2,150.7

	CONVENTIONAL NATURAL GAS			OIL EQUIVALENT		
FACTORS	Proved (Mmcf)	Probable (Mmcf)	Proved Plus Probable (Mmcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2015	5,283	2,494	7,777	5,776.8	2,962.5	8,739.4
Extensions and Improved Recovery(2)	0.0	0.0	0.0	0.0	0.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	491	(124)	367	(311.9)	(223.4)	(535.3)
Acquisitions	28,088	10,363	38,451	12,100.8	5,183.8	17,284.6
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	(216)	(116)	(331)	(277.3)	(15.8)	(293.0)
Production	(1,051)	0.0	(1,051)	(710.0)	0.0	(710.0)
December 31, 2016	32,595	12,617	45,212	16,578.5	7,907.2	24,485.7

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) Extensions and Improved Recovery includes Infill Drilling.
(3) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

Proved Undeveloped Reserves

Year	Light Crude Oil and Medium 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
2014	2,302.8	2,302.8	3,277	3,277	103.2	103.2
2015	325.7	2,117.5	186	2,241	15.2	106.8
2016	3,348.9	5,072.3	13,569	15,964	631.6	748.0

Probable Undeveloped Reserves

Year	Light Crude Oil and Medium 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
2014	1,726.5	1,726.5	1,620	1,620	70.4	70.4
2015	276.2	1,727.4	176	1,644	14.2	88.1
2016	2,178.4	3,898.1	6,290	7,854	315.0	411.9

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. The pace of development of the proved and probable undeveloped reserves (both in 2017 and 2018 as well as in years beyond 2018) 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.

The Corporation has a significant amount of proved undeveloped and probable undeveloped reserves assigned to its properties. 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 $39.7 million for total proved plus probable reserves (approximately $5.3 million, discounted at 10%) at December 31, 2016. 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	20,560.6
Future wells with undeveloped reserves and associated facilities	19,101.2
Total abandonment and reclamation costs for developed and undeveloped reserves	39,661.8

In addition to the above, the Corporation has estimated undiscounted total abandonment and reclamation costs of $31.0 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. InPlay expects to incur abandonment and reclamation costs on approximately 1,018 gross (687.4 net) existing wells.

InPlay has not established a reclamation fund to pay future asset retirement obligation costs. Although InPlay currently faces no significant mandated or regulatory requirement to incur any abandonment or reclamation costs over the next three years, the Corporation estimates that it could incur approximately $1.2 million ($1.0 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 (M$)**	**Proved Plus Probable Reserves (M$)**
2017	23,925.4	32,733.4
2018	51,517.2	58,386.9
2019	53,621.1	71,373.6
2020	0.0	15,918.9
2021	0.0	0.0
Thereafter	0.0	0.0
Total Undiscounted	129,063.6	178,412.7

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, 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

The following is a description of InPlay's principal properties, plants, facilities and installations as at December 31, 2016. Production stated is InPlay's working interest share before deduction of royalties and before royalty income volumes and, unless otherwise stated, is average production for the year ended December 31, 2016. Reserve amounts are 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, 2016 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 acreage well count information are as at December 31, 2016.

Pigeon Lake, Alberta

InPlay's Pigeon Lake, Alberta property consists of an average working interest of approximately 79% in 18,804 gross (14,879net) acres of mainly Belly River rights in the Knob Hill and Keystone areas. The property includes 78 gross (68.6 net) producing oil wells. Facilities in the area include a battery connected to a sales oil pipeline, other minor batteries, gathering systems, water injection systems and compression. Production from the property is weighted 88% to crude oil and NGLs. Average daily production from the property for the year ended December 31, 2016 was 826 boe/d. As at December 31, 2016, the Sproule Report attributed proved plus probable reserves of 4,361 mbbl of crude oil and NGLs and 2,482 mmcf of natural gas to the property.

Pembina, Alberta

InPlay's Pembina, Alberta property consists of an average working interest of approximately 65% in 51,410 gross (33,340 net) acres of mainly Cardium rights in the Drayton Valley, Buck Creek, Cynthia, Lodgepole and Pendryl areas. The property includes 116 gross (71.0 net) producing oil wells and 2 gross (1.7 net) producing natural gas wells. Facilities in the area include a battery connected to a sales oil pipeline, other minor batteries, gathering systems, water injection systems and compression. Production from the property is weighted 71% to crude oil and NGLs. Average daily production from the property for the year ended December 31, 2016 was 718 boe/d. As at December 31, 2016, the Sproule Report attributed proved plus probable reserves of 8,920 mbbl of crude oil and NGLs and 17,464 mmcf of natural gas to the property. In 2017, InPlay plans to drill 14 (10.0 net) wells and complete 16 (12.0 net) wells in the area.

Rocky Mountain House (Willesden Green), Alberta

InPlay's Willesden Green, Alberta property consists of an average working interest of approximately 75% in 24,312 gross (18,133 net) acres of mainly Cardium rights in the Willesden Green area. The property includes 37 gross (27.5 net) producing oil wells. Facilities in the area include batteries, gathering systems and compression. Production from the property is weighted 55% to crude oil and NGLs. Average daily production from the property for the year ended December 31, 2016 was 124 boe/d. As at December 31, 2016, the Sproule Report attributed proved plus probable reserves of 2,669 mbbl of crude oil and NGLs and 11,244 mmcf of natural gas to the property. In 2017, InPlay plans to drill 2 (2.0 net) wells and complete 2 (2.0 net) wells in the area.

Red Deer, Alberta

InPlay's Red Deer, Alberta property consists of an average working interest of approximately 52% in 124,092 gross (64,497 net) acres of various rights in the Sylvan Lake and Leslieville areas. The property includes 18 gross (9.2 net) producing oil wells and 78 gross (47.4 net) producing natural gas wells. Facilities in the area include a 100% owned sweet gas plant, batteries, gathering systems and compression. Production from the property is weighted 23% to crude oil and NGLs. Average daily production from the property for the year ended December 31, 2016 was 92 boe/d. As at December 31, 2016, the Sproule Report attributed proved plus probable reserves of 668 mbbl of crude oil and NGLs and 13,450 mmcf of natural gas to the property. InPlay has no current plans to drill in the area in 2017.

Minor Areas

InPlay's Minor areas, consist of an average working interest of approximately 75% in 128,261 gross (96,171 net) acres of various different rights outside of our core areas. The property includes 16 gross (13.9 net) producing oil wells and 2 gross (0.2 net) producing natural gas wells. Facilities in the areas include a batteries, gathering systems and compression. Production from the property is weighted 77% to crude oil and NGLs. Average daily production from the property for the year ended December 31, 2016 was 180 boe/d. As at December 31, 2016, the Sproule Report attributed proved plus probable reserves of 332 mbbl of crude oil and NGLs and 572 mmcf of natural gas to the property. InPlay has no current plans to drill in the area in 2017.

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, 2016.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	265	190.2	124	79.4	82	49.3	145	98.3
British Columbia	0	0.0	0	0.0	0	0.0	1	0.8
Total	265	190.2	124	79.4	82	49.3	146	99.1

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, 2016.

	Developed Acres		**Undeveloped Acres**	
	Gross	**Net**	**Gross**	**Net**
Alberta	199,641	139,118	146,598	87,422
British Columbia	640	480	0	0
Total	200,281	139,598	146,598	87,422

Of the Corporation's undeveloped land, the rights to explore develop and exploit 21,568 net acres may expire by December 31, 2017 if the Corporation takes no action to retain the land. InPlay plans to submit applications to continue selected portions of this acreage. We currently have no material work commitments on our undeveloped lands in 2017.

In those situations where InPlay holds interests in different formations under the same surface area pursuant to separate leases, InPlay would consider this to be two separate leases and would calculate them separately. This would arise where InPlay 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, InPlay 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, 2016, InPlay does not have any material commitments to buy or sell natural gas or crude oil production.

As at December 31, 2016, the Corporation held derivative commodity contracts as follows:

Subject of Contract	Notional Quantity	Term	Reference	Strike Price	Option Traded[1]
Natural Gas	1,000/GJ/day	Jan 1, 2017 – Mar 31, 2018	AECO	$3.055/GJ (CDN$)	SWAP
Crude Oil	500 bbls/day	Jan 1 – June 30, 2017	WTI	$53.65/bbl (USD$)	SWAP
Crude Oil	200 bbs/day	Jan 1– Dec 31, 2017	WTI	$55.00/bbl sold call (CDN$) $73.65/bbl sold put (CDN$)	Costless Collar
Crude Oil	200 bbls/day	Jan 1 – Dec 31, 2017	WTI	$55.00/bbl sold call (CDN$) $74.00/bbl sold put (CDN$)	Costless Collar
Crude Oil	200 bbls/day	Jan 1 – Dec 31, 2017	WTI	$47.50/bbl sold call (USD$) $57.80/bbl sold put (USD$)	Costless Collar
Crude Oil	500 bbls/day	Jan 1 – Dec 31, 2017	WTI	$47.00/bbl sold call (USD$) $59.60/bbl sold put (USD$)	Costless Collar

Note:

(1) Costless Collar indicates InPlay concurrently sold put and call options at strike prices such that the costs and premiums received offset each other, thereby completing the derivative contracts on a costless basis.

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2016. 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 respect of the period ended December 31, 2017 and does not anticipate being in a cash income tax payable situation through 2019 at the currently anticipated rate of capital expenditures and forecasted commodity prices.

Costs Incurred

The following table summarizes capital expenditures (net of incentives and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2016:

	($ thousands)
Property acquisition costs[1]	
Proved properties	43,993
Unproved properties	1,457
Exploration costs	-
Development costs	11,083
Corporate acquisition[1]	
Proved properties	27,802
Unproved properties	5,410
Total	89,745

(1) Property and Corporate acquisition costs are equal to the total amount of cash and share consideration net of any working capital balances assumed on closing of the applicable transaction.

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, 2016.

	Gross			Net		
	Exploration	**Development**	**Total**	**Exploration**	**Development**	**Total**
Light and Medium Crude Oil	0	6	6	0.0	5.7	5.7
Conventional Natural Gas	0	0	0	0.0	0.0	0.0
Dry(1)	0	0	0	0.0	0.0	0.0
Service(2)	0	0	0	0.0	0.0	0.0
Stratigraphic Test	0	0	0	0.0	0.0	0.0
Total:	0	6	6	0.0	5.7	5.7

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 2017, the Corporation intends to continue to focus on the development of its core Cardium assets in its Pembina and Rocky Mountain House (Willesden Green) areas. The Corporation is currently budgeting for a $28.0 million capital expenditure program in 2017, which is planned to be financed through cash flow from operations and, if required, the Corporation's bank facility. It is the Corporation's intention to monitor commodity prices and their impact on 2017 cash flow and, if necessary, adjust capital expenditures to approximate cash flow.

For details on InPlay's important current and likely exploration and development activities during 2017, 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, 2017 as estimated in the Sproule Report which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light Crude Oil and Medium Crude Oil		**Natural Gas Liquids**		**Conventional Natural Gas**		**Total Oil Equivalent**	
Reserves Category	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (bbl/d)**	**Net (bbl/d)**	**Gross (Mcf/d)**	**Net (Mcf/d)**	**Gross (Boe/d)**	**Net (Boe/d)**
Total Proved Alberta								
Pigeon Lake	578	503	38	28	399	334	682	586
Pembina	1,516	1,399	208	171	3,759	3,447	2,351	2,144
Rocky	384	323	78	53	1,932	1,775	784	672
Red Deer	28	23	78	56	2,154	2,007	464	414
Minors	120	106	1	1	213	195	157	140
	2,626	2,353	403	309	8,456	7,758	4,438	3,955
Total Proved Plus Probable Alberta								
Pigeon Lake	614	532	41	30	431	361	727	622
Pembina	1,898	1,753	252	211	4,442	4,086	2,891	2,645
Rocky	458	381	87	60	2,167	1,987	907	772
Red Deer	29	24	82	59	2,279	2,120	490	436
Minors	125	110	1	1	222	204	163	145
	3,123	2,799	463	361	9,541	8,758	5,177	4,620

Note:

(1) The Corporation's Pembina area comprises the only individual field that accounts for 20% or more of the Corporation's estimated 2017 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 InPlay's assets for the periods indicated below:

	Quarter Ended			
	2016			
	Mar. 31	**June. 30**	**Sept. 30**	**Dec. 31**
Average Daily Production[1]				
Light Crude Oil and Medium Crude Oil (bbl/d)	1,392	1,268	1,093	1,522
Conventional Natural Gas (Mcf/d)	2,051	2,170	1,654	5,592
NGLs (bbl/d)	129	93	92	258
Combined (BOE/d)	1,863	1,723	1,460	2,712
Average Price Received[2]				
Light Crude Oil and Medium Crude Oil ($/bbl)	37.20	51.16	51.35	58.64
Conventional Natural Gas ($/Mcf)	1.86	1.30	2.24	3.33
NGLs ($/bbl)	13.22	25.61	21.23	27.54
Combined ($/BOE)	30.75	40.67	42.30	42.40
Transportation Expenses				
Light Crude Oil and Medium Crude Oil ($/bbl)	0.22	0.20	0.20	0.22
Conventional Natural Gas ($/Mcf)	0.75	0.68	0.44	0.57
NGLs ($/bbl)	-	-	-	-
Combined ($/BOE)	0.97	0.88	0.64	0.79
Royalties Paid				
Light Crude Oil and Medium Crude Oil ($/bbl)	3.37	4.36	5.06	5.55
Conventional Natural Gas ($/Mcf)[3]	0.01	(0.35)	(0.10)	0.00
NGLs ($/bbl)	2.04	5.41	5.04	6.54
Combined ($/BOE)	2.93	3.21	3.96	3.75
Operating Expenses[4]				
Light Crude Oil and Medium Crude Oil ($/bbl)	11.47	13.40	13.79	9.88
Conventional Natural Gas ($/Mcf)	2.82	3.82	3.48	6.05
NGLs ($/bbl)	1.06	0.99	1.16	1.68
Combined ($/BOE)	15.35	18.20	18.43	17.61
Netback Received[5]				
Light Crude Oil and Medium Crude Oil ($/bbl)	22.14	33.20	32.30	42.99
Conventional Natural Gas ($/Mcf)	(1.72)	(2.85)	(1.58)	(3.29)
NGLs ($/bbl)	10.12	19.21	15.03	19.32
Combined ($/BOE)	11.50	18.38	19.27	20.25

Notes:

(1) Before deduction of royalties and including royalty interests.
(2) Operating costs are comprised of direct costs incurred to operate both oil and gas wells and facilities.
(3) Conventional Natural Gas royalties paid include Crown capital cost, operating cost and custom processing fee credits.
(4) Average price received does not include the impact of the Corporation's realized gains and losses on derivative financial instruments.
(5) 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, 2016:

	Light Crude Oil and Medium Crude Oil (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLS (bbl/d)	Oil Equivalent (BOE/d)
Pigeon Lake	668	596	59	826
Pembina	456	1,263	51	718
Rocky Mountain House	53	333	15	124
Red Deer	4	428	17	92
Minors	137	251	1	180
Total Alberta	1,318	2,871	143	1,940

For the year ended December 31, 2016, approximately 75% of InPlay's gross revenue was derived from crude oil and natural gas liquids production and 25% was derived from natural gas production.

DIVIDEND POLICY

InPlay has never declared or paid any dividends on its outstanding Common Shares. InPlay 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. InPlay 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 InPlay Credit Facility, InPlay 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 and an unlimited number of preferred shares issuable in series. No preferred shares are currently issued and outstanding. The following is a description of the rights, privileges, restrictions and conditions attaching to the 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.

Preferred Shares

Subject to the provisions of the ABCA, the board of directors of InPlay is authorized to fix, before the issue thereof, the designation, rights and privileges, restrictions and conditions attaching to any series of preferred shares.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX and trade under the symbol "IPO". The following sets forth trading information for the Anderson Shares and, following completion of the Arrangement, the InPlay Shares (as reported by the TSX) for the periods indicated.

Period(1)(2)	Price Range ($) High	Low	Volume (in 000s)
2016			
Pre-Consolidation			
January	0.015	0.005	27,023,396
February	0.005	0.005	761,282
March	0.005	0.005	3,349,304
April	0.005	0.005	2,891,902
May	0.005	0.005	1,301,586
June (1 - 19)	0.005	0.005	1,017,816
Post-Consolidation			
June (20 - 30)	3.48	2.02	344,994
July	2.73	2.27	209,010
August	2.43	2.04	350,825
September	2.25	2.02	688,006
October	2.20	1.95	213,963
November	2.05	1.80	1,896,257
December	2.09	1.89	939,817
2017			
January	2.27	1.88	1,916,998
February	2.34	1.94	1,067,602
March (1 – 29)	2.09	1.86	1,054,183

Notes:

(1) Prior to completion of the Arrangement on November 7, 2016, the Common Shares of Anderson Energy Inc. were listed for trading on the TSX under the trading symbol "AND".

(2) Following the completion of the Arrangement, the InPlay Shares commenced trading on the TSX in substitution for the Anderson Shares under the trading symbol "IPO" effective November 10, 2016.

Prior Sales of Unlisted Securities

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

Date of Issuance	Type of Securities	Number of Securities(3)	Price Per Security(3)
November 7, 2016	Private InPlay Shares(1)	16,666,666	$0.30
November 7, 2016	Private InPlay Subscription Receipts(2)	233,230,349	$0.30 - $0.35

Notes:

(1) Reflects the share consideration issued in connection with completion of the Asset Acquisition.
(2) Reflects completion of the Arrangement Financing and includes Private InPlay Shares issued directly to certain insiders in conjunction with completion of the Arrangement Financing. The Private InPlay Subscription Receipts were issued at $0.30 per Private InPlay Subscription Receipt for non-flow-through shares and at $0.32 and $0.35 for Private InPlay Subscription Receipts issued on a CDE and CEE flow-through share basis, respectively.
(3) All of the above noted securities were exchanged for InPlay Shares under the Arrangement on the basis of 0.1303 of an InPlay Share for each one (1) Private InPlay Share or Private InPlay Subscription Receipt held, as the case may be.

There were no issuances of stock options in the year ended December 31, 2016.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

There are no securities of the Corporation currently held in escrow. The following securities are subject to a contractual restriction on transfer.

Designation of Class	Number of Securities that are Subject to a Contractual Restriction on Transfer	Percentage of Class
Common Shares	701,769	1%

Note:

(1) In conjunction with completion of the Arrangement, all of the executive officers of InPlay entered into trading restriction agreements with JOG Capital Corp., in its capacity as advisor to certain private equity shareholders of InPlay (the "**Investor**") pursuant to which such individuals have agreed not to sell, dispose of or otherwise trade Common Shares held by them, subject to such exceptions which may be determined from time to time by the Board of Directors of InPlay. The governing agreements terminate on the earlier of the first date that the Investor holds less than 10% of the issued and outstanding Common Shares, the date that the individual ceases to be an executive officer of InPlay or upon the mutual consent of the individual and the Investor.

DIRECTORS AND OFFICERS

The following table sets forth the names of directors and officers of InPlay, together with their province and country of residence, period served as a director, the number of voting securities of InPlay beneficially owned, or controlled or directed, directly or indirectly by such individuals, the offices held in the Corporation, membership on committees of the Board of Directors and principal occupations for the past five years. The information as to InPlay Shares beneficially owned or controlled or directed is based upon information furnished to InPlay by the individuals as of the date hereof.

Name, Province and State of Country of Residence	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Douglas J. Bartole Alberta, Canada **President, Chief Executive Officer and Chairman of the Board**	51	November, 2012	258,863

President and Chief Executive Officer of the Corporation since November 2012; prior thereto, Mr. Bartole was President and Chief Executive Officer of Vero Energy Inc., a public oil and gas company, from September 2005 to November 2012.

Name, Province and State of Country of Residence	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Donald Cowie Alberta, Canada	63	February, 2014	Nil(4)

Independent Director

Member of:
-Compensation Committee
-Reserves Committee

Founding Partner and President of JOG Capital Inc., a private equity investment management company, since 2002.

	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Craig Golinowski Alberta, Canada	36	May, 2014	Nil(4)

Director

Member of:
-Corporate Governance Committee

Managing Director of JOG Capital Inc., a private equity investment management company, since 2007; prior thereto, Mr. Golinowski was an Investment Banker with RBC Capital Markets from 2002 to 2005.

	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Dennis L. Nerland, Q.C. Alberta, Canada	63	July, 2013	78,180

Independent Director

Member of:
-Audit Committee
-Compensation Committee(1)
-Corporate Governance Committee(1)

Partner, Shea Nerland LLP (a law firm).

	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Stephen C. Nikiforuk Alberta, Canada	47	November, 2013	29,318

Lead Independent Director

Member of:
-Audit Committee(1)
-Compensation Committee

Mr. Nikiforuk has been the President of MyownCFO Professional Corporation since October 2011 and was President of MyownCFO Inc. from July 2009 to June 2012, both private companies. He was the Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011 and the Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly Kereco Energy Ltd.), a public oil and gas company, from January 2005 to March 2008. Mr. Nikiforuk holds both Certified Professional Accountant and Chartered Accountant designations.

Name, Province and State of Country of Residence	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Dale O. Shwed Alberta, Canada	57	July, 2013	78,180

Independent Director

Member of:
-Reserves Committee[1]
-Corporate Governance Committee

President and Chief Executive Officer of Crew Energy Inc., a public oil and gas company, since June, 2003; prior thereto, Mr. Shwed was the President and Chief Executive Officer of Baytex Energy Ltd., a public oil and gas company.

	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Stephen Yuzpe Ontario, Canada	51	October, 2014	Nil[5]

Independent Director

Member of:
-Audit Committee
-Reserves Committee

President and Chief Executive Officer of Sprott Resource Holdings Inc. (formerly Adriana Resources Inc.) since February 2017 and President and Chief Executive Officer of Sprott Resource Corp. (now a wholly-owned subsidiary of Sprott Resource Holdings Inc.) since October 2013; prior thereto, Mr. Yuzpe was the Chief Financial Officer of Sprott Resource Corp. from April 2009 to October 2013.

	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Kevin Yakiwchuk Alberta, Canada	45	N/A	75,574

Vice President Exploration

Vice President Exploration of the Corporation; prior thereto, founder and VP Exploration at Vero Energy Inc.; prior thereto, VP Exploration at True Energy; prior thereto, Geologist at Crestar Energy, Renaissance Energy and Shell Canada.

	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Gordon Reese Alberta, Canada	59	N/A	133,379

Vice President Business Development

Vice President Business Development of the Corporation; prior thereto, founder, President and CEO of Invicta Energy Corp.; prior thereto, President and CEO at Cipher Energy Inc., VP Exploration at True Energy and various prospect generation and management and geological roles at CS Resources and Gulf Canada.

Name, Province and State of Country of Residence	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Thane Jensen Alberta, Canada	51	N/A	110,321

Vice President Operations

Vice President Operations of the Corporation; prior thereto, Sr. V.P. Operations, Exploration and Development, and prior thereto, VP Engineering at Penn West Exploration Ltd.; prior thereto Reservoir Engineer, Exploitation Engineer, and Drilling and Completions Engineer at PanCanadian Petroleum Ltd.

	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Darren Dittmer Alberta, Canada	47	N/A	123,633

Chief Financial Officer

Chief Financial Officer of the Corporation; prior thereto, CFO of Barrick Energy Inc. from September 2008 until sale of all assets in July 2013; prior thereto, Controller and CFO of Cadence Energy; and prior thereto, Controller of Kereco Energy, Ketch Resources and Upton Resources. Mr. Dittmer holds both Certified Management Accountant and Chartered Professional Accountant designations.

	Age	Director Since	Common Shares Beneficially Owned, Controlled or Directed, Directly or Indirectly
Michael Sandrelli Alberta, Canada	48	N/A	26,545

Corporate Secretary

Partner with Burnet Duckworth & Palmer LLP.

Notes:

(1) Chairman of Committee.
(2) The Corporation does not have an Executive Committee.
(3) All of the directors will hold office until the next annual meeting of shareholders or until their successor is duly elected or appointed, unless their office is earlier vacated.
(4) Messrs. Cowie and Golinowski do not currently own, or exercise direction and control over, any InPlay Shares. Such individuals are principals of JOG Capital Inc., a private equity investment management company which manages each of JOG Limited Partnership No. VI and JOG VI B Limited Partnership, which collectively own an aggregate of 20,946,489 InPlay Shares.
(5) Mr. Yuzpe does not currently own, or exercise direction and control over, any InPlay Shares. Mr. Yuzpe is a director and senior officer of Sprott Resource Holdings Inc. (formerly Adriana Resources Inc.) a publicly listed private equity company that is transitioning into a diversified natural resource holdings company. Sprott Resource Holdings Inc. owns 7,096,619 InPlay Shares..

All of the directors and officers of InPlay 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, 2016, the directors and executive officers of InPlay, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 906,992 million Common Shares representing approximately 1.5 % of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To InPlay'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 InPlay'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) ("**CCAA**"). 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, at which time Mr. Nerland resigned from Alston's board of directors.

On April 2, 2015, CYGAM Energy Inc., a junior oil and gas company of which Mr. Nikiforuk was a director, filed a voluntary assignment in bankruptcy under the Bankruptcy and Insolvency Act (Canada) and the directors, including Mr. Nikiforuk, resigned concurrent therewith.

Penalties or Sanctions

To InPlay'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 InPlay will be subject to in connection with the operations of InPlay. In particular, certain of the directors and officers of InPlay 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 InPlay or with entities which may, from time to time, provide financing to, or make equity investments in, InPlay’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 InPlay are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract.

AUDIT COMMITTEE INFORMATION

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

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

Name	Independent	Financially Literate	Relevant Education and Experience
Steve Nikiforuk	Yes	Yes	Mr. Nikiforuk holds a B.B.A. with an accounting major from St. Francis Xavier University. Mr. Nikiforuk is an active Chartered Professional Accountant, CA and in 2013 completed the Directors Education Program developed by the Institute of Corporate Directors and holds their ICD.D designation. In June 2016, Mr. Nikiforuk also obtained the Family Enterprise Advisor designation. Mr. Nikiforuk served as the Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly Kereco Energy Ltd.), a public oil and gas company, from January 2005 to March 2008. Mr. Nikiforuk is also a director of CanAir Nitrogen Inc., a private company that supplies the oil and gas industry in Alberta and British Columbia with cryogenic liquid nitrogen, and Whitecap Resources Inc., a public light oil production and development company, and serves as Audit Committee Chair for Whitecap Resources Inc. Mr. Nikiforuk is also on the board of a charitable foundation.
Steve Yuzpe	Yes	Yes	Mr. Yuzpe holds a Bachelor of Science, Engineering (Mechanical) degree from Queen's University along with the Professional Engineering designation (P.Eng.) and a Masters in Business Administration from the Richard Ivey School of Business in London, Ontario. Mr. Yuzpe is a CFA charterholder and has over 15 years of executive and financial management experience with public and private corporations. Over his career, Mr. Yuzpe has developed specific expertise in financings, restructurings, financial and internal reporting, strategic development and business planning, corporate governance, investor relations, regulatory compliance and treasury management. Mr. Yuzpe is the President and Chief Executive Officer of Sprott Resource Holdings Inc. (formerly Adriana Resources Inc.) a public company, a position he has held since February 2017 and is the President and Chief Executive Officer of Sprott Resource Corp. (now a wholly-owned subsidiary of Sprott Resource Holdings Inc.). Prior thereto, Mr. Yuzpe served as the Chief Financial Officer of Sprott Resource Corp. from April 2009 to October 2013.
Denis Nerland	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 and currently sits on the Audit Committee of Crew Energy Inc., a public oil and gas company. 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.

Pre Approval of Policies and Procedures

InPlay has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PriceWaterhouseCoopers 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 PriceWaterhouseCoopers 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.

InPlay 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 InPlay and its subsidiaries for professional services rendered by PriceWaterhouseCoopers LLP, the Corporation’s external auditors, during fiscal 2016 and 2015:

	Aggregate fees billed	
	2016	2015
Audit fees	$175,000	$53,500
Audit-related fees	$231,500	-
Tax fees	$7,000	$3,500
All other fees	$116,240	-
	$529,740	$57,000

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

Audit-Related Fees. Comprised of fees for services related to the Transactions including property audits, preparation of 2015/2014 annual financial statements of Private InPlay and procedures in regards to preparation of the information circular-proxy Statement to Private InPlay shareholders in respect of the Transactions.

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

All Other Fees. Other services provided by InPlay’s external auditor other than audit, audit-related and tax services including financial and tax due diligence services provided in relation to completion of the Transactions.

HUMAN RESOURCES

InPlay currently employs 31 full-time employees, of which 26 are located in the head office and 5 are field employees, along with three part-time consultants. InPlay 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, including the governments of Canada and Alberta, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises 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, 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, regional market and transportation issues also influence prices. 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 licence from the NEB. The NEB underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was 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. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

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 per day) must be made pursuant to an NEB order. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas requires an exporter to obtain an export licence 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. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

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 where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum 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 Canadian federal government has signaled that 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 stringent reviews for pipelines and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

In Alberta, the Crown owns 81% of the province's mineral rights. The remaining 19% are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. 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 formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the "New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) (the "**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 total depth, length, and proppant placed). The new royalty rate for Pre-Payout under the MRF 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. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 194 m^3 (40 barrels of oil equivalent per day or 345,500 m^3 of gas per month), 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.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator ("**AER**").

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. 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% and 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 between 1% and 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 Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale 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 depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

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 lands where the Crown does not hold the rights to mines and minerals 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 freehold 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 ten-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.

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, licences, 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.

The province of Alberta has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence.

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 licences issued after January 1, 2009 at the conclusion of the primary term of the lease or licence.

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, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance 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 environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, 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. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

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 environmental 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.

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An Expert Panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel’s report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing LNG export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

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 provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

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, licences, 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.

Phase 1 Consultation of the North Saskatchewan Region Plan ("**NSRP**") has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act ("**OGCA**")* establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct or is unable to meet its obligations. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed 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. The AER publishes the liability management rating for each licensee on a monthly basis.

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.

On June 20, 2016, the AER issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("***Bulletin 16***") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re),* 2016 ABQB 278 ("***Redwater***"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA and the *Bankruptcy and Insolvency Act* ("***BIA"***), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the *BIA*. *Bulletin 16* provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

1. The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.
2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.
3. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in *Bulletin 16*, the AER issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("***Bulletin 21***") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, *Bulletin 21* did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

1. The licensee already has an LMR of 2.0 or higher;
2. The acquisition will improve the licensee's LMR to 2.0 or higher; or
3. The licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the *Redwater* decision on October 11, 2016, with the Court reserving its decision.

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 by suspending the wells in accordance with *Directive 013* or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

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.

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.

As 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), 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, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada’s INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

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

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 GHG emissions 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. As of 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.

A Regulated Emitter can meet its 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. On June 7, 2016, the *Climate Leadership Implementation Act* ("***CLIA***") was passed into law. The *CLIA* enacted the *Climate Leadership Act* ("***CLA***") introducing a carbon tax on all sources of GHG emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the *SGER* framework until the end of 2017; upon the expiry of the *SGER*, the Government of Alberta intends to transition to a proposed *Carbon Competitiveness Regulation*, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented 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. Regulations accompanying the *CLIA* have not yet been released.

The passing of the *CLIA* is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the *CLA*, the *CLIA* also enacted the *Energy Efficiency Alberta Act*, which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

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.

InPlay is in compliance with its reporting obligations under the current legislative regime.

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 participation uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

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

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

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

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

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

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, at the provincial level and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or 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 downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves rendering certain reserves uneconomic. In addition, lower commodity prices have affected, and are anticipated to continue to affect, the Corporation's cash flow resulting in a reduced capital expenditure budget. Consequently, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. 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, produced or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, 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 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, OPEC's recent decisions pertaining to the oil production of OPEC member countries and non-OPEC member countries' decisions on production levels, 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 production, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, political uncertainty, 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 by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation may realize less on disposition than their carrying value on the financial statements of the Corporation.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation.

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

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 reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse effect on the Corporation's financial and operational results.

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 overruns could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing and waterfloods, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the 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. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. In addition, the federal government has signaled that it plans to review the National Energy Board approval process for large federally regulated 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 and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Competition

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

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

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

Royalty Regimes

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 took 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.

Waterflood

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

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 oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

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

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 is unable to satisfy its obligation 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 to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance requirements. 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.

The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re*) 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces.

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) 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 would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the

Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, on January 1, 2017 the Climate Leadership Act ("**CLA**") come into effect in the Province of Alberta introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. 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. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is 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 and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

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

Credit Facility Arrangements

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

Hedging

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) as well as skilled personnel trained to use such equipment in the particular areas where such activities will be conducted. Demand for such limited equipment and skilled personnel or access restrictions, may affect the availability of such equipment and skilled personnel to the Corporation and may delay exploration and development activities.

Diluent Supply

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 a defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

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

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

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

Insurance

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, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

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

Aboriginal Claims

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

Breach of Confidentiality

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

Income Taxes

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. 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. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. 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 personnel insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Information Technology Systems and Cyber-Security

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

Further, the Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Expansion into New Activities

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 risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

InPlay 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, 2016, nor is InPlay 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 InPlay.

During the year ended December 31, 2016, 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 InPlay, 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 InPlay. Certain directors, officers and insiders of InPlay have and may continue to participate in public offerings or private placements of equity securities undertaken by InPlay from time to time. Any such participation is on the same basis as all other subscribers to such offerings.

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 InPlay Shares.

MATERIAL CONTRACTS

Other than the Arrangement Agreement and the InPlay Credit Facility, and 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 PriceWaterhouseCoopers 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 InPlay's outstanding securities, including securities of InPlay'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. PriceWaterhouseCoopers 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 18, 2017. 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 InPlay's information circular, comparative consolidated financial statements, including any interim consolidated comparative financial statements and additional copies of the Annual Information Form please contact:

InPlay Oil Corp.
Suite 920, 640 – 5th Avenue S.W.
Calgary, Alberta T2P 3G4
Tel: 587-955-9570
Fax: 587-955-0630
www.InPlayoil.com

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

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

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 23rd day of March, 2017.

(signed) "*Douglas Bartole*"
Douglas Bartole
President and Chief Executive Officer

(signed) "*Darren Dittmer*"
Darren Dittmer
Chief Financial Officer

(signed) "*Dale Shwed*"
Dale Shwed
Director and Chairman of the Reserves Committee

(signed) "*Donald Cowie*"
Donald Cowie
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 InPlay Oil Corp. (the "**Corporation**"):

1. We have evaluated the Corporation's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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, 2016, 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 (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule Associates Limited	December 31, 2016	Canada	Nil	317,311	Nil	317,311

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 InPlay Oil Corp. (As of December 31, 2016)".

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
March 23, 2017

(signed) "*Richard A. Brekke*"
Richard A. Brekke
Senior Manager, Engineering

(signed) "*Ian K. Kirkland*"
Ian K. Kirkland
Senior Petroleum Geologist

(signed) "*Alec Kovaltchouk*"
Alec Kovaltchouk
Vice President, Geosciences

(signed) "*Cam P. Six*"
Cam P. Six
President, Chief Executive Officer & Director

APPENDIX "C"
INPLAY OIL CORP.
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 InPlay Oil Corp. ("InPlay" 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 InPlay 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 InPlay 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 InPlay's internal control systems.

3. Review the annual and interim financial statements of InPlay 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 InPlay'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 InPlay 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 InPlay) their assessment of the internal controls of InPlay, 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 InPlay and its subsidiaries.

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

8. Establish a procedure for:

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

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

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

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 InPlay. All employees of InPlay 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 InPlay 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.