Management's Discussion and Analysis

For the three and nine months ended September 30, 2017

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2017 AND SEPTEMBER 30, 2016

The following management's discussion and analysis ("**MD&A**") is dated November 10, 2017 and should be read in conjunction with the unaudited financial statements of InPlay Oil Corp. ("**InPlay**" or the "**Company**") for the three and nine months ended September 30, 2017 and September 30, 2016. The financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") and interpretations of the IFRS Interpretations Committee, applicable to the preparation of interim financial statements, including IAS 34, Interim Financial Reporting.

In addition to generally accepted accounting principles ("**GAAP**") measures, this MD&A contains additional conversion measures, non-GAAP measures, and forward-looking statements. Readers are cautioned that the MD&A should be read in conjunction with InPlay's disclosure under the headings "Conversion Measures and Short-Term Production Rates", "Non-GAAP Measures", and "Forward-Looking Statements" included at the end of this MD&A.

All references to dollar values are to Canadian dollars unless otherwise stated. Production volumes are measured upon sale unless otherwise noted. Definitions of the abbreviations used in this discussion and analysis are located on the last page of this document.

ABOUT INPLAY

InPlay is a crude oil and natural gas exploration, development and production company with operations in Alberta. InPlay's strategic plan is to build a sustainable long-term oil and natural gas company. This plan is based on acquiring low decline, high operating netback producing properties with drilling development potential and enhanced oil recovery potential as well as undeveloped lands with exploration and development upside.

On November 7, 2016, a plan of arrangement (the "**Arrangement**") involving the predecessor to InPlay ("**Prior InPlay**") and Anderson Energy Inc. ("**Anderson**"), a publicly-traded company listed on the Toronto Stock Exchange (the "**TSX**"), was completed that constituted a reverse acquisition, including a change of control of Anderson and a business combination of Anderson and Prior InPlay to form a new corporation that now carries on Prior InPlay's and Anderson's business and operations under the name "**InPlay Oil Corp.**". InPlay has the same directors and management as Prior InPlay. Effective November 10, 2016 the InPlay common shares commenced trading on the TSX under the symbol "IPO" in substitution of the Anderson common shares.

In connection with the Arrangement, Prior InPlay completed a subscription receipt financing for aggregate gross proceeds of approximately $70.3 million (the "**InPlay Financing**"). The outstanding common shares of Prior InPlay ("**Prior InPlay Shares**") and subscription receipts ("**Prior InPlay Subscription Receipts**") issued under the InPlay Financing were, through a series of steps under the Arrangement, exchanged for common shares of InPlay ("**InPlay Shares**") on the basis of 0.1303 of an InPlay Share for each one (1) Prior InPlay Share and each one (1) Prior InPlay Subscription Receipt previously held (the "**InPlay Exchange Ratio**"). Holders of Anderson common shares continued to hold one (1) InPlay Share for each one (1) Anderson common share previously held without any action on their part. The number of commons shares for all periods shown in this MD&A were adjusted retrospectively to reflect the InPlay Exchange Ratio.

Also part of the Arrangement noted above, InPlay acquired additional assets from a third party that included undeveloped lands, producing assets and interests in various facilities in the Pembina area of Alberta, Canada (the "**Asset Acquisition**").

Since the Arrangement involved a reverse acquisition whereby Prior InPlay acquired control of the business of Anderson (the "**Corporate Acquisition**"), management has prepared the financial statements and this MD&A for the business formerly owned by Prior InPlay under the name of InPlay Oil Corp. The results for periods of the Company prior to November 7, 2016 are those previously reported by Prior InPlay, and beginning November 7, 2016 the results include the contributions from the Corporate Acquisition and Asset Acquisition.

REVIEW OF FINANCIAL RESULTS

Production

Average production volumes for the three and nine month periods ended September 30, 2017 and September 30, 2016 were as follows:

Production by Product	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Crude oil (bpd)	**2,403**	1,093	**2,245**	1,250
NGLs (bpd)	**381**	92	**346**	105
Natural gas (Mcfd)	**7,820**	1,654	**7,854**	1,958
Total (BOED)(1)	**4,087**	1,460	**3,900**	1,681

(1) Barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. Refer to the section entitled "Conversion Measures and Short-term Production Rates" at the end of this MD&A.

Production for the third quarter and first nine months of 2017 was higher than the third quarter and first nine months of 2016 due to the additional volumes from the Corporate Acquisition and the Asset Acquisition as well as additional volumes from the drilling program that started in the fourth quarter of 2016 and continued into the first nine months of 2017.

The drilling and completion program beginning in the fourth quarter of 2016 continued into the first nine months of 2017 with the completion of 2.0 wells drilled in 2016 and an additional 8.0 (6.1 net) Cardium horizontal wells being drilled. Of these drills, 1.0 gross (1.0 net) well was completed in January and put on production mid-February, 3.0 gross (1.3 net) wells were completed in late March and placed on production early in April, 1.0 gross (1.0 net) Willesden Green horizontal 1-mile well was completed in May and put on production in late June, 1.0 gross (0.8 net) well was completed in June and put on production in July, 1.0 gross (1.0 net) well which was drilled in January was completed in August and put on production in September and 1.0 gross (1.0 net) 2-mile extended Willesden Green horizontal well was drilled and completed in July and put on production in August. The drilling of an additional 3.0 gross (3.0 net) wells started in October and are currently being completed.

Crude oil and natural gas sales

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Crude oil and NGLs	**13,143**	5,341	**38,809**	16,327
Natural gas	**1,346**	340	**5,413**	944
Total crude oil and natural gas sales	**14,489**	5,681	**44,222**	17,271

Average realized prices:

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Crude oil and NGLs ($/bbl)	**51.31**	49.02	**54.86**	43.99
Natural gas ($/Mcf)	**1.87**	2.24	**2.52**	1.76
Total ($/BOE)	**38.53**	42.28	**41.53**	37.50
WTI ($US/bbl)	**48.20**	44.94	**49.47**	41.33

Prices

Crude oil and natural gas prices improved in the third quarter of 2017 compared to average prices during the third quarter of 2016. In the third quarter of 2017, WTI oil prices increased 7% averaging $48.20 US per bbl compared to $44.94 US per bbl in the third quarter of 2016. Crude oil prices increased significantly in the first nine months of 2017 compared to 2016, with WTI oil prices averaging $49.47 US per bbl in the first nine months of 2017 compared to $41.33 US per bbl in the first nine months of 2016.

Differentials between WTI oil prices and prices received in Alberta are volatile due to factors including refining demand and pipeline capacity. InPlay sells its oil at monthly average Edmonton Par prices less quality differentials, transportation and marketing fees. Light, sweet oil differentials between Cushing, Oklahoma and Edmonton, Alberta are affected by transportation and market factors. These differentials decreased, averaging $2.89 US per barrel discount for the third quarter of 2017 compared to $2.97 US per barrel for the third quarter of 2016. The discount decreased for the nine months ended September 30, 2017, averaging $2.90 US per barrel discount for the first nine months of 2017 compared to $3.25 US per barrel for the first nine months of 2016. Realized oil prices are also adjusted for the Canada/US exchange rate which increased averaging 0.80 for the third quarter of 2017 compared to 0.77 for the third quarter of 2016. The Canada/US exchange rate remained relatively constant for the nine months ended September 30, 2017 and September 30, 2016 at 0.77 and 0.76 respectively.

Third quarter 2017 realized prices decreased compared to the third quarter of 2016. The Company's average price for crude oil was $54.32 per bbl for the quarter ended September 30, 2017, 6% higher than the third quarter 2016 price of $51.35 per bbl. Realized natural gas prices decreased over the two respective periods. The Company's average natural gas sales price was $1.87 per Mcf for the three months ended September 30, 2017, 17% lower than the third quarter of 2016 price of $2.24 per Mcf. AECO prices were significantly reduced throughout the quarter as a result of cut backs on deliveries imposed on the Trans Canada system. These reduction carry into the fourth quarter of 2017 but are expected to eventually be rectified.

Realized prices for the first nine months of 2017 increased compared to the first nine months of 2016. The Company's average price for crude oil was $58.18 per bbl for the nine months ended September 30, 2017, 26% higher than the first nine months of 2016 price of $46.05 per bbl. Realized natural gas prices also increased over the two respective periods. The Company's average natural gas sales price was $2.52 per Mcf for the nine months ended September 30, 2017, 43% higher than the nine months ended September 30, 2016 price of $1.76 per Mcf.

Royalties

Production coming from new wells drilled by the Company on Crown lands qualify for royalty incentives that reduce average Crown royalties for periods of up to 48 months from initial production, after the Crown royalties from these wells will come off this incentive period and be subject to the regular Alberta royalty structure.

Royalties as a percentage of total oil and natural gas sales are highly sensitive to prices and adjustments to gas cost allowance and so royalty rates can fluctuate from quarter-to-quarter and year-to-year. Royalties, as a percentage of crude oil and natural gas sales and royalties per BOE are as follows:

	Three months ended September 30		Nine months ended September 30	
	2017	2016	**2017**	2016
Total royalties ($'000s)	**1,509**	531	**4,505**	1,532
Total royalties (% of sales)	**10.4%**	9.3%	**10.2%**	8.8%
Total royalties ($/BOE)	**4.01**	3.95	**4.23**	3.33

Royalty rates as a percentage of sales are up slightly for the third quarter and first nine months of 2017 compared to the third quarter and first nine months of 2016 tracking higher commodity prices received over the two respective periods.

Derivative contracts

The Company's production is usually sold using "spot" or near-term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company may selectively economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts.

At September 30, 2017 the following commodity-based derivative contracts were outstanding and recorded at estimated fair value:

Swap natural gas AECO derivative contracts:

Currency denomination	Volume (GJ/day)	Average swap price	Term ending	Fair value ($'000 CAD)
Canadian dollar	1,000	3.055/GJ	March 31, 2018	$151
Canadian dollar	2,000	2.51/GJ	October 31, 2017	$64
Canadian dollar	1,000	2.95/GJ	March 31, 2018	$132
Canadian dollar	1,000	3.04/GJ	December 31, 2017	$95

Costless collar[(1)] crude oil WTI derivative contracts:

Currency denomination	Volume (bpd)	Sold call price	Sold put price	Term ending	Fair value ($'000 CAD)
Canadian dollar	200	55.00/bbl	73.65/bbl	December 31, 2017	-
Canadian dollar	200	55.00/bbl	74.00/bbl	December 31, 2017	$1
US dollar	200	47.50/bbl	57.80/bbl	December 31, 2017	$5
US dollar	500	47.00/bbl	59.60/bbl	December 31, 2017	$16
US dollar	200	47.00/bbl	52.00/bbl	March 31, 2018	($66)
US dollar	200	46.00/bbl	53.00/bbl	June 30, 2018	($86)
US dollar	200	46.00/bbl	53.40/bbl	June 30, 2018	($73)

(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.

Subsequent to September 30, 2017 the Company entered into crude oil derivative contracts as follows:

Swap crude oil WTI derivative contracts:

Currency denomination	Volume (bpd)	Average swap price	Term ending
US dollar	500	57.00/bbl	June 30, 2018

Costless collar crude oil WTI derivative contract:

Currency denomination	Volume (bpd)	Sold call price	Sold put price	Term ending
US dollar	300	48.00/bbl	57.00/bbl	December 31, 2018

The statements of (loss) and comprehensive (loss) for the three and nine months ended September 30, 2017 reflected the following gains/(losses) related to derivative contracts that were outstanding during 2017 and the comparative periods for 2016:

	Three months ended September 30		Nine months ended September 30	
(thousands of dollars)	**2017**	2016	**2017**	2016
Realized gain	**413**	140	**954**	2,916
Unrealized gain (loss)	**(695)**	186	**1,787**	(3,626)
Total gain (loss) on derivative contracts	**(282)**	326	**2,741**	(710)

Operating expenses

	Three months ended September 30		Nine months ended September 30	
(thousands of dollars)	**2017**	2016	**2017**	2016
Total operating costs	**6,616**	2,475	**17,417**	7,931
Total operating costs ($/BOE)	**17.60**	18.42	**16.36**	17.22

Operating costs include expenses incurred to operate the wells, gather and treat production volumes as well as costs to perform well and facility repairs and maintenance. For the three months ended September 30, 2017, operating expenses decreased to $17.60 per BOE compared to $18.42 per boe for the three months ended September 30, 2016 and for the nine months ended September 30, 2017, operating expenses decreased to $16.36 per BOE compared to $17.22 per boe for the nine months ended September 30, 2016 reflecting improvements in operating efficiencies over the respective periods. Total operating costs are up in the three and nine months ended September 30, 2017 compared to the three and nine months ended September 30, 2016 as a result of the Corporate Acquisition and the Asset Acquisition. Operating costs of $6.6 million ($17.60/boe) incurred during the third quarter of 2017 were slightly higher in the quarter due to some unplanned but necessary expenditures. During the quarter we initiated several sand cleanouts of wells. These included three wells that were sanded in by third party fracture completion operations on offsetting lands. As well, high production rates from some of our new wells coming on production could not be handled at the facilities they were tied into resulting in the need to rent and install temporary equipment, services and to temporarily truck the high volume of fluids. These volumes are now going through normal processing facilities. We expect operating costs going forward should track rates per boe realized in the first half of 2017.

Transportation expenses

(thousands of dollars)	Three months ended September 30 2017	2016	Nine months ended September 30 2017	2016
Total transportation expense	**206**	86	**702**	389
Total transportation expense ($/BOE)	**0.55**	0.64	**0.66**	0.84

Transportation expenses include costs incurred to transport processed crude oil, liquids and natural gas products to the point of sale, as well as firm-service take or pay contracts that InPlay has secured directly to transport its natural gas. Expenses incurred to transport production that is not yet in a suitable condition to be shipped on a common-carrier pipeline from the well or battery to a cleaning facility or fractionation plant are included within operating expenses.

For the three months ended September 30, 2017, transportation expenses were $0.55 per BOE compared to $0.64 per BOE for the three months ended September 30, 2016. For the nine months ended September 30, 2017, transportation expenses were $0.66 per BOE compared to $0.84 per BOE for the nine months ended September 30, 2016. Transportation expenses per BOE decreased for the three and nine months ended 2017 compared to the same periods in 2016 as several short term firm service contracts entered into in 2016 at higher rates ended in the second and fourth quarters of 2016. Firm services natural gas contracts are entered into to ensure that associated and non-associated natural gas production will have access to transportation capability.

Operating Netback

(thousands of dollars)	Three months ended September 30 2017	2016	Nine months ended September 30 2017	2016
Revenue(1)	**14,489**	5,681	**44,222**	17,271
Royalties	**(1,509)**	(531)	**(4,505)**	(1,532)
Operating expenses	**(6,616)**	(2,475)	**(17,417)**	(7,931)
Transportation expenses	**(206)**	(86)	**(702)**	(389)
Operating netback (2)	**6,158**	2,589	**21,598**	7,419
Sales volume (MBOE)	**376.0**	134.4	**1,064.8**	460.6
Per BOE				
Revenue(1)	**38.53**	42.27	**41.53**	37.50
Royalties	**(4.01)**	(3.95)	**(4.23)**	(3.33)
Operating expenses	**(17.60)**	(18.42)	**(16.36)**	(17.22)
Transportation expenses	**(0.55)**	(0.64)	**(0.66)**	(0.84)
Operating netback per BOE (2)	**16.37**	19.26	**20.28**	16.11

(1) Includes royalty and other income classified with oil and natural gas sales.
(2) Operating netback and operating netback per BOE are considered non-GAAP measures. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

Total operating netbacks increased for the third quarter and first nine months of 2017 compared to the third quarter and first nine months of 2016 due to the additional operating income assumed from the properties from the Corporate Acquisition and Asset Acquisition. Increased prices over the two respective periods also resulted in increased total operating income in the third quarter and first nine months of 2017. Operating netbacks per boe decreased for the third quarter of 2017 compared to 2016 largely due to the 9% decrease in net realized prices. Operating netbacks per boe increased for the first nine months of 2017 compared to 2016 largely due to the 11% increase in net realized prices.

General and administrative ("G&A") expenses

The following table is a reconciliation of the Company's gross G&A expenditures to general and administrative expenses:

	Three months ended September 30		Nine months ended September 30	
(thousands of dollars)	**2017**	2016	**2017**	2016
Gross G&A expenses	**1,696**	1,134	**5,060**	3,316
Capitalized and recoveries	**(246)**	(220)	**(864)**	(678)
Total G&A expense	**1,450**	914	**4,196**	2,638
Total G&A expense ($/BOE)	**3.86**	6.80	**3.94**	5.73
% Capitalized	**15%**	19%	**17%**	20%

Total G&A expense for the three and nine months ended September 30, 2017 increased compared to the three and nine months ended September 30, 2016 following the additional employees, office lease, systems and public reporting costs incurred following the Arrangement and Asset Acquisition. G&A expenses on a per BOE basis are lower over the same respective periods reflecting the higher level of production in the three and nine months ended September 30, 2017 relative to the additional costs.

Share-based compensation expenses

The Company accounts for share-based compensation using the fair value method of accounting, and share-based compensation (net of amounts capitalized) is included in the determination of profit (loss) and comprehensive income (loss). For the three and nine months ended September 30, 2016 the Company's share-based compensation relates to two incentive plans adopted by the Company: a stock option plan pursuant to which options to purchase common shares at specified exercise prices may be granted to directors, officers, employees and service providers of the Company, and a historical performance warrant incentive plan that was terminated upon completion of the Arrangement. For the three and nine months ended September 30, 2017 there is only a stock option plan similar to the previous stock option plan.

	Three months ended September 30		Nine months ended September 30	
(thousands of dollars)	**2017**	2016	**2017**	2016
Share-based compensation	**602**	561	**1,769**	2,102
Capitalized portion	**(193)**	(202)	**(568)**	(614)
Share-based compensation expense	**409**	359	**1,201**	1,488

All outstanding Prior InPlay stock options and performance warrants were surrendered for cancellation in conjunction with the completion of the Arrangement in the fourth quarter of 2016. In the first nine months of 2017 4,955,400 options were granted of which 12,000 of these were forfeited within the nine months ended September 30, 2017. At September 30, 2017 the maximum number of stock options available for grant was 6,205,357. The performance warrant incentive plan has been terminated and no further performance warrants will be issued under this plan.

Depletion and depreciation

(thousands of dollars)	Three months ended September 30 **2017**	2016	Nine months ended September 30 **2017**	2016
Total Depletion and depreciation	**5,590**	2,732	**16,394**	9,750
Total Depletion and depreciation ($/BOE)	**14.87**	20.33	**15.40**	21.17

The carrying costs for property, plant and equipment ("PP&E") directly associated with crude oil and natural gas operations, including estimated future development costs, are recognized as depletion expense in the statements of profit (loss) and comprehensive income (loss) on a unit of production basis over proved plus probable reserves. The carrying costs of office and computer equipment are recognized as depreciation expense in the statements of profit (loss) and comprehensive income (loss) on a straight-line or declining-balance basis.

Depletion and depreciation was $5.6 million ($14.87 per BOE) for the three months ended September 30, 2017 compared to $2.7 million ($20.33 per BOE) for the three months ended September 30, 2016. Depletion and depreciation was $16.4 million ($15.40 per BOE) for the nine months ended September 30, 2017 compared to $9.8 million ($21.17 per BOE) for the nine months ended September 30, 2016. The reduced rate over the respective periods is attributable to two factors. Firstly, the impairment of PP&E assets recognized in the third quarter of 2016 which resulted in lower net book values in the third quarter and first nine months of 2017 subject to depletion and depreciation without a corresponding reduction in proven plus probable reserves volumes. Secondly, the additional proved and probable reserves acquired through the Arrangement and Asset Acquisition relative to the additional depletable PP&E assets acquired contributed to this decrease.

Finance expenses

Finance expenses were $0.9 million for the third quarter of 2017, compared to $0.4 million for the third quarter of 2016. Finance expenses were $2.2 million for the first nine months of 2017, compared to $1.4 million for the first nine months of 2016.

(thousands of dollars)	Three months ended September 30 **2017**	2016	Nine months ended September 30 **2017**	2016
Interest expense (Credit Facility and other)	**459**	388	**1,085**	1,160
Accretion on decommissioning obligation	**447**	60	**1,117**	231
Finance expenses	**906**	448	**2,202**	1,391

Interest expense on credit facilities tracks the draw on the bank line over the quarterly period. Interest expense in the third quarter and first nine months of 2017 is determined in accordance with the new senior secured revolving credit facility (see note 8 in the unaudited financial statements for the three and nine months ended September 30, 2017 and September 30, 2016). Higher accretion expense in the third quarter and first nine months of 2017 is reflective of the increased decommisioning obligations acquired through the Arrangement and Asset Acquisition Agreement.

Income taxes

The Company has recognized a deferred tax asset in the amount of $56.0 million at September 30, 2017.

The deferred tax asset is supported by the expected future utilization of tax attributes based upon future cashflows derived from the company's independent year end reserve report using the total proven and probable cashflows and expenditures and factoring in expected corporate general and administrative and interest expenses.

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at September 30, 2017.

Non-capital loss carryforward balances	59,079
Share issue costs & ECE	3,117
Canadian Exploration Expenses (CEE)	64,522
Canadian Development Expenses (CDE)	63,641
Canadian Oil and Gas Property Expenses (COGPE)	145,274
Undepreciated Capital Cost (UCC)	43,282
Total	378,915

Capital Expenditures

Capital expenditures were $8.3 million and $23.5 million for the three and nine months ended September 30, 2017 respectively. The Company spent $0.2 million and $3.7 million on capital expenditures in the three and nine months ended September 30, 2016.

The breakdown of expenditures is shown below:

	Three months ended September 30		Nine months ended September 30	
(thousands of dollars)	**2017**	2016	**2017**	2016
Land and lease	**25**	11	**333**	28
Drilling, completions & workovers	**7,031**	4	**17,625**	2,568
Facilities and equipping costs	**960**	3	**3,284**	532
Total exploration and development capital	**8,016**	18	**21,242**	3,128
Office & Capitalized G&A	**276**	202	**989**	616
Total	**8,292**	220	**22,231**	3,744
Net Property Acquisitions	**-**	-	**1,220**	-
Total capital expenditures	**8,292**	220	**23,451**	3,744

Expenditures on property acquisitions include $1.5 million relating to an asset acquisition which closed in June of 2017, net of $0.3 million received as a result of the final statement of adjustments relating to the November 7, 2016 Asset Acquisition. See note 5 to the Company's unaudited financial statements for the three and nine months ended September 30, 2017 and September 30, 2016. Capital costs in the quarter also included re-entry and facility upgrade programs.

The drilling and completion program beginning in the fourth quarter of 2016 continued into the first nine months of 2017 with the completion of 2.0 wells drilled in 2016 and an additional 8.0 (6.1 net) Cardium horizontal wells being drilled. Of these drills, 1.0 gross (1.0 net) well was completed in January and put on production mid-February, 3.0 gross (1.3 net) wells were completed in late March and placed on production early in April, 1.0 gross (1.0 net) Willesden Green horizontal 1-mile well was completed in May and put on production in late June, 1.0 gross (0.8 net) well was completed in June and put on production in July, 1.0 gross (1.0 net) well which was drilled in January was completed in August and put on production in September and 1.0 gross (1.0 net) 2-mile extended Willesden Green horizontal well was drilled and completed in July and put on production in August. The drilling of an additional 3.0 gross (3.0 net) wells started in October and are currently being completed.

The Company also spent $0.2 million on undeveloped land in the Willesden Green area during the nine months ended September 30, 2017.

Subsequent to September 30, 2017, the Company spent $13.9 million on undeveloped land at the crown land sales in the Huxley area.

Drilling statistics are as follows:

	Three months ended September 30				Nine months ended September 30			
	2017		2016		**2017**		2016	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**1.0**	**1.0**	-	-	**8.0**	**6.1**	2.0	2.0
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**1.0**	**1.0**	-	-	**8.0**	**6.1**	2.0	2.0
Success rate	**100%**	**100%**	-	-	**100%**	**100%**	100%	100%

SHARE INFORMATION

The Company's common shares are listed on the Toronto Stock Exchange under the symbol IPO.

As of November 10, 2017, there were 63,053,569 common shares outstanding and 4,865,400 stock options that were convertible into, or exercisable or exchangeable for, an equivalent number of common shares of the Company. All previously held stock options and performance warrants of Prior InPlay were cancelled in conjunction with the completion of the Arrangement on November 7, 2016.

Subsequent to the quarter end, InPlay determined to issue, by way of a non-brokered private placement financing on a "flow-through" basis, up to $10 million in common shares in respect of a combination of Canadian development expenses ("**CDE**") at a price of $1.70 per share ("**CDE Shares**") and Canadian exploration expenses ("**CEE**") at a price of $1.80 per share ("**CEE Shares**") (the "**Private Placement**"). Proceeds of the Private Placement will be used to incur eligible CDE and CEE, as the case may be.

To date, the Corporation has completed the sale and issuance of an aggregate of 1 million CEE Shares for gross proceeds of $1.8 million. The balance of the Private Placement is expected to close in one or more additional tranches mid to late November, 2017 and remains subject to receipt of all necessary approvals including the approval of the Toronto Stock Exchange. The common shares issued pursuant to the Private Placement are subject to a statutory hold period of four months plus one day from the date of issuance in accordance with applicable securities legislation.

RELATED PARTY TRANSACTIONS

InPlay had no related party transactions that were entered into under the normal course of business for the nine months ended September 30, 2017. For the nine months ended September 30, 2016, a director of the Company was an executive officer of a corporation to which the Company made office lease payments in the amount of $0.3 million during the nine months ended September 30, 2016. The lease term ended in November 2016 and no amounts were outstanding as of December 31, 2016.

LIQUIDITY AND CAPITAL RESOURCES

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility which will allow it to fund its ongoing capital expenditure program, provide creditor and market confidence and to sustain the future development of the business. The Company is able to maintain high funds flow netbacks even while facing low commodity prices which in turn provides strong cash flows which assist in managing its working capital and capital requirements.

In November 2016 the Company concluded a financing in conjunction with the closing of the Arrangement that included common share issuances totaling $70.3 million of gross proceeds. The proceeds were used to fund the Asset Acquisition, to incur qualifying exploration and development expenditures, to reduce indebtedness, and for general working capital purposes.

At September 30, 2017, the Company has a $60.0 million senior secured revolving credit facility (the "Credit Facility") with a syndicate of Canadian financial institutions (the "Lenders"). The Credit Facility consists of a $50 million revolving line of credit and a $10 million operating line of credit. The Credit Facility has a term date of May 31, 2018, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable one year later on May 31, 2019. The Credit Facility is secured by a floating charge debenture and a general security agreement on the assets of the Company. At September 30, 2017 the Company had drawn $36.9 million on the credit facility following the active fourth quarter 2016 and first nine months of 2017 drilling program. The available lending limit of the Credit Facility is scheduled for the semi-annual review on or before November 30, 2017 and is based on the Lenders' interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount or terms of the available Credit Facility will not be adjusted at the next review. In the event that the lenders reduced the borrowing base below the amount drawn at the time of the redetermination, the Company would have 60 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

In addition, the Company had a working capital (deficit) of ($5.1) million. The Company expects to have a higher level of current liabilities at September 30, 2017 due to the increased amounts of accounts payable and accrued liabilities related to the drilling program in the first nine months of 2017. There are standard reporting covenants under the Credit Facility however there are no financial covenants.

OFF-BALANCE SHEET ARRANGEMENTS

The Company had no guarantees or off-balance sheet arrangements other than as described below under "Contractual Obligations."

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. At September 30, 2017, these obligations include:

- **Loan agreement** – The reserves-based, extendable, committed-term Credit Facility has a term date of May 31, 2018. If not extended, any outstanding advances would become repayable on May 31, 2019.

- **Firm service transportation commitments** – The Company has entered into firm service transportation agreements. Fees related to transportation periods subsequent to September 30, 2017 were not recognized as a liability at September 30, 2017.

- **Flow-through share capital commitments** – As at September 30, 2017, the Company had $1.7 million remaining of its commitment to incur qualifying Canadian exploration expenditures related to the $3.8 million raised from the issuance of flow-through shares in conjunction with the closing of the Arrangement on November 7, 2016. These remaining commitments were not recognized as liabilities at September 30, 2017. The Company expects to incur this remaining expenditure in 2017.

As at September 30, 2017 the Company had the following minimum contractual obligations:

Contractual obligations (in thousands of dollars)	Payments due by year 2017	2018	2019	2020	2021	Thereafter
Accounts payable	16,572	-	-	-	-	-
Bank debt(1)	-	-	36,911	-	-	-
Non-cancellable office leases(2) (3)	190	379	29	-	-	-
Flow-through share spending commitments	1,707					
Firm service(3)	102	445	259	90	68	221
Total	18,571	824	37,199	90	68	221

(1) Assumes the Credit Facility is not renewed as of May 31, 2018, and the entire outstanding balance becomes payable on May 31, 2019.

(2) Includes the head office lease net of sublease income.

(3) Both parties are entitled to terminate the lease agreement at any point after January 31, 2019 provided six months notice is provided to the other party. This commitment table above assumes that this termination will occur on February 1, 2019.

(4) These transportation charges are netted from revenue received from purchasers. The independent Company's reserves evaluation includes the cost of product transportation in the determination of reserves values.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is a defendant in various legal actions and other disputes arising in the normal course of business. The Company believes that any liabilities that may arise pertaining to these matters will not have a material effect on its financial position.

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 3 to the financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results than reported. The Company's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results that differ materially from current estimates.

Oil and natural gas reserves

Proved and probable reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the COGE Handbook, are estimated using independent reserves evaluator reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50% statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90% and 10%, respectively. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering, production and any other relevant data. These estimates are subject to material change as economic conditions change and ongoing production and development activities provide new information.

Purchase price allocations and calculations of depletion and depreciation, impairment loss and deferred income tax assets are based on estimates of oil and natural gas reserves. Reserves estimates are based on engineering data, estimated future prices, expected future rates of production and timing of future capital expenditures. By their nature, these estimates are subject to measurement uncertainties and interpretations and the impact on the financial statements could be material. The Company expects that over time, its reserves estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels and may be affected by changes in commodity prices.

Recoverable amounts of CGUs

The recoverable amount of a CGU used in the assessment of impairment is the greater of its value-in-use ("**VIU**") and its fair value less costs to sell ("**FVLCTS**"). VIU is determined by estimating the present value of the future net cash flows from the continued use of the CGU, and is subject to the risks associated with estimating the value of reserves. FVLCTS refers to the amount obtainable from the sale of a CGU in an arm's length transaction between knowledgeable, willing parties, less costs of disposal. The criteria used in the estimation of this amount are discussed in note 5 to the financial statements.

Both VIU and FVLCTS estimates include the estimated reserves values in their determination. The key assumptions and estimates of the value of oil and natural gas reserves and the existing and potential markets for the Company's oil and natural gas assets are made at the time of reserves estimation and market assessment and are subject to change as new information becomes available. Changes in international and regional factors, including supply and demand of commodities, inventory levels, drilling activity, currency exchange rates, weather, geopolitical and general economic environment factors, may result in significant changes to the estimated recoverable amounts of CGUs.

Decommissioning obligations

The Company is required to set up a provision for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to property, plant and equipment and the appropriate liability account over the expected service life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of the economic life of the asset, costs associated with abandonment and site restoration, discount rates and review of potential abandonment methods.

Income taxes

The determination of the Company's income and other tax assets and liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax asset or liability may differ from that estimated and recorded by management. The Company estimates its future income tax rate in calculating its future income tax asset or liability. Various assumptions are made in assessing when temporary differences will reverse and this may impact the rate used.

NEW AND PENDING ACCOUNTING STANDARDS

Standards that are issued and that the Company reasonably expects to be applicable at a future date are listed below.

IFRS 9 "Financial Instruments". On July 24, 2015 the IASB issued the complete IFRS 9 ("IFRS 9 (2015)"). The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted. The restatement of prior periods is not required and is only permitted if information is available without the use of hindsight. IFRS 9 (2015) introduces new requirements for the classification and measurement of financial assets. Under IFRS 9 (2015), financial assets are classified and measured based on the business model in which they are held and the characteristics of their contractual cash flows. The standard introduces additional changes relating to financial liabilities. It also amends the impairment model by introducing a new 'expected credit loss' model for calculating impairment. IFRS 9 (2015) also includes a new general hedge accounting standard which aligns hedge accounting more closely with risk management. This new standard does not fundamentally change the types of hedging relationships or the requirement to measure and recognize ineffectiveness, however it will provide more hedging strategies that are used for risk management to qualify for hedge accounting and introduce more judgment to assess the effectiveness of a hedging relationship. The Company intends to adopt IFRS 9 (2015) in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of the adoption of this standard has not yet been determined.

IFRS 15 "Revenue from Contracts with Customers". In May 2015, the IASB issued IFRS 15 Revenue from Contracts with Customers ("IFRS 15"). The new standard is effective for annual periods beginning on or after January 1, 2018. Earlier adoption is permitted. The standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized. The new standard applies to contracts with customers. It does not apply to insurance contracts, financial instruments or lease contracts, which fall in the scope of other IFRSs. The Company intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of the adoption of this standard has not yet been determined.

IFRS 16 "Leases". On January 13, 2016 the IASB issued IFRS 16 Leases. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. The standard will come into effect for annual periods beginning on or after January 1, 2019 with earlier adoption permitted. The Company intends to adopt IFRS 16 in its financial statements for the annual periods beginning on January 1, 2019. The extent of the impact of the adoption of this standard has not yet been determined.

CHANGES IN ACCOUNTING POLICIES

There were no new or amended accounting standards or interpretations adopted in during the nine months ended September 30, 2017.

CONTROLS AND PROCEDURES

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on July l, 2017 and ended on September 30, 2017 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

BUSINESS RISKS

Oil and natural gas exploration and production is capital intensive and involves a number of business risks including, without limitation, the uncertainty of finding new reserves, the instability of commodity prices, weather, and various operational risks. Commodity prices are influenced by local and worldwide supply and demand, OPEC actions, ongoing global economic concerns, the US dollar exchange rate, transportation costs, political stability, and seasonal and weather-related changes to demand. The concern over increasing US natural gas production, driven primarily by the US shale gas plays, continues to depress the natural gas futures market. Oil prices declined sharply in the latter part of 2015 and throughout 2016 and into 2017, and continue to remain volatile as oil is a geopolitical commodity, affected by concerns about global economic markets, continued instability in oil producing countries and increases in production from US tight oil plays. Differentials between WTI oil prices and prices received in Alberta are volatile. The industry is subject to extensive governmental regulation with respect to the environment. Over the past year, several new environmental regulations at both the Federal and Provincial level were announced, though the details of how some of the regulations will be implemented have yet to be released. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain and maintain drilling licenses and other regulatory approvals, ability to obtain equipment, expiration of licenses and leases, competition from other producers, third-party transportation and processing disruption issues, sufficiency of insurance, ability to manage growth, reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These risks are described in more detail in the Company's most recent AIF filed with certain Canadian securities regulatory authorities on SEDAR at www.sedar.com.

The Company makes substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near-term industry activity coupled with the present global economic concerns exposes the Company to additional access-to-capital risk. There can be no assurance that debt or equity financing, or funds 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 Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

InPlay manages these risks by employing competent and professional staff, following sound operating practices and using capital prudently. The Company generates its exploration and development prospects internally and performs extensive geological, geophysical, engineering, and environmental analysis before committing to the drilling of new prospects. InPlay seeks out and employs new technologies where possible. With the Company's extensive potential drilling opportunities and advance planning, the Company believes it can manage the slower pace of regulatory approvals and the requirements for extensive landowner consultation.

The Company has a formal emergency response plan which details the procedures employees and contractors will follow in the event of an operational emergency. The emergency response plan is designed to respond to emergencies in an organized and timely manner so that the safety of employees, contractors, residents in the vicinity of field operations, the general public and the environment are protected. A corporate safety program covers hazard identification and control on the jobsite, establishes Company policies, rules and work procedures and outlines training requirements for employees and contract personnel.

The Company currently deals with a small number of buyers and sales contracts, and endeavors to ensure that those buyers are an appropriate credit risk. The Company continuously evaluates the merits of entering into fixed price or financial hedge contracts for price management.

The oil and natural gas business is subject to regulation and intervention by governments in such matters as the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to prices, taxes, royalties, transportation and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas, increase the Company's costs, impact the Company's ability to get its product to market, or affect its future opportunities. Over the last year, the Alberta provincial government has published its Royalty Review Advisory Panel Report. The details for implementing the recommendations have yet to be announced.

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and natural gas industry operations. Such legislation may also impose restrictions and prohibitions on water use or processing in connection with certain oil and natural gas operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in, amongst other things, suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

OUTLOOK

The InPlay team has put together a premier light, oil-weighted asset base highlighted by large oil in place, low decline, long-reserve life and a large inventory of high rate of return drilling locations. Capital expenditures for 2017 are forecasted to be approximately $48.2 million, comprised of $32.9 million in exploration and development capital, $14.1 in crown land sale acquisitions and $1.2 million in net property acquisitions, which will encompass a 10.1 net well drilling program of which 4.0 net wells are to be drilled post third quarter 2017, including a 3 well pad in Willesden Green and our first Duvernay exploration well.

SELECTED QUARTERLY INFORMATION

The following table provides financial and operating results for the last eight quarters. Commodity prices remain volatile, affecting adjusted funds flow from operations and profit (loss) throughout those quarters.

The dramatic decrease in commodity prices late in 2015 and early 2016 led to a significant decrease in revenues, cash from operating activities, and adjusted funds flow from operations for the first three quarters of 2016. The impact of lower commodity prices also led to a recognition of impairment losses of $25.1 million and $13.1 million in the third quarter and fourth quarter of 2015 respectively, and an impairment loss of $12.2 million in the second quarter of 2016.

In the third quarter of 2015, the Company drilled 5.0 net horizontal wells, two of which were completed in August, 2015 and three in October, 2015.

InPlay continued its development activity in the second quarter of 2016 drilling, completing and equipping 2.0 (1.73 net) Belly River horizontal wells.

In the fourth quarter of 2016 In Play successfully completed a private placement financing raising $70.3 million, closed on an asset acquisition in its core Pembina area and completed a plan of arrangement with Anderson Energy Inc. which resulted in InPlay becoming publicly listed on the Toronto Stock Exchange. The Arrangement and Asset Acquisition were treated as business combinations in the quarter. 4.0 (3.9 net) horizontal wells were drilled in the quarter.

In the first quarter of 2017, 7.0 (5.1 net) wells were drilled of which 1.0 (1.0 net) were awaiting completion and tie in at the end of the quarter. The drilling, completion and equipping program continued into the second quarter of 2017 with the completion of 2.0 gross (1.8 net) wells drilled in the first quarter and starting the drilling of 1.0 gross (1.0 net) well which was completed in the third quarter, in addition to an asset acquisition which closed on June 6, 2017.

After the end of the third quarter, an additional 3.0 (3.0 net) wells were drilled and are currently being completed.

SELECTED QUARTERLY INFORMATION

($ amounts in thousands, except per share amounts)	**Q3 2017**	Q2 2017	Q1 2017	Q4 2016
Oil and natural gas sales	**14,489**	14,584	15,149	10,578
Oil and natural gas sales, net of royalties	**12,980**	13,171	13,566	9,642
Profit (loss)	**(2,228)**	457	1,010	36,077
Profit (loss) per share, basic and diluted(3)	**(0.04)**	0.01	0.02	0.86
Cash from operating activities	**3,659**	6,431	6,000	845
Adjusted funds flow from operations(2)	**4,662**	6,171	6,096	35
Adj. funds flow from operations per share, basic and diluted(3)	**0.08**	0.10	0.10	0.00
Net debt(2)	**41,950**	37,960	37,987	34,557

	Q3 2016	Q2 2016	Q1 2016	Q4 2015
Oil and natural gas sales	5,681	6,377	5,213	7,655
Oil and natural gas sales, net of royalties	5,150	5,874	4,716	6,941
(Loss)(1)	(1,538)	(11,691)	(2,829)	(9,862)
(Loss) per share, basic and diluted(3)	(0.13)	(0.97)	(0.23)	(0.82)
Cash from (used in) operating activities	(1,527)	2,919	3,063	4,513
Adjusted funds flow from operations(2)	1,386	2,177	2,928	4,701
Adj. funds flow from operations per share, basic and diluted(3)	0.11	0.18	0.24	0.39
Net debt(2)	56,564	57,643	59,263	59,159

(1) See note 22 of the audited December 31, 2015 financial statements regarding the reclassification between Oil and Gas sales and Transportation expense. This reclassification has nil impact on both net income and adjusted funds flow from operations.

(2) "Working capital (deficit)", "Net debt" and "Adjusted funds flow from operations" are not recognized under GAAP. Please refer to the "Non-GAAP Measures" section in this Management's Discussion and Analysis for the description and definition of these Non GAAP Measures.

(3) All weighted average share amounts are converted retrospectively at the exchange rate of 0.1303 in accordance with the terms of the Arrangement as outlined in note 5 & 11 in the unaudited quarterly September 30, 2017 financial statements. This is done in accordance with IAS 33.64.

SELECTED ANNUAL INFORMATION

Years ended December 31 (in thousands, except per share amounts)	2016	2015	2014
Total oil and natural gas sales(1)	27,850	32,556	16,960
Oil and natural gas sales, net of royalties(1)	25,382	29,572	14,142
Earnings (loss)	20,019	(30,101)	(38,646)
Earnings (loss) per share, basic and diluted	1.02	(2.50)	(5.20)
Total assets	303,409	143,327	161,242
Total bank loans	29,755	57,901	39,475
Total net debt(2)	34,557	59,159	52,225

(1) Includes royalty and other income classified with oil and natural gas sales. The oil and natural gas sales exclude realized and unrealized gains and (losses) on risk management derivative contracts: 2016 excludes $2.7 million realized gain and ($4.8) million unrealized loss; 2015 - $3.9 million realized gain and $3.2 million unrealized gain; and 2014 - $nil realized gain and $nil unrealized gain.

(2) Net debt is considered a non-GAAP measure. Refer to "Net debt" in the section entitled "Non-GAAP Measures" at the end of this MD&A.

ADDITIONAL INFORMATION

Additional information regarding InPlay and its business and operation, including its most recently filed annual information form, is available on the Company's profile on SEDAR at www.sedar.com. Certain information is also available on the Company's website at www.inplayoil.com.

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

Production volumes and reserves are commonly expressed on a BOE basis whereby natural gas volumes are converted at the ratio of 6 thousand cubic feet to 1 barrel of oil. Although the intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants, BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In recent years, the value ratio based on the price of crude oil as compared to natural gas has been significantly higher than the energy equivalency of 6:1, and utilizing a conversion of natural gas volumes on a 6:1 basis may be misleading as an indication of value.

Short-term production rates can be influenced by flush production effects from fracture stimulations in horizontal wellbores and may not be indicative of longer-term production performance or reserves. Individual well performance may vary.

NON-GAAP MEASURES

Included in this document are references to the terms "adjusted funds flow from operations", "adjusted funds flow from operations per BOE", "operating netback," "operating netback per share" and "net debt". Management believes these measures are helpful supplementary measures of financial and operating performance and provide users with similar, but potentially not comparable, information that is commonly used by other oil and natural gas companies. These terms do not have any standardized meaning prescribed by GAAP and should not be considered an alternative to, or more meaningful than, "net cash flow provided by operating activities", "funds flow from operations", "profit (loss) before taxes" or "profit (loss) and comprehensive profit (loss)", or assets and liabilities as determined in accordance with GAAP as a measure of the Company's performance and financial position.

Operating netback is calculated as oil and natural gas sales plus applicable realized gains/losses on derivative contracts less royalties, operating expenses and transportation expenses and is a measure of the profitability of operations before administrative, share-based compensation, financing and other non-cash items. Management considers operating netback an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices.

Net debt is calculated as the amount of outstanding bank loans plus current assets plus current liabilities, less the impact of derivative contracts, deferred lease payments and flow-through share premiums. See note 18 to the Company's unaudited financial statements for the six months ended September 30, 2017 and September 30, 2016. InPlay monitors working capital and net debt as part of its capital structure. Such terms do not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable with the calculation of similar measures for other entities.

InPlay considers adjusted funds flow from operations to be an important measure of InPlay's ability to generate the funds necessary to finance capital expenditures. Adjusted funds flow from operations should not be considered as an alternative to or more meaningful than net cash flow from operating activities as determined in accordance with GAAP as an indicator of the Company's performance. InPlay's determination of adjusted funds flow from operations may not be comparable to that reported by other companies. All references to adjusted funds flow from operations throughout this MD&A are calculated as net cash flow provided by operating activities adjusting for the impact of operating net change in non-cash working capital and decommissioning expenditures. These items are adjusted from net cash flow provided by operating activities as there is uncertainty with the timing, collection and payment of these items and decommissioning expenditures are incurred on a discretionary and irregular basis, making the exclusion of these items relevant in Management's view to the reader in the evaluation of InPlay's operating performance.

A reconciliation of net cash flow provided by operating activities to adjusted funds flow from operations is as follows:

	Three months ended September 30		Nine months ended September 30	
(thousands of dollars)	**2017**	2016	**2017**	2016
Net cash flow provided by (used in) operating activities	**3,659**	(1,527)	**16,091**	4,455
Net change in operating non-cash working capital	**(1,003)**	(2,858)	**(588)**	(1,981)
Decommissioning expenditures	**-**	(55)	**(251)**	(55)
Adjusted funds flow from operations	**4,662**	1,386	**16,930**	6,491

FORWARD-LOOKING STATEMENTS

This MD&A contains certain forward-looking statements and forward-looking information (collectively referred to herein as "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of present or historical fact are forward-looking statements. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "believe", "plan", "intend", "objective", "continuous", "ongoing", "estimate", "expect", "may", "will", "project", "should", or similar words suggesting future outcomes. In particular, this MD&A contains forward-looking statements relating, but not limited, to:

- drilling and development plans, and the timing thereof including incurring qualifying exploration and development expenditures related to the flow-through shares issued in 2016, and the timing thereof;
- plans to pursue additional land and acquisitions;
- InPlay's business strategy, goals and management focus;
- sources of funds for the Company's operations, capital expenditures and decommissioning obligations;
- future liquidity and the Company's access to sufficient debt and equity capital;
- anticipated completion of the non-brokered private placement and amount and timing thereof;
- InPlay's asset base and future prospects for development and growth;
- expectations regarding the business environment, industry conditions and future commodity prices;
- expectations regarding InPlay's 2017 forecasted capital expenditures, production and future operating costs;
- expectations regarding InPlay's tax horizon;
- expectations regarding InPlay's Credit Facility and capital management strategies;
- the timing and impact of new accounting policies and standards; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

Forward-looking statements regarding InPlay are based on certain key expectations and assumptions of InPlay concerning anticipated financial performance, business prospects, strategies, regulatory developments, current commodity prices and exchange rates, applicable royalty rates, tax laws, future well production rates and reserve volumes, future operating costs, the performance of existing wells, the success of its exploration and development activities, the sufficiency and timing of budgeted capital expenditures in carrying out planned activities, the availability and cost of labor and services, the impact of increasing competition, conditions in general economic and financial markets, availability of drilling and related equipment effects of regulation by governmental agencies, the ability to obtain financing on acceptable terms which are subject to change based on commodity prices, market conditions, drilling success and potential timing delays.

These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond InPlay's control. Such risks and uncertainties include, without limitation: the impact of general economic conditions; volatility in market prices for crude oil and natural gas; industry conditions; currency fluctuations; imprecision of reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition from other producers; the lack of availability of qualified personnel, drilling rigs or other services; changes in income tax laws or changes in royalty rates and incentive programs relating to the oil and natural gas industry; hazards such as fire, explosion, blowouts, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; and ability to access sufficient capital from internal and external sources.

Management has included the above summary of assumptions and risks related to forward-looking statements provided in this MD&A in order to provide readers with a more complete perspective on InPlay's future operations and such information may not be appropriate for other purposes. InPlay's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that InPlay will derive there from. Readers are cautioned that the foregoing lists of factors are not exhaustive. These forward-looking statements are made as of the date of this MD&A and InPlay disclaims any intent or obligation to update publicly any forward looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws. Additional information on these and other factors that could affect Anderson'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 at InPlay's website (www.inplayoil.com).

ABBREVIATIONS USED

bbl	barrel	AECO	intra-Alberta Nova inventory transfer price
bpd	barrels per day	GJ	gigajoule
BOE	barrel of oil equivalent	Mcf	thousand cubic feet
BOED	barrels of oil equivalent per day	Mcfd	thousand cubic feet per day
BOPD	barrels of oil per day	MMBtu	million British thermal units
Mbbls	thousand barrels	MMcf	million cubic feet
MBOE	thousand barrels of oil equivalent	MMcfd	million cubic feet per day
MMBOE	million barrels of oil equivalent	Bcf	billion cubic feet
Mstb	thousand stock tank barrels	NGL	natural gas liquids
m3	cubic metres	Cdn	Canadian
WTI	West Texas Intermediate	US	United States