Management's Discussion and Analysis

For the three and nine months ended September 30, 2019

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2019 AND SEPTEMBER 30, 2018

The following management's discussion and analysis ("**MD&A**") is dated November 6, 2019 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, 2019 and September 30, 2018. 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. The plan is based on acquiring low decline, high operating netback producing properties with drilling development 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.**". At that time, InPlay had the same directors and management as Prior InPlay. Effective November 10, 2016, 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.

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**").

REVIEW OF FINANCIAL RESULTS

Production

Average production volumes for the three and nine month periods ended September 30, 2019 and September 30, 2018 were as follows:

	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Crude oil (bpd)	**2,580**	2,775	**2,680**	2,695
NGL (bpd)	**748**	541	**639**	465
Natural gas (Mcfd)	**10,509**	8,738	**10,085**	8,218
Total (BOED)(1)	**5,080**	4,773	**5,000**	4,529

(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 three and nine months ended September 30, 2019 was 6% higher and 10% higher respectively (light crude oil and liquids; no change for the three month period and 5% higher for the nine month period) than the same periods in 2018, primarily as a result of the added volumes from the drilling programs during 2018 and continuing into 2019. These increases were realized despite the October 1, 2018 disposal of assets producing approximately 250 boe/d.

InPlay's 2019 capital program to date has consisted of $27.5 million of development capital focused in the Willesden Green and Pembina Cardium areas. The Company drilled 10 (5.2 net) extended reach horizontal ("ERH") wells and three (3.0 net) one-mile horizontal wells during the nine months ended September 30, 2019, amounting to an equivalent of 22 gross horizontal miles (11.8 net horizontal miles) and completed two (2.0 net) ERH wells that were drilled in the fourth quarter of 2018. The three (3.0 net) Pembina wells that were drilled in the third quarter of 2019 were completed and brought on production in October.

Crude oil and natural gas sales

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Crude oil	**15,582**	19,709	**49,051**	55,139
NGLs	**1,005**	2,101	**3,468**	5,239
Natural gas	**808**	991	**4,081**	3,325
Total crude oil and natural gas sales	**17,395**	22,801	**56,600**	63,703

Realized Prices

	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Crude oil ($/bbl)	**65.64**	77.20	**67.03**	74.96
NGLs ($/boe)	**14.60**	42.18	**19.89**	41.28
Natural gas ($/Mcf)	**0.84**	1.23	**1.48**	1.48
Total ($/boe)	**37.22**	51.93	**41.47**	51.52

Crude oil benchmark prices decreased in the three and nine months ended September 30, 2019 compared to average prices during the same periods in 2018. In the third quarter of 2019, WTI oil prices decreased 19% averaging $56.45 US per bbl compared to $69.46 US per bbl in the third quarter of 2018. In the nine months ended September 30, 2019, WTI oil prices decreased 15% averaging $57.06 US per bbl compared to $66.74 US per bbl in the same period in 2018.

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 pipeline capacity, refinery turnarounds, rail capacity and market supply/demand conditions.

These differentials returned to more historically normal levels during the first quarter of 2019. Monthly index differentials averaged $4.66 US per barrel discount for the third quarter of 2019 compared to $6.83 US per barrel discount for the third quarter of 2018. Monthly index differentials averaged $4.71 US per barrel discount for the first nine months of 2019 compared to $6.06 US per barrel discount for the first nine months of 2018.

Natural gas and certain NGL benchmark prices were at or near all-time lows during the third quarter of 2019, with natural gas AECO daily index prices averaging $0.82 per mcf compared to $1.07 per mcf during the third quarter of 2018.

Realized oil prices are adjusted for the Canada/US exchange rate which decreased averaging 0.76 for the third quarter of 2019 compared to 0.77 for the third quarter of 2018. The Canada/US exchange rate also decreased to 0.75 from 0.78 over the first nine months of 2019 compared to the same period in 2018.

Third quarter 2019 realized prices decreased compared to the third quarter of 2018. The Company's average price for crude oil was $65.64 per bbl for the quarter ended September 30, 2019, 15% lower than the third quarter of 2018 price of $77.20 per bbl. The Company's average realized NGL sales price was $14.60 per boe for the three months ended September 30, 2019, 65% lower than the third quarter of 2018 price of $42.18 per boe as a result of significant reductions in butane and propane prices due to excess supply in the market. The Company's average realized natural gas sales price was $0.84 per Mcf for the three months ended September 30, 2019, 32% lower than the third quarter of 2018 price of $1.23 per Mcf.

Realized oil prices for the first nine months of 2019 also decreased compared to the same period in 2018. The Company's average price for crude oil was $67.03 per bbl for the nine months ended September 30, 2019, 11% lower than the first nine months of 2018 price of $74.96 per bbl. The Company's average realized NGL sales price was $19.89 per boe for the nine months ended September 30, 2019, 52% lower than the first nine months of 2018 price of $41.28 per boe as a result of the reduced NGL prices received in the second and third quarter of 2019. Realized natural gas prices remained flat over the two respective periods at $1.48 per Mcf for both the nine months ended September 30, 2019 and the nine months ended September 30, 2018.

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 this period, 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 commodity prices and adjustments to gas cost allowance. Thus, 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	
	2019	2018	**2019**	2018
Total royalties ($'000s)	**1,658**	2,648	**4,759**	6,884
Total royalties (% of sales)	**9.5%**	11.6%	**8.4%**	10.8%
Total royalties ($/BOE)	**3.55**	6.03	**3.49**	5.57

Lower posted par prices by the government of Alberta in the first nine months of 2019 in comparison to the first nine months of 2018 and increased Crown gas cost allowance credits from additional third party custom processing fees resulted in lower royalty rates as a percentage of revenue and on a per boe basis, with posted par prices beginning to increase in the third quarter of 2019.

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 enter into commodity derivative contracts in order to 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, 2019 the Company did not have any commodity-based derivative contracts outstanding.

The statements of (loss) and comprehensive (loss) for the three and nine months ended September 30, 2019 reflected the following gains/(losses) related to derivative contracts that were outstanding during these periods and the comparative periods for 2018:

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Realized gain (loss)	**-**	(767)	**22**	(3,811)
Unrealized gain (loss)	**-**	756	**(149)**	188
Total (loss) on derivative contracts	**-**	(11)	**(127)**	(3,623)

Operating expenses

	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Total operating costs ($'000s)	**6,295**	6,858	**19,133**	20,159
Total operating costs ($/BOE)	**13.47**	15.62	**14.02**	16.30

Operating costs include expenses incurred to operate 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, 2019, operating expenses decreased to $13.47 per boe compared to $15.62 per boe for the same period in 2018. For the nine months ended September 30, 2019, operating expenses decreased to $14.02 per boe compared to $16.30 per boe for the same period in 2018. Improvements in operating costs on a per boe basis reflect fixed operating costs being incurred over a larger production base, additional focus on cost reductions and improved operating efficiencies from new technology implemented on new wells drilled and brought on production during the first nine months of 2019.

Transportation expenses

	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Total transportation costs ($'000s)	**356**	338	**1,166**	949
Total transportation costs ($/BOE)	**0.76**	0.77	**0.85**	0.77

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 quarter ended September 30, 2019, transportation expenses were $0.76 per boe and were slightly lower in comparison to $0.77 per boe for the quarter ended September 30, 2018. For the nine months ended September 30, 2019, transportation expenses were $0.85 per boe and were higher in comparison to $0.77 per boe for the nine months ended September 30, 2018.

Operating Income and Netback

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Revenue(1)	**17,395**	22,801	**56,600**	63,703
Royalties	**(1,658)**	(2,648)	**(4,759)**	(6,884)
Operating expenses	**(6,295)**	(6,858)	**(19,133)**	(20,159)
Transportation expenses	**(356)**	(338)	**(1,166)**	(949)
Operating income(2)	**9,086**	12,957	**31,542**	35,711
Sales volume (Mboe)	**467.4**	439.1	**1,365.0**	1,236.5
Per BOE				
Revenue	**37.22**	51.93	**41.47**	51.52
Royalties	**(3.55)**	(6.03)	**(3.49)**	(5.57)
Operating expenses	**(13.47)**	(15.62)	**(14.02)**	(16.30)
Transportation expenses	**(0.76)**	(0.77)	**(0.85)**	(0.77)
Operating netback per BOE(2)	**19.44**	29.51	**23.11**	28.88
Operating income profit margin(2)	**52%**	57%	**56%**	56%

(1) Includes royalty and other income classified with oil and natural gas sales.

(2) Operating income, operating netback per BOE and operating income profit margin are non-GAAP measures and therefore may not be comparable with the calculations of similar measures for other companies. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

Operating income and operating netback per boe were lower for the third quarter and first nine months of 2019 compared to the same periods in 2018 largely due to lower revenue resulting from decreased benchmark commodity prices. Tracking the 20% decrease in realized prices over the nine month period ended September 30, 2019 compared to the same period in 2018, the Company's operating netback also decreased by 20% and operating income profit margins remained relatively flat, primarily due to operational efficiencies and lower royalty rates during the nine months ended September 30, 2019.

General and administrative expenses

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

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Gross G&A expenditures	**1,966**	1,950	**6,242**	5,964
Capitalized and recoveries	**(407)**	(417)	**(1,305)**	(1,201)
General and administrative expenses	**1,559**	1,533	**4,937**	4,763
G&A expenses ($/BOE)	**3.34**	3.49	**3.62**	3.85
% Capitalized and recoveries	**21%**	21%	**21%**	20%

For the quarter ended September 30, 2019, G&A expenses were $1.6 million ($3.34 per boe) compared to $1.5 million ($3.49 per boe) for the quarter ended September 30, 2018. For the nine months ended September 30, 2019, G&A expenses were $4.9 million ($3.62 per boe) compared to $4.8 million ($3.85 per boe) for the nine months ended September 30, 2018.

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 and comprehensive income.

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Share-based compensation	**309**	429	**769**	1,142
Capitalized portion	**(71)**	(136)	**(171)**	(361)
Share-based compensation expense	**238**	293	**598**	781

During the nine months ended September 30, 2019, 217,500 options were granted. During the quarter ended September 30, 2019, 4,259,400 stock options were surrendered and cancelled, resulting in the recognition of $0.1 million in share based compensation expense. At September 30, 2019, the maximum number of stock options available for grant was 6,825,662.

Depletion and depreciation

	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Depletion and depreciation ($'000s)	**7,606**	7,210	**21,977**	19,973
Depletion and depreciation ($/BOE)	**16.27**	16.42	**16.10**	16.15

The carrying costs for property, plant and equipment directly associated with crude oil and natural gas operations, including estimated future development costs, are recognized as depletion expense in the statements of (loss) and comprehensive (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 (loss) and comprehensive (loss) on a straight-line or declining-balance basis.

Depletion and depreciation was $7.6 million ($16.27 per boe) for the quarter ended September 30, 2019 compared to $7.2 million ($16.42 per boe) in the third quarter of 2018. Depletion and depreciation was $22.0 million ($16.10 per boe) for the nine months ended September 30, 2019 compared to $20.0 million ($16.15 per boe) in the first nine months of 2018.

Impairment

Management identified indicators of impairment at September 30, 2019 for two of its CGU's including declines in natural gas and liquids pricing since the last impairment test was performed. Impairment tests were performed for the Company's Pigeon Lake and Minors/Red Deer CGUs which did not result in an impairment loss being recorded in the Company's statement of (loss) and comprehensive (loss). The Company used the income approach technique to measure fair value of the CGUs whereby the net present value of the future cash flows were calculated using a discount rate of 12%. The future cash flows were based on level 3 fair value hierarchy inputs: the Company's reserves prepared by its independent reserves evaluator as at December 31, 2018, including key assumptions regarding the discount rate, quantities of reserves and production volumes, future commodity prices as prepared by its independent reserves evaluator, royalty obligations, operating expenses, development costs, and decommissioning costs. The Company's reserves prepared by its independent reserves evaluator as at December 31, 2018 have been updated by internal qualified reserve engineers to September 30, 2019.

Finance expenses

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Interest expense (Credit Facility[1] and other)	**637**	651	**1,920**	1,789
Interest expense (Lease liabilities)	**4**	-	**13**	-
Accretion on decommissioning obligation	**278**	421	**902**	1,185
Finance expense	**919**	1,072	**2,835**	2,974

(1) Please refer to the "Liquidity and Capital Resources" section in this Management's Discussion and Analysis for the description of the Credit Facility.

Finance expenses were $0.9 million for the third quarter of 2019, compared to $1.1 million in the third quarter of 2018. Finance expenses were $2.8 million for the first nine months of 2019, compared to $3.0 million in the first nine months of 2018. Interest expense in the third quarter and first nine months of 2019 is determined in accordance with the Company's Credit Facility.

Income taxes

The Company has recognized a deferred tax asset in the amount of $48.6 million at September 30, 2019.

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.

During the quarter ended June 30, 2019, the Alberta corporate tax rate decreased from 12% to 8%. The tax rate decrease will be phased in as follows: 11% effective July 1, 2019, 10% effective January 1, 2020, 9% effective January 1, 2021, and 8% effective January 1, 2022. This rate change results in decreased future value attributable to the Company's unused tax losses and temporary differences. As a result, the Company has recognized a reduction to its deferred tax asset and a deferred income tax expense of $8.5 million during the nine months ended September 30, 2019.

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at September 30, 2019.

Non-capital loss carryforward balances	$	81,729
Share issue costs		1,529
Canadian Exploration Expenses (CEE)		64,773
Canadian Development Expenses (CDE)		71,673
Canadian Oil and Gas Property Expenses (COGPE)		124,239
Undepreciated Capital Cost (UCC)		50,246
Total	$	394,189

FUNDS FLOW AND ADJUSTED FUNDS FLOW

Management considers adjusted funds flow to be a key measure of operating performance as it demonstrates the Company's ability to generate the funds necessary to finance capital expenditures. Management believes that by excluding decommissioning expenditures, adjusted funds flow provides a useful measure of the Company's ability to generate cash that is not subject to non-recurring decommissioning expenditures. Adjusted funds flow is not a recognized measure under GAAP and therefore may not be comparable with the calculation of similar measures by other entities.

The Company reports adjusted funds flow in total and on a per share basis. The following table reconciles funds flow to adjusted funds flow:

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Funds flow	**6,397**	9,962	**23,391**	24,360
Decommissioning expenditures	**489**	44	**1,303**	960
Adjusted funds flow[(1)]	**6,886**	10,006	**24,694**	25,320

(1) "Adjusted funds flow" is not a recognized measure under GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

Funds flow for the three and nine months ended September 30, 2019, was $6.4 million and $23.4 million, respectively, compared to $10.0 million and $24.4 million for the same periods in 2018. Adjusted funds flow for the three and nine months ended September 30, 2019, was $6.9 million and $24.7 million, respectively, compared to $10.0 million and $25.3 million for the same periods in 2018. These changes are impacted by the significant benchmark pricing decreases during the respective periods.

CAPITAL EXPENDITURES

Capital expenditures for the three and nine months ended September 30, 2019 were $8.1 million and $27.5 million, respectively. The breakdown of capital expenditures is shown below:

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Land and lease	**16**	30	**69**	1,558
Drilling, completions & re-entries	**6,792**	15,073	**21,066**	35,229
Facilities and equipping costs	**935**	1,947	**5,226**	5,451
Total exploration and development capital	**7,743**	17,050	**26,361**	42,238
Office & Capitalized G&A	**339**	326	**1,172**	1,014
Total	**8,082**	17,376	**27,533**	43,252
Net Property Acquisitions/(Dispositions)[(1)]	**-**	(26)	**78**	(4,164)
Total capital expenditures	**8,082**	17,350	**27,611**	39,088

(1) Property Acquisitions/(Dispositions) capital amounts to the total amount of cash and share consideration net of any working capital balances assumed with an acquisition on closing.

InPlay's 2019 capital program to date has consisted of $27.5 million of development capital focused in the Willesden Green and Pembina Cardium areas. The Company drilled 10 (5.2 net) extended reach horizontal ("ERH") wells and three (3.0 net) one-mile horizontal wells during the nine months ended September 30, 2019, amounting to an equivalent of 22 gross horizontal miles (11.8 net horizontal miles) and completed two (2.0 net) ERH wells that were drilled in the fourth quarter of 2018. The three (3.0 net) Pembina wells that were drilled in the third quarter of 2019 were completed and brought on production in October.

Drilling statistics are shown below:

	Three months ended September 30				Nine months ended September 30			
	2019		2018		**2019**		2018	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**6.0**	**3.5**	5.0	3.3	**13.0**	**8.2**	13.0	9.1
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**6.0**	**3.5**	5.0	3.3	**13.0**	**8.2**	13.0	9.1
Success rate	**100%**	**100%**	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 6, 2019, there were 68,256,616 common shares outstanding and 2,142,600 stock options that, subject to vesting, are convertible into, or exercisable or exchangeable for, an equivalent number of common shares of the Company.

RELATED PARTY TRANSACTIONS

InPlay had no related party transactions that were entered into under the normal course of business for the three and nine months ended September 30, 2019 or September 30, 2018.

LIQUIDITY AND CAPITAL RESOURCES

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

At September 30, 2019, the Company has a syndicated $75 million senior secured revolving credit facility (the "**Credit Facility**"). The Credit Facility consists of a $65 million revolving line of credit and a $10 million operating line of credit. The Credit Facility has a term date of May 31, 2020, and, if not extended, additional advances would not be permitted and any outstanding advances would become repayable one year later on May 31, 2021. The Credit Facility is secured by a floating charge debenture and a general security agreement on the assets of the Company. At September 30, 2019 the Company had drawn $52.0 million on the Credit Facility. The available lending limit of the Credit Facility is scheduled for semi-annual review on or before November 30, 2019 and is based on the Lenders' interpretation of the Company's reserves and future commodity prices. In addition, a provision has been put in place until the next semi-annual review on November 30, 2019 in which the borrowing base may be redetermined if requested by any lender in the event the outstanding principal under the Credit Facility exceeds $60 million. 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 reduce 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. There are standard reporting covenants under the Credit Facility however there are no financial covenants. The Company was in compliance with these standard reporting covenants as at September 30, 2019.

In addition, at September 30, 2019 the Company had a current asset to accounts payable and accrued liabilities deficit of ($6.0) million. The Company expected to have a higher level of working capital (deficit) due to the increased amounts of accounts payable and accrued liabilities related to the active drilling program during the first nine months of 2019.

The Company's Net debt/annualized adjusted funds flow(1) ratio of 2.1x for the quarter ended September 30, 2019 increased from 1.6x for the quarter ended September 30, 2018 given the impact of decreased realized prices on adjusted funds flow for the three months ended September 30, 2019.

(1) Net debt/annualized adjusted funds flow is a non-GAAP measure and therefore may not be comparable with the calculations of similar measures for other companies. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

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, 2019, these obligations include:

- **Loan agreement** – The reserves-based, extendable, committed-term Credit Facility has a term date of May 31, 2020. If not extended, any outstanding advances would become repayable on May 31, 2021. Refer to the 'Liquidity and Capital Resources' section for more information.
- **Firm service transportation commitments** – The Company has entered into firm service transportation agreements. Fees related to transportation periods subsequent to September 30, 2019 were not recognized as a liability as at September 30, 2019.

As at September 30, 2019 the Company had the following minimum contractual obligations:

Contractual obligations	Payments due by year					
(in thousands of dollars)	2019	2020	2021	2022	2023	Thereafter
Accounts payable	17,676	-	-	-	-	-
Bank debt - principal(1)	-	-	52,012	-	-	-
Bank debt - interest(2)	624	2,496	1,040	-	-	-
Non-cancellable office leases	103	411	411	34	-	-
Other leases	69	120	53	16	-	-
Firm service(3)	143	227	70	44	42	96
Total	18,615	3,254	53,586	94	42	96

(1) Assumes the Credit Facility is not renewed as of May 31, 2020, and the entire outstanding balance becomes payable on May 31, 2021.

(2) Assumes interest is incurred on bank debt outstanding at September 30, 2019 at the Company's effective interest rate during the quarter and the principal balance is repaid on May 31, 2021.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is a plaintiff or defendant in various legal actions and other disputes arising from time to time 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 Company's unaudited interim financial statements for the three months ended September 30, 2019. 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 4 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.

CHANGES IN ACCOUNTING POLICIES

There were no new or amended accounting standards or interpretations adopted in the nine months ended September 30, 2019, other than the following:

IFRS 16 "Leases". Effective January 1, 2019, the Company has adopted IFRS 16, "Leases" ("IFRS 16"). The Company has applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Therefore, the comparative information in the Company's statement of financial position, statements of profit and comprehensive income, changes in equity and cash flows have not been restated.

On adoption, the Company elected to use the following practical expedients permitted under IFRS 16:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for leases with a remaining term of less than twelve months as at January 1, 2019 as short term leases; and
- Account for lease payments as an expense and not recognize a right-of-use asset if the leased asset is of a low dollar value (less than US$5,000).

On adoption of IFRS 16, the Company recognized lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "Leases" ("IAS 17"). Under the principles of the new standard, these leases have been measured at the present value of the remaining lease payments, discounted using the discount rate implicit in the lease or the Company's incremental borrowing rate as at January 1, 2019. The Company's incremental borrowing rate as at January 1, 2019 was approximately 5.0 percent. Leases with a remaining term of less than twelve months and low-value leases were excluded. Total lease liabilities of $0.4 million were recorded as at January 1, 2019.

The associated right-of-use asset was measured in an amount equal to the corresponding lease liability. A right-of-use asset of $0.4 million has been recognized at January 1, 2019.

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 1, 2019 and ended on September 30, 2019 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 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 number of years, 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 additional risks are described in more detail in the Company's most recent AIF filed with 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.

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

InPlay continues to outperform operationally with production from our drilling results to date exceeding our internal forecasted type curves. Given the strong results achieved year to date, the Company is on pace to achieve its annual average production guidance without drilling any additional wells. Accordingly, InPlay does not plan to drill any additional wells in 2019 thereby reducing its annual capital budget by 11% to $32 million (from $36 million).

The three 100% Pembina wells which were placed on production the third week of October are currently meeting expectations and are still in an early clean up stage. Over the first seventeen days of production they are averaging 183 boed (96% light oil) per well. More importantly are the capital efficiencies being achieved at Pembina as we transferred our refined completion operations from Willesden Green and are also utilizing fundamentally refined changes in drilling and equipping practices in Pembina. This has resulted in costs to drill, complete, equip and tie-in these wells of approximately $1.8 million per well compared to the $2.4 million we previously spent on a drilling operation in Pembina two years ago. InPlay believes the encouraging initial production results combined with the 25% reduction in capital costs makes Pembina development economically competitive with its industry leading Willesden Green economics.

The Company has achieved its exit production guidance of 5,500 – 5,700 boe/d (67 - 70% light oil and liquids) early as current production, based on field estimates, is approximately 5,560 boe/d (66% light oil and liquids).

InPlay now plans to drill 8.2 net horizontal wells in 2019 compared to the 9.0 – 10.0 net horizontal wells originally forecasted. This results in an 11% reduction in total forecasted 2019 capital expenditures to approximately $32 million compared to our previous forecast of $36 million and production is anticipated to be in the lower half of our annual average production guidance of 5,000 – 5,200 boe/d (66% - 70% light oil and liquids) generating annual average production growth of between 8% - 10%. This program is forecast to result in 2019 AFF of $31 - $34 million in line with total capital expenditures. These results are anticipated to result in top tier organic light oil and liquids growth among our light oil peers for 2019.

Volatility in commodity prices continues into the fourth quarter of 2019 with forward WTI prices fluctuating between US$54.00/bbl and US$57.00/bbl with a strong improvement in AECO pricing ranging between $2.25 - $3.00/Mcf. Edmonton light sweet differentials had returned to historically normal levels over the first nine months of 2019 and started the fourth quarter between a $4.00 - $4.50 USD/bbl discount to WTI but has currently increased to over an $8.00 USD/bbl discount to WTI for December of 2019 with the current shut-in of the Keystone XL pipeline. InPlay continues to forecast depressed NGL pricing for the remainder of 2019, however we expect to see improved prices in the new year.

InPlay's strategy is to leverage management's strong technical and operational capabilities to deliver top tier production growth, capital efficiencies and returns relative to our light oil peers. We are focused on running a sustainable junior oil company with a long term view to ensure we maintain a strong financial position during volatile commodity prices and during periods with limited access to capital. InPlay has reacted to these market factors as we see widening differentials into year-end by reducing development capital while still providing 8 – 10% production growth over 2018. Our financial and operational flexibility will allow us to react quickly and expand activity as market factors improve.

SELECTED QUARTERLY INFORMATION

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

SELECTED QUARTERLY INFORMATION

($ amounts in thousands, except per share amounts)	**Q3 2019**	Q2 2019	Q1 2019	Q4 2018
Oil and natural gas sales	**17,395**	19,995	19,210	12,716
Oil and natural gas sales, net of royalties	**15,737**	18,386	17,718	11,591
Profit (loss)	**(1,355)**	(7,629)	1,035	(7,887)
Profit (loss) per share, basic and diluted	**(0.02)**	(0.11)	0.02	(0.12)
Exploration and development capital expenditures	**8,082**	4,688	14,763	6,954
Property acquisitions/(dispositions)	**-**	(9)	87	(17,305)
Funds flow	**6,397**	8,461	8,534	1,441
Adjusted funds flow(1)	**6,886**	8,755	9,054	1,721
Adjusted funds flow per share, basic and diluted(1)	**0.10**	0.13	0.13	0.03
Adjusted funds flow per boe(1)	**14.73**	18.58	21.24	3.73
Net debt	**58,053**	56,304	60,033	53,670

	Q3 2018	Q2 2018	Q1 2018	Q4 2017
Oil and natural gas sales	22,801	20,993	19,909	18,017
Oil and natural gas sales, net of royalties	20,153	18,748	17,919	16,255
Profit (loss)	(1,775)	(326)	1,390	(6,939)
Profit (loss) per share, basic and diluted	(0.03)	0.00	0.02	(0.11)
Exploration and development capital expenditures	17,376	12,329	13,546	26,992
Property acquisitions/(dispositions)	(26)	184	(4,321)	(152)
Funds flow	9,962	7,305	7,095	7,650
Adjusted funds flow(1)	10,006	7,376	7,939	8,043
Adjusted. funds flow per share, basic and diluted(1)	0.15	0.11	0.12	0.13
Adjusted funds flow per boe(1)	22.79	18.44	19.98	20.90
Net debt	66,005	58,616	53,407	51,266

(1) "Adjusted funds flow", "Adjusted funds flow per share, basic and diluted" and "Adjusted funds flow per boe" are not recognized measures under GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

A 3.0 (3.0 net) well pad was drilled and completed in the fourth quarter of 2017, along with the drilling of our first East Basin Duvernay Shale horizontal well (1.0 net). Flow-through common shares were issued by the Company in the fourth quarter for proceeds of $10.1 million. A total of $14.1 million was spent acquiring undeveloped land at crown land sales during the fourth quarter of 2017.

The Company's 2018 drilling program consisted of $50.2 million of capital mainly focused on the Willesden Green bioturbated Cardium where the Company drilled 12 (8.6 net) extended reach horizontal ("ERH") wells and 4 (2.6 net) one-mile horizontal wells. Completion of 2 (2.0 net) of these ERH wells was performed in January 2019. In aggregate, InPlay drilled an equivalent of 23.0 gross horizontal miles (16.5 net horizontal miles). In addition, we completed our first Duvernay horizontal well during the second quarter of 2018. One vertical stratigraphic test well was drilled in the Duvernay area in the fourth quarter extending the land tenure on this block for an additional five years. The Company also spent $1.4 million acquiring an additional 12 sections of undeveloped Crown land in the Duvernay area. The Company purchased minor producing assets which had significant associated undeveloped lands and beneficial interests in various facilities in the Willesden

Green area of Alberta, Canada for consideration of $5.5 million in the first quarter of 2018. The Company also completed the sale of a non-core processing facility and associated equipment and infrastructure for proceeds of $10.0 million during the first quarter of 2018. On October 1, 2018 the Company completed a strategic disposition of certain non-core oil and gas properties in the west Pembina area of Alberta for cash consideration of $16.6 million disposing of approximately 250 boe/d.

InPlay's 2019 capital program to date has consisted of $27.5 million of development capital focused in the Willesden Green and Pembina Cardium areas. The Company drilled 10 (5.2 net) extended reach horizontal ("ERH") wells and three (3.0 net) one-mile horizontal wells during the nine months ended September 30, 2019, amounting to an equivalent of 22 gross horizontal miles (11.8 net horizontal miles) and completed two (2.0 net) ERH wells that were drilled in the fourth quarter of 2018. The three (3.0 net) Pembina wells that were drilled in the third quarter of 2019 were completed and brought on production in October.

SELECTED ANNUAL INFORMATION

Years ended December 31

(in thousands, except per share amounts)		**2018**	2017	2016
Total oil and natural gas sales[(1)]	$	**76,419**	62,239	27,850
Oil and natural gas sales, net of royalties[(1)]		**68,410**	55,972	25,382
Earnings (loss)		**(8,598)**	(7,701)	20,019
Earnings (loss) per share, basic and diluted		**(0.13)**	(0.12)	1.02
Total assets		**314,021**	323,793	303,409
Bank debt		**45,400**	44,888	29,755
Net debt		**53,670**	51,266	34,556

(1) The oil and natural gas sales exclude realized and unrealized gains (losses) on risk management derivative contracts: 2018 excludes ($4.1) million realized loss and $1.7 million unrealized gain; 2017 excludes $1.1 million realized gain and ($0.03) million unrealized loss; and 2016 excludes $2.7 million realized gain and ($4.8) million unrealized loss.

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. This 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 ultimate recovery of reserves. Individual well performance may vary.

NON-GAAP MEASURES

Included in this document are references to the terms "adjusted funds flow", "adjusted funds flow per share, basic and diluted", "adjusted funds flow per boe", "operating income", "operating netback per boe", "operating income profit margin" and "net debt/annualized adjusted funds flow". 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, "funds flow", "profit (loss) before taxes", "profit (loss) and comprehensive income (loss)" or assets and liabilities as determined in accordance with GAAP as a measure of the Company's performance and financial position.

Adjusted Funds Flow

Management considers adjusted funds flow to be an important measure of InPlay's ability to generate the funds necessary to finance capital expenditures. Adjusted funds flow should not be considered as an alternative to or more meaningful than funds flow as determined in accordance with GAAP as an indicator of the Company's performance. InPlay's determination of adjusted funds flow may not be comparable to that reported by other companies. All references to adjusted funds flow throughout this MD&A are calculated as funds flow adjusting for decommissioning expenditures. This item is adjusted from funds flow as decommissioning expenditures are incurred on a discretionary and irregular basis and are primarily incurred on previous operating assets, making the exclusion of this item relevant in Management's view to the reader in the evaluation of InPlay's operating performance. Refer to the section entitled "Funds flow and adjusted funds flow" within this MD&A for a calculation of this measure.

Adjusted Funds Flow per Share, Basic and Diluted

Management considers adjusted funds flow per share, basic and diluted an important measure to evaluate its operational performance as it demonstrates its recurring operating cash flow generated attributable to each share. Adjusted funds flow per share, basic and diluted is calculated by the Company as adjusted funds flow divided by the weighted average number of common shares outstanding for the respective period. A calculation of adjusted funds flow per share, basic and diluted is as follows:

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Adjusted funds flow	**6,886**	10,006	**24,694**	25,320
Weighted avg. number of common shares (basic and diluted	**68,257**	67,887	**68,257**	67,887
Adjusted funds flow per share, basic and diluted	**0.10**	0.15	**0.36**	0.37

Adjusted Funds Flow per boe

Management considers adjusted funds flow per boe an important measure to evaluate its operational performance as it demonstrates its recurring operating cash flow generated per unit of production. Adjusted funds flow per boe is calculated by the Company as adjusted funds flow divided by production for the respective period. A calculation of adjusted funds flow per boe is as follows:

(thousands of dollars)	Three months ended September 30		Nine months ended September 30	
	2019	2018	**2019**	2018
Adjusted funds flow	**6,886**	10,006	**24,694**	25,320
Sales volume (Mboe)	**467.4**	439.1	**1,365.0**	1,236.5
Adjusted funds flow per boe	**14.73**	22.79	**18.09**	20.48

Operating Income

Management considers operating income an important measure to evaluate its operational performance as it demonstrates its field level profitability. Operating income should not be considered as an alternative to or more meaningful than net income as determined in accordance with GAAP as an indicator of the Company's performance. InPlay's determination of operating income may not be comparable to that reported by other companies. Operating income is calculated by the Company as oil and natural gas sales 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. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure.

Operating Netback per BOE

Management considers operating netback per boe an important measure to evaluate its operational performance as it demonstrates its field level profitability per unit of production. Operating netback per boe is calculated by the Company as operating income divided by average production for the respective period. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure.

Operating Income Profit Margin

Management considers operating income profit margin an important measure to evaluate its operational performance as it demonstrates how efficiently the Company generates field level profits from its sales revenue. Operating income profit margin is calculated by the Company as operating income as a percentage of oil and natural gas sales. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure.

Net debt/Annualized adjusted funds flow

Management considers net debt/annualized adjusted funds flow to be an important measure of InPlay's liquidity and ability to generate funds necessary to repay upcoming obligations. Net debt/annualized adjusted funds flow is calculated by the Company as net debt divided by adjusted funds flow for the current quarter multiplied by four to reflect a full annual period. A reconciliation of net debt to net debt/annualized adjusted funds flow is as follows:

(thousands of dollars)	Three months ended September 30	
	2019	2018
Net debt	**58,053**	66,005
Adjusted funds flow	**6,886**	10,006
Annualized adjusted funds flow	**27,544**	40,024
Net debt/Annualized adjusted funds flow	**2.1x**	1.6x

FORWARD-LOOKING STATEMENTS

This MD&A contains certain forward-looking statements and forward-looking information (collectively referred to herein as "**FLI**" or "**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;
- 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;
- the resource potential of 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 2019 forecasted capital expenditures, production estimates including current 2019 average and exit forecasts, future operating costs, cash flows and forecasted 2019 adjusted funds flow;
- the volume and product mix of InPlay's oil and gas production;
- targeted production growth and management's belief that it is well positioned to generate top tier returns and capital efficiencies;
- future exchange rate between the $US and $Cdn
- expectations regarding InPlay's tax horizon;
- capital management strategies;
- the timing and impact of new accounting policies and standards;
- treatment under governmental and other regulatory regimes and tax, environmental and other laws; and
- that our Pembina development has the potential to be competitive with our Willesden Green economics.

The Company has previously disclosed forecasted Q4 2019 Net debt / adjusted funds flow guidance of 1.0x. During the third quarter of 2019 the Company has elected to withdraw this FLI as this figure can fluctuate significantly given the volatility in the assumptions used to determine this measure over the course of the year, the most significant being changes to forecasted WTI prices for the remainder of the year.

The Company has previously disclosed forecasted 2019 Free cash flow guidance of $5 - $8 million. During the third quarter of 2019 the Company has elected to withdraw this FLI given the fact that pricing volatility can have such a substantial impact on Free cash flow on a percentage basis from one period to the next.

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 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 at InPlay's website (www.inplayoil.com).

The assumptions used by the Company in the development of forecasted 2019 Adjusted funds flow are as follows:

WTI	US$/bbl	$56.70
NGL Price	$/boe	$19.00
AECO	$/GJ	$1.75
Foreign Exchange rate	(US$/CDN$)	0.75
MSW Differential	US$/bbl	$5.00
Production	Boe/d	5,000 – 5,200
Royalties	$/boe	3.25 – 3.75
Operating expenses	$/boe	13.75 – 14.50
Transportation	$/boe	0.75 – 0.95
Interest	$/boe	1.25 – 1.50
General and administrative	$/boe	3.25 – 3.95
Decommissioning Expenditures	$ millions	1.1 – 1.5

- NGLs estimated to represent approximately 19% - 21% of total oil and liquids production
- Quality and pipeline transmission adjustments may impact realized oil prices in addition to the MSW Differential provided above

Forecasted full year 2019 commodity price reductions including a USD $0.50/bbl decrease in WTI and $4.00/boe decrease in realized NGL prices are the main factors causing a $2 million decrease in 2019 funds flow and adjusted funds flow from that previously forecasted.

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