Management's Discussion and Analysis

For the three and nine months ended September 30, 2020

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2020 AND SEPTEMBER 30, 2019

The following management's discussion and analysis ("**MD&A**") is dated November 12, 2020 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, 2020 and September 30, 2019 and the audited annual financial statements for the years ended December 31, 2019 and December 31, 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**").

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 months ended September 30, 2020 and September 30, 2019 were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Crude oil (bbls/d)	**1,973**	2,580	**1,976**	2,680
NGLs (boe/d)	**598**	748	**655**	639
Natural gas (Mcf/d)	**7,029**	10,509	**7,572**	10,085
Total (boe/d)[1]	**3,742**	5,080	**3,893**	5,000

(1) Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. Refer to the section entitled "Conversion Measures" at the end of this MD&A.

Production for the three and nine months ended September 30, 2020 was 26% and 22% lower respectively compared to the three and nine months ended September 30, 2019 due to the continued impacts of temporary production curtailments and shut-ins implemented by the Company in the second quarter of 2020 due to the unprecedented low commodity prices as a result of the COVID-19 pandemic. These temporary curtailments were gradually reduced late in the third quarter of 2020 as commodity prices began to improve.

InPlay's capital program for the nine months ended September 30, 2020 consisted of $12.5 million of development capital. The Company drilled one (1.0 net) extended reach horizontal ("ERH") well in Willesden Green and three (3.0 net) one-mile horizontal wells in Pembina during the first quarter of 2020, amounting to an equivalent of 4.5 gross horizontal miles (4.5 net horizontal miles). The Company also completed a water disposal facility in Pembina that will payout in less than one year and have long-term operating cost savings.

As a result of the significant drop and volatility in world crude oil prices as a result of the COVID-19 outbreak and the corresponding OPEC+ oil price war, InPlay suspended its 2020 capital program after the capital program for the first quarter of 2020 was completed. On November 2, 2020, the Company announced that it was commencing a three well capital program in the Willesden Green area in the fourth quarter of 2020.

Crude oil and natural gas sales

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Crude oil	**8,423**	15,582	**22,220**	49,051
NGLs	**921**	1,005	**2,458**	3,468
Natural gas	**1,502**	808	**4,427**	4,081
Total crude oil and natural gas sales	**10,846**	17,395	**29,105**	56,600

Prices

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Crude oil ($/bbl)	**46.41**	65.64	**41.04**	67.03
NGLs ($/boe)	**16.73**	14.60	**13.70**	19.89
Natural gas ($/Mcf)	**2.32**	0.84	**2.13**	1.48
Total ($/boe)	**31.50**	37.22	**27.29**	41.47

West Texas Intermediate ("WTI") prices decreased substantially in the three and nine months ended September 30, 2020 compared to average prices during the same periods in 2019. In the third quarter of 2020, WTI oil prices decreased 27% averaging $40.93 US per bbl compared to $56.45 US per bbl in the third quarter of 2019. In the first nine months of 2020, WTI oil prices decreased 33% averaging $38.32 US per bbl compared to $57.06 US per bbl in the first nine months of 2019 During the second half of March 2020 and into the second quarter of 2020, world oil demand destruction as a result of the COVID-19 outbreak and the corresponding OPEC+ oil price war caused WTI prices to drop to historically low levels. WTI prices began to recover in the third quarter of 2020.

Differentials between WTI oil prices and prices received in Alberta improved in the third quarter of 2020 and weakened during the first nine months of 2020 compared to the same periods in 2019. These differentials 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 apportionment, refinery turnarounds, rail capacity and market supply/demand conditions. Monthly index differentials averaged $3.51 US per barrel discount for the third quarter of 2020 compared to $4.66 US per barrel discount for the same period in 2019. Monthly index differentials averaged $5.74 US per barrel discount for the first nine months of 2020 compared to $4.71 US per barrel discount for the same period in 2019.

In the third quarter of 2020, natural gas AECO daily index prices increased 147% averaging $2.12 per GJ compared to $0.86 per GJ in the third quarter of 2019. In the first nine months of 2020, natural gas AECO daily index prices increased 38% averaging $1.98 per GJ compared to $1.44 per GJ in the first nine months of 2019.

Realized oil prices are adjusted for the Canada/US exchange rate which decreased averaging 0.75 for the third quarter of 2020 compared to 0.76 during the third quarter of 2019. The Canada/US exchange rate also decreased over the first nine months of 2020 to 0.74 compared to 0.75 over the first nine months of 2019.

Due to the items noted above, realized oil prices for the three months ended September 30, 2020 decreased significantly compared to the same period in 2019. The Company's average net realized price for crude oil was $46.41 per bbl for the quarter ended September 30, 2020, 29% lower than the third quarter 2019 price of $65.64 per bbl. Realized NGL and natural gas prices improved for the three months ended September 30, 2020 compared to the same period in 2019. The Company's average realized NGL sales price was $16.73 per boe for the third quarter of 2020, 15% higher than the third quarter of 2019 price of $14.60 per boe. The Company's average realized natural gas sales price was $2.32 per Mcf for the three months ended September 30, 2020, 176% higher than the third quarter of 2019 price of $0.84 per Mcf.

Realized oil and NGL prices for the nine months ended September 30, 2020 decreased significantly compared to the same period in 2019. The Company's average net realized price for crude oil was $41.04 per bbl for the nine months ended September 30, 2020, 39% lower than the same period in 2019 price of $67.03 per bbl. The Company's average realized NGL sales price was $13.70 per boe for the first nine months of 2020, 31% lower than the nine months of 2019 price of $19.89 per boe as a result of the continued significant reductions in butane and propane prices due to excess supply in the market. The Company's average realized natural gas sales price was $2.13 per Mcf for the nine months ended September 30, 2020, 44% higher than the first nine months of 2019 price of $1.48 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 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	
	2020	2019	**2020**	2019
Total royalties ($'000s)	**790**	1,658	**2,227**	4,759
Total royalties (% of sales)	**7.3%**	9.5%	**7.7%**	8.4%
Total royalties ($/boe)	**2.29**	3.55	**2.09**	3.49

Lower posted par prices by the government of Alberta during 2020 in comparison to 2019 resulted in lower royalty rates on a percentage of revenue and per boe basis.

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 a portion of 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, 2020 the Company had the following commodity-based derivative contracts outstanding.

Type of contract: swap (crude oil pricing WTI):

Currency denomination	Volume (bbl/day)	Average swap price	Term	Fair value ($'000s CAD)
US dollar	500	43.13/bbl	September 1, 2020 – December 31, 2020	$156
US dollar	250	43.00/bbl	September 1, 2020 – November 30, 2020	$52

Type of contract: costless collar[1] (crude oil pricing WTI):

Currency denomination	Volume (bbl/day)	Sold call price	Sold put price	Term	Fair value ($'000s CAD)
US dollar	250	34.50/bbl	50.15/bbl	January 1, 2021 – June 30, 2021	$40

(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.

Type of contract: swap (natural gas pricing AECO):

Currency denomination	Volume (GJ/day)	Average swap price	Term	Fair value ($'000s CAD)
Canadian dollar	4,000	1.61/GJ	April 1, 2020 – October 31, 2020	($76)
Canadian dollar	1,000	1.76/GJ	May 1, 2020 – October 31, 2020	($3)
Canadian dollar	1,000	2.145/GJ	June 1, 2020 – October 31, 2020	$9
Canadian dollar	2,000	2.94/GJ	November 1, 2020 – March 31, 2021	$9
Canadian dollar	2,000	2.34/GJ	January 1, 2021 – December 31, 2021	($279)

Subsequent to September 30, 2020 the Company entered into crude oil derivative contracts as follows:

Type of contract: swap (crude oil pricing WTI):

Currency denomination	Volume (bbl/day)	Average swap price	Term
US dollar	500	41.35/bbl	November 1, 2020 – December 31, 2020
US dollar	250	42.52/bbl	December 1, 2020 – June 30, 2021
US dollar	250	43.05/bbl	January 1, 2020 – March 31, 2021
US dollar	250	43.00/bbl	January 1, 2020 – June 30, 2021

The statements of (loss) and comprehensive (loss) for the three and nine months ended September 30, 2020 reflected the following gains (losses) related to derivative contracts that were outstanding during 2020 and the comparative periods for 2019.

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Realized gain (loss)	**(751)**	-	**(1,053)**	22
Unrealized gain (loss)	**393**	-	**(92)**	(149)
Total (loss) on derivative contracts	**(358)**	-	**(1,145)**	(127)

Operating expenses

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Total operating costs ($'000s)	**4,966**	6,295	**15,421**	19,133
Total operating costs ($/boe)	**14.42**	13.47	**14.46**	14.02

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. As a response to the COVID-19 pandemic, the Company implemented significant measures to reduce controllable costs which resulted in total operating costs decreasing by $1.3 million and $3.7 million, or 21% and 19%, for the three and nine months ended September 30, 2020 respectively compared to the same periods in 2019. These measures allowed the Company to incur only modest increases to operating costs per boe rates in 2020 in comparison to 2019 despite the presence of fixed operating costs being incurred over a significantly lower production base and incurring costs associated with servicing wells that were shut-in or curtailed in response to COVID-19. For the three months ended September 30, 2020, operating expenses per boe increased to $14.42 per boe compared to $13.47 per boe for the same period in 2019. For the nine months ended September 30, 2020, operating expenses also increased slightly to $14.46 per boe compared to $14.02 per boe for the same period in 2019.

Transportation expenses

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Total transportation costs ($'000s)	**324**	356	**958**	1,166
Total transportation costs ($/boe)	**0.94**	0.76	**0.90**	0.85

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, 2020, transportation expenses were $0.94 per boe and were higher in comparison to $0.76 per boe for the quarter ended September 30, 2019. For the nine months ended September 30, 2020, transportation expenses were $0.90 per boe and were higher in comparison to $0.85 per boe for the nine months ended September 30, 2019.

Operating Income and Netback

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Revenue[1]	**10,846**	17,395	**29,105**	56,600
Royalties	**(790)**	(1,658)	**(2,227)**	(4,759)
Operating expenses	**(4,966)**	(6,295)	**(15,421)**	(19,133)
Transportation expenses	**(324)**	(356)	**(958)**	(1,166)
Operating income [2]	**4,766**	9,086	**10,499**	31,542
Sales volume (Mboe)	**344.3**	467.4	**1,066.6**	1,365.0
Per boe				
Revenue[1]	**31.50**	37.22	**27.29**	41.47
Royalties	**(2.29)**	(3.55)	**(2.09)**	(3.49)
Operating expenses	**(14.42)**	(13.47)	**(14.46)**	(14.02)
Transportation expenses	**(0.94)**	(0.76)	**(0.90)**	(0.85)
Operating netback per boe [2]	**13.85**	19.44	**9.84**	23.11
Operating income profit margin [2]	**44%**	52%	**36%**	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 in the third quarter and first nine months of 2020 decreased substantially compared to the same periods in 2019 reflecting the significant decreases to realized prices over these periods.

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	
	2020	2019	**2020**	2019
Gross G&A expenditures	**1,125**	1,966	**3,806**	6,242
Capitalized and recoveries	**(180)**	(407)	**(692)**	(1,305)
General and administrative expenses	**945**	1,559	**3,114**	4,937
G&A expenses ($/boe)	**2.74**	3.34	**2.92**	3.62
% Capitalized and recoveries	**16%**	21%	**18%**	21%

For the quarter ended September 30, 2020, G&A expenses were $0.9 million ($2.74 per boe) compared to $1.6 million ($3.34 per boe) for the same period in 2019. For the nine months ended September 30, 2020, G&A expenses were $3.1 million ($2.92 per boe) compared to $4.9 million ($3.62 per boe) for the same period in 2019. These decreases on a total and per boe basis were due to the cost cutting measures taken by the Company as a result of the COVID-19 pandemic, specifically a 20% salary rollback to field and office salaries, in addition to $0.5 million received from the Canada Emergency Wage Subsidy.

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 (loss) and comprehensive (loss).

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Share-based compensation	**176**	309	**567**	769
Capitalized portion	**(42)**	(71)	**(131)**	(171)
Share-based compensation expense	**134**	238	**436**	598

During the nine months ended September 30, 2020, 148,500 options were granted and 78,000 options were forfeited. At September 30, 2020, 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	
	2020	2019	**2020**	2019
Depletion and depreciation ($'000s)	**4,666**	7,606	**16,076**	21,977
Depletion and depreciation ($/boe)	**13.55**	16.27	**15.07**	16.10

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 $4.7 million ($13.55 per boe) for the quarter ended September 30, 2020 compared to $7.6 million ($16.27 per boe) for the same period in 2019. Depletion and depreciation was $16.1 million ($15.07 per boe) for the nine months ended September 30, 2020 compared to $22.0 million ($16.10 per boe) for the same period in 2019. These decreases on a total basis are due to the reduced production in the three and nine months ended September 30, 2020 compared to the same periods in 2019. The decrease on a per boe basis for the three months ended September 30, 2020 compared to the same period in 2019 is due to the impairment of Property, plant and equipment recognized in the first quarter of 2020 which resulted in lower net book values subject to depletion with a smaller reduction to proven plus probable reserves.

Impairment loss

At September 30, 2020 there were no indicators of impairment or impairment reversal.

Indicators of impairment relating to Property, plant and equipment were considered to exist as at March 31, 2020 as the Company's net assets were greater than its market capitalization and due to significant decreases in estimated future commodity prices. Impairment tests were performed for each the Company's CGUs which resulted in an impairment loss of $65.7 million being recorded in the Company's statement of profit (loss) and comprehensive income (loss) relating to the Company's Pigeon Lake ($19.0 million), Pembina ($25.7 million), Rocky ($18.9 million) and Huxley ($2.1 million) CGUs. The Company used the income approach technique to measure fair value of the CGUs whereby the net present value of the after tax future cash flows were calculated using a discount rate of 13% for Huxley and 12% for all other CGUs. The future cash flows were based on level 3 fair value hierarchy inputs: the Company's reserves prepared by its independent reserves evaluator, 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, 2019 have been updated by internal qualified reserve engineers to March 31, 2020.

At September 30, 2020 there were no indicators of impairment relating to the Company's Exploration and evaluation assets. An impairment test relating to the Company's Exploration and evaluation assets was performed as at March 31, 2020, with no impairment being recorded.

Finance expenses

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Interest expense (Credit Facility and other)	**1,050**	637	**2,148**	1,920
Interest expense (Lease liabilities)	**12**	4	**38**	13
Accretion on decommissioning obligations	**318**	278	**936**	902
Finance expense	**1,380**	919	**3,122**	2,835

Finance expenses were $1.4 million for the third quarter of 2020, compared to $0.9 million in the third quarter of 2019. Finance expenses were $3.1 million for the first nine months of 2020, compared to $2.8 million in the first nine months of 2019. Finance expenses increased for the three and nine months ended September 30, 2020 compared to the same periods in 2019 due to the higher bank debt outstanding during 2020 and increases to interest rates under the Company's Senior Credit Facilities.

Income taxes

The Company has not recognized a deferred tax asset at September 30, 2020. The Company recognized deferred tax expense of $nil and $30.3 million during the three and nine months ended September 30, 2020 respectively.

The deferred tax asset is supported by the expected future utilization of tax attributes based upon future cashflows derived from the Company's updated forecasts and independent year end reserve report using the total proven cashflows and expenditures and factoring in expected corporate general and administrative and interest expenses. As a result of the decrease in these future cashflows, the deferred tax asset was reduced by $48.4 million as at September 30, 2020 (September 30, 2019: $nil) with a corresponding charge to deferred income tax expense.

During the quarter ended June 30, 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12% to 8% over four years.. 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 recognized a reduction to its deferred tax asset and a deferred income tax expense of $1.6 million during the nine months ended September 30, 2020 (September 30, 2019: $8.5 million) due to the decrease in value of future deductibility of tax losses generated during the nine months ended September 30, 2020.

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at September 30, 2020.

Non-capital loss carryforward balances	$	109,203
Share issue costs		952
Canadian Exploration Expenses (CEE)		64,773
Canadian Development Expenses (CDE)		63,170
Canadian Oil and Gas Property Expenses (COGPE)		114,301
Undepreciated Capital Cost (UCC)		47,980
Total	$	400,379

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. Adjusted funds flow is calculated by the Company as funds flow adjusting for decommissioning 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	
	2020	2019	**2020**	2019
Funds flow	**1,768**	6,397	**3,607**	23,391
Decommissioning expenditures	**240**	489	**539**	1,303
Adjusted funds flow(1)	**2,008**	6,886	**4,146**	24,694

(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 months ended September 30, 2020, was $1.8 million compared to $6.4 million for the same period in 2019. Adjusted funds flow for the three months ended September 30, 2020 was $2.0 million compared to $6.9 million for the same period in 2019. Funds flow for the nine months ended September 30, 2020, was $3.6 million compared to $23.4 million for the same period in 2019. Adjusted funds flow for the nine months ended September 30, 2020 was $4.1 million compared to $24.7 million for the same period in 2019. These changes are reflective of the changes to benchmark prices realized during the respective periods and the impacts of the temporary production curtailment implemented in response to the COVID-19 pandemic.

CAPITAL EXPENDITURES

Capital expenditures for the three and nine months ended September 30, 2020 were $0.4 million and $12.2 million, respectively. The breakdown of capital expenditures is shown below:

The breakdown of expenditures is shown below:

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Land and lease	**9**	16	**46**	69
Drilling & completions	**190**	6,792	**9,609**	21,066
Facilities and equipping costs	**54**	935	**2,300**	5,226
Total exploration and development capital	**253**	7,743	**11,955**	26,361
Office and Capitalized G&A	**129**	339	**547**	1,172
Total	**382**	8,082	**12,502**	27,533
Net Property Acquisitions/(Dispositions)(2)	**(5)**	-	**(265)**	78
Total capital expenditures	**377**	8,082	**12,237**	27,611

(2) 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 capital program for the nine months ended September 30, 2020 consisted of $12.5 million of development capital. The Company drilled one (1.0 net) extended reach horizontal ("ERH") well in Willesden Green and three (3.0 net) one-mile horizontal wells in Pembina during the first quarter of 2020, amounting to an equivalent of 4.5 gross horizontal miles (4.5 net horizontal miles). The Company also completed a water disposal facility in Pembina that will payout in less than one year and have long-term operating cost savings.

As a result of the significant drop and volatility in world crude oil prices as a result of the COVID-19 outbreak and the corresponding OPEC+ oil price war, InPlay suspended its 2020 capital program after the capital program for the first quarter of 2020 was completed. On November 2, 2020, the Company announced that it was commencing a three well capital program in the Willesden Green area in the fourth quarter of 2020.

Drilling statistics are shown below:

	Three months ended September 30				Nine months ended September 30			
	2020		2019		**2020**		2019	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**-**	**-**	6.0	3.5	**4.0**	**4.0**	13.0	8.2
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**-**	**-**	6.0	3.5	**4.0**	**4.0**	13.0	8.2
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 12, 2020, there were 68,256,616 common shares outstanding and 5,312,800 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, 2020 and September 30, 2019.

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.

On July 14, 2020, the Company entered into an Amended and Restated Credit Agreement ("ARCA") with its syndicate of lenders. The Company's amended credit facilities (the "Senior Credit Facilities") total $65 million and consist of a $22.5 million revolving line of credit, a $10 million operating line of credit (together, the "Revolving Facilities") and a $32.5 million term loan (the "Term Loan"). The Term Loan has a maturity date of May 31, 2021. The Revolving Facilities have a maturity date of May 31, 2021, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable at May 31, 2021. The Senior Credit Facilities are secured by a floating charge debenture and a general security agreement on the assets of the Company. At September 30, 2020 the Company had drawn $61.1 million on the Senior Credit Facilities. There are standard reporting covenants under the Senior Credit Facilities, however there are no financial covenants. The Company was in compliance with these standard reporting covenants as at September 30, 2020.

Under the ARCA, advances can be drawn as prime rate loans and bear interest at the bank's prime lending rate plus interest rates between 2.00% and 5.50% for the Revolving Facilities and between 5.00% and 8.50% for the Term Loan. Advances may also be drawn as banker's acceptances, Libor loans, and letters of credit, subject to Canadian interest benchmark rates plus margins ranging from 3.00% to 6.50% for the revolving line of credit and 6.00% to 9.50% for the Term Loan. Standby fees are charged on the undrawn portion of the Senior Credit

Facilities at rates ranging from 0.750% to 1.625%. These interest rates, fees and margins vary based on adjusted debt to earnings metrics determined at each quarter end for the preceding 12 months.

The available lending limit of the Revolving Facilities is scheduled for semi-annual review on or before November 30, 2020 and annual renewal on May 31, 2021, and is based on the Lenders' interpretation of the Company's reserves and future commodity prices. In conjunction with the finalization of the BDC Term Facility (as defined below), InPlay's current syndicate of lenders have agreed that there will be no change in the borrowing base under the Company's Senior Credit Facilities, which total $65 million, at the next semi-annual borrowing base review scheduled for November 30, 2020. There can be no assurance that the amount or terms of the Senior Credit Facilities will not be adjusted at the next annual review. In the event that the lenders reduce the Revolving Facilities' 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.

On October 30, 2020 the Company entered into a term loan with the Business Development Bank of Canada ("BDC") under their Business Credit Availability Program ("BCAP") which provides the Company access to a non-revolving $25 million, second lien, four year term loan facility (the "BDC Term Facility"), of which the full $25 million has been drawn as of November 2, 2020. The BDC Term Facility has a maturity date of October 30, 2024 and is secured by a floating charge debenture and a general security agreement on the assets of the Company. There are standard reporting covenants under the BDC Term Facility and certain operational covenants, however there are no financial covenants.

Under the BDC Term Facility, draws incur an interest rate equal to the greater of the interest rate charged on the Company's operating line of credit or 5% for the first year and increasing by 1% at each anniversary date of the facility. Standby fees are charged on the undrawn portion of the BDC Term Facility at a rate of 0.50%. Annual renewal fees are charged on the full BDC Term Facility amount at a rate of 1.25% at inception, 1% on the first anniversary date, 1.25% on the second anniversary date and 1.5% on the third anniversary date.

In addition to the amount drawn on the Senior Credit Facilities at September 30, 2020 the Company had a working capital deficit of $3.1 million.

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, 2020, these obligations include:

- **Loan agreements** – On July 14, 2020, the Company's Senior Credit Facilities were amended to include a $32.5 million Term Loan with a maturity date of May 31, 2021 and a $32.5 million revolving line of credit that, if not extended, any outstanding balances would become repayable on May 31, 2021. The Company has also entered into a term loan with the BDC for a non-revolving $25 million, second lien, four year term loan facility (the "BDC Term Facility"). The BDC Term Facility has a maturity date of 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, 2020 were not recognized as a liability at September 30, 2020.

As at September 30, 2020 the Company had the following minimum contractual obligations:

Contractual obligations (in thousands of dollars)	Payments due by year 2020	2021	2022	2023	2024	Thereafter
Accounts payable	12,352	-	-	-	-	-
Bank debt - principal[1]	-	61,117	-	-	-	-
Bank debt - interest[2]	1,021	1,704	-	-	-	-
Non-cancellable office leases	94	377	31	-	-	-
Other leases	76	131	50	17	8	-
Firm service[3]	71	264	193	173	130	84
Total	13,614	63,593	274	190	138	84

(1) Assumes the Senior Credit Facilities are not renewed on May 31, 2021, whereby outstanding balances become due on May 31, 2021.

(2) Assumes interest is incurred on bank debt outstanding at September 30, 2020 at the Company's effective interest rate during the current quarter and the principal balance of the Senior Credit Facilities 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 and nine months ended September 30, 2020. 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 audited annual financial statements for the years ended December 31, 2019 and December 31, 2018.

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.

Deferred tax assets are recognized only if it is probable that future taxable amounts will be available to utilize those temporary differences and losses. As at December 31, 2019, the deferred tax asset utilization was supported primarily by future cashflows derived from the Company's independent year end reserve report using the total proven and probable cashflows. Given the current market conditions as a result of the COVID-19 outbreak, management has estimated that the total proven reserves of the Company more accurately support the future utilization of the deferred tax asset as at March 31, 2020. This change in estimate has resulted in the recognition of additional deferred income tax expense of $2.7 million in the statement of (loss) and comprehensive (loss) for the three and nine months ended September 30, 2020 with a corresponding reduction to deferred tax asset.

CHANGES IN ACCOUNTING POLICIES

There were no new or amended accounting standards or interpretations adopted in the nine months ended September 30, 2020, except as noted below.

Government Grants

Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to them and the grants will be received. If a grant is received before it is certain whether compliance with all conditions will be achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the conditions of a grant relate to income or expense, it is recognized in the statements of (loss) and comprehensive (loss) in the period in which the expenditures are incurred or income is earned. When the conditions of a grant relate to an underlying asset, it is recognized as a reduction to the carrying amount of the related asset and amortized into income on a systematic basis over the expected useful life of the underlying asset through Depletion and depreciation.

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, 2020 and ended on September 30, 2020 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 certain Canadian securities regulatory authorities on SEDAR at www.sedar.com.

Through the first few months of 2020, oil prices deteriorated due to softening global demand caused by the COVID-19 impact. This situation was exacerbated in early March with no agreement to cut oil supply from OPEC+ and an announcement from Saudi Arabia that they intend to relax all quotas effective immediately. With the spread of COVID-19 and additional oil supply expected to come on-stream over the near term, oil prices and global equity markets have deteriorated significantly and are expected to remain under pressure. The extreme supply / demand imbalance is anticipated to cause a reduction in industry spending in 2020.

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.

Upon the occurrence of a natural disaster, or upon an incident of war, riot or civil unrest, the impacted country, province, or region may not efficiently and quickly recover from such event, which could have a materially adverse effect on the Company, its customers, and/or either of their businesses or operations. Terrorist attacks, public health crises including epidemics, pandemics or outbreaks of new infectious disease or viruses (including, most recently, COVID-19, civil unrest and related events can result in volatility and disruption to local and global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company, its customers, and/or either of their businesses or operations.

OUTLOOK

Securing the BDC Term Facility, closing the strategic Cardium asset acquisition and implementing our fourth quarter 2020 capital program places the Company in a strong position and provides the Company with the liquidity required to return to pre-COVID levels of production, reserve values and revenues in a reasonable time frame alongside expected increasing commodity pricing. The Company will now be able to continue with its strategy of generating organic growth and free cash flow through our top-tier drilling inventory and pacesetting drilling results or potentially taking advantage of the current economic environment through strategic A&D activity. These actions complemented by our solid low decline asset base will support continued growth in production and free cash flow as commodity prices recover.

The fourth quarter of 2020 includes a planned development capital program that begins with the drilling of three 100% working interest ERH Cardium wells in Willesden Green and construction of the associated required infrastructure. The Company expected drilling to start by the end of October but the local County has implemented road bans that have delayed the start by approximately another two weeks. With the latest delay we now believe that it will be difficult to see production from these wells in 2020 but still anticipate annual average 2020 production close to 4,000 boe/d (approximately 68% oil & liquids). InPlay anticipates that its current base production along with the addition of production from the upcoming three wells will bring production back to 2019 pre-COVID levels of approximately 5,000 boe/d in the first quarter of 2021.

The Company has started planning its capital program for 2021 which will be determined through the balance of the current year and released in early 2021. The size of InPlay's 2021 capital program remains subject to expected crude oil demand recovery and resulting commodity pricing improvements. When drilling begins in 2021 current expectations are that it will start on our most recently acquired Pembina asset.

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 2020**	Q2 2020	Q1 2020	Q4 2019
Oil and natural gas sales	**10,846**	5,167	13,092	18,425
Oil and natural gas sales, net of royalties	**10,056**	4,639	12,183	17,357
(Loss)	**(2,717)**	(6,188)	(100,497)	(18,892)
(Loss) per share, basic and diluted	**(0.04)**	(0.09)	(1.47)	(0.28)
Exploration and development capital expenditures	**382**	488	11,632	4,574
Property acquisitions/(dispositions)	**(5)**	(260)	-	14
Funds flow	**1,768**	(1,395)	3,235	7,592
Adjusted funds flow(1)	**2,008**	(1,279)	3,418	7,846
Adjusted funds flow per share, basic and diluted(1)	**0.03**	(0.02)	0.05	0.11
Adjusted funds flow per boe(1)	**5.83**	(4.46)	7.85	17.06
Net debt	**64,246**	65,487	63,713	55,170

	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

(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.

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) during 2018. 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 consisted of $32.1 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 year ended December 31, 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.

A writedown of the deferred income tax asset of $18.4 million was recognized during the quarter ended December 31, 2019 as a result of a decrease in the future cash flows supporting the future utilization of this asset, with a corresponding charge to deferred income tax expense.

InPlay's capital program for the nine months ended September 30, 2020 consisted of $12.5 million of development capital focused in the Willesden Green and Pembina Cardium areas. The Company drilled one (1.0 net) extended reach horizontal ("ERH") wells and three (3.0 net) one-mile horizontal wells all during the first quarter of 2020, amounting to an equivalent of 4.5 gross horizontal miles (4.5 net horizontal miles). One (1.0 net) ERH well was drilled in Willesden Green and three (3.0 net) horizontal wells were drilled in Pembina. The Company also completed a water disposal facility in Pembina that will payout in less than one year and have long-term operating cost savings.

An impairment of $65.7 million was recognized in the quarter ended March 31, 2020 due to decreases in the recoverable amount of the Company's CGUs. A writedown of the deferred income tax asset of $46.4 million was also recognized during the quarter as a result of a decrease in the future cash flows supporting the future utilization of this asset, with a corresponding charge to deferred income tax expense.

As a result of the significant drop and volatility in world crude oil prices as a result of the COVID-19 outbreak and the corresponding OPEC+ oil price war, InPlay suspended its 2020 capital program after the capital program for the first quarter of 2020 was completed. On November 2, 2020, the Company announced that it was commencing a three well capital program in the Willesden Green area in the fourth quarter of 2020.

SELECTED ANNUAL INFORMATION

Years ended December 31

(in thousands, except per share amounts)		2019	2018	2017
Total oil and natural gas sales[(1)]	$	**75,025**	76,419	62,239
Oil and natural gas sales, net of royalties[(1)]		**69,198**	68,410	55,972
(Loss)		**(26,842)**	(8,598)	(7,701)
(Loss) per share, basic and diluted		**(0.39)**	(0.13)	(0.12)
Total assets		**298,006**	314,021	323,793
Total bank loans		**55,635**	45,400	44,888
Total net debt		**55,170**	53,670	51,266

(1) The oil and natural gas sales exclude realized and unrealized gains (losses) on risk management derivative contracts: 2019 excludes $0.02 million realized gain and ($0.1) million unrealized loss; 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.

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 "free cash 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 and a reconciliation to the nearest GAAP 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:

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Adjusted funds flow ($000s)	**2,008**	6,886	**4,146**	24,694
Weighted avg. number of common shares (basic and diluted ('000s))	**68,257**	68,257	**68,257**	68,257
Adjusted funds flow per share, basic and diluted	**0.03**	0.10	**0.06**	0.36

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:

	Three Months Ended September 30		Nine Months Ended September 30	
	2020	2019	**2020**	2019
Adjusted funds flow ($000s)	**2,008**	6,886	**4,146**	24,694
Sales volume (Mboe)	**344.3**	467.4	**1,066.6**	1,365.0
Adjusted funds flow per boe	**5.83**	14.73	**3.89**	18.09

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 and a reconciliation to the nearest GAAP 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.

Free Cash Flow

Management considers free cash flow an important measure to identify the Company's ability to improve the financial condition of the Company through debt repayment, which has become more important recently with the introduction of second lien lenders. Free cash flow is calculated by the Company as funds flow adjusting for decommissioning expenditures, less capital expenditures and is a measure of the cashflow remaining after capital expenditures that can be used for additional capital activity, repay debt or decommissioning expenditures.

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:

- the estimated time to payout of wells;
- production estimates including timing of production and the impact thereof;
- expectations regarding the business environment, industry conditions and future commodity prices, including the belief that commodity pricing will start gaining momentum in 2021 and beyond due to declining worldwide production;
- that the BDC Term Facility, closing the strategic Cardium asset acquisition and implementing our fourth quarter 2020 capital program places the Company in a strong position and provides the Company with the liquidity required to return to pre-COVID levels of production, reserve values and revenues;
- the belief that current base production along with the addition of production from the upcoming three wells will bring production back to 2019 pre-COVID levels of approximately 5,000 boe/d in the first quarter of 2021;
- expectations regarding InPlay's 2020 capital program, future operating costs and cash flows;
- 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;
- future costs, expenses and royalty rates;
- the volume and product mix of InPlay's oil and gas production;
- 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; 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, potential shut-ins of production, 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; the impact of COVID-19; 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).

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