Management's Discussion and Analysis

For the three and nine months ended September 30, 2021

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2021 AND SEPTEMBER 30, 2020

The following management's discussion and analysis ("**MD&A**") is dated November 9, 2021 and should be read in conjunction with the condensed, unaudited financial statements of InPlay Oil Corp. ("**InPlay**" or the "**Company**") for the three and nine months ended September 30, 2021 and September 30, 2020 and the audited annual financial statements for the years ended December 31, 2020 and December 31, 2019. 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 Ratios", 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.

DESCRIPTION OF BUSINESS

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.

REVIEW OF FINANCIAL RESULTS

Production

Average production volumes for the three and nine months ended September 30, 2021 and September 30, 2020 were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Crude oil (bbls/d)	**3,154**	1,973	**2,922**	1,976
NGLs (boe/d)	**663**	598	**731**	655
Natural gas (Mcf/d)	**13,166**	7,029	**10,831**	7,572
Total (boe/d)(1)(2)(3)	**6,011**	3,742	**5,458**	3,893
Crude oil and NGLs (%)	**64%**	69%	**67%**	68%

(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.

(2) References to crude oil, NGLs or natural gas production in this MD&A refer to the light and medium crude oil, natural gas liquids and conventional natural gas product types, respectively, as defined in National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("Nl 51-101").

(3) See "Production Breakdown by Product Type" at the end of this MD&A.

Production for the three and nine months ended September 30, 2021 was 61% and 40% higher respectively compared to the three and nine months ended September 30, 2020, primarily as a result of the added volumes from the drilling program during the fourth quarter of 2020 and first nine months of 2021 and reflective of the temporary production curtailments implemented by the Company in the second quarter of 2020 due to the COVID-19 pandemic. The reduced light oil and liquids weighting to 64% in the quarter is mainly due to less

NGLs extracted as a result of a temporary change in the extraction process at a deep cut plant and a fire at another plant utilized by InPlay.

InPlay's capital program for the first nine months of 2021 consisted of $27.4 million of development capital. In the first quarter of 2021, the Company drilled three (3.0 net wells) extended reach horizontal ("ERH") wells in Pembina and completed one (0.2 net) non-operated Nisku ERH well. The Company drilled three (3.0 net wells) ERH wells in Pembina in the second quarter of 2021 with one of these wells rig released in early July. All three of these wells were brought on production at the end of July. In the third quarter of 2021, the Company completed the drilling operations of two (2.0 net) ERH wells in Pembina, with these wells being completed and are currently being brought on production. The Company also participated in the drilling of one (0.2 net) non-operated Nisku ERH well and one (0.2 net) non-operated Willesden Green ERH well during the third quarter of 2021. This activity amounted to an equivalent of 17.5 gross horizontal miles (13.0 net horizontal miles). This capital spending also included the construction of a multi-well battery in Pembina which is anticipated to accommodate all of our future development of the area over the next three years.

Crude oil and natural gas sales

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Crude oil	**23,875**	8,423	**59,341**	22,220
NGLs	**2,745**	921	**6,878**	2,458
Natural gas	**4,711**	1,502	**10,380**	4,427
Total crude oil and natural gas sales	**31,331**	10,846	**76,599**	29,105

Prices

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Crude oil ($/bbl)	**82.29**	46.41	**74.39**	41.04
NGLs ($/boe)	**45.01**	16.73	**34.47**	13.70
Natural gas ($/Mcf)	**3.89**	2.32	**3.51**	2.13
Total ($/boe)	**56.66**	31.50	**51.41**	27.29
WTI ($USD/bbl)	**70.56**	40.93	**64.82**	38.32
AECO ($/GJ)	**3.41**	2.12	**3.11**	1.98

West Texas Intermediate ("WTI") prices improved in the three and nine months ended September 30, 2021 compared to average prices during the three and nine months ended September 30, 2020 which were impacted by the COVID-19 pandemic. In the third quarter of 2021, WTI oil prices increased 72% averaging $70.56 US per bbl compared to $40.93 US per bbl in the third quarter of 2020. In the nine months ended September 30, 2021, WTI oil prices increased 69% averaging $64.82 US per bbl compared to $38.32 US per bbl in nine months ending September 30, 2020.

Differentials between WTI oil prices and prices received in Alberta strengthened in the three and nine months ended September 30, 2021 and compared to the same periods in 2020. These differentials can be 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 $4.08 US per barrel discount for the third quarter of 2021 compared to $3.51 US per barrel discount for the third quarter of 2020.

Monthly index differentials averaged $4.14 US per barrel discount for the nine months ended September 30, 2021 compared to $5.74 US per barrel discount for the same period in 2020.

Realized oil prices are adjusted for the Canada/US exchange rate which increased averaging 0.79 for the third quarter of 2021 compared to 0.75 during the third quarter of 2020. The Canada/US exchange rate also increased over the first nine months of 2021 to 0.80 compared to 0.74 over the first nine months of 2020.

Due to the items noted above, realized oil prices for the three and nine months ended September 30, 2021 increased compared to the three and nine months ended September 30, 2020. The Company's average net realized price for crude oil was $82.29 per bbl for the third quarter of 2021, 77% higher than the third quarter 2020 realized price of $46.41 per bbl. The Company's average net realized price for crude oil was $74.39 per bbl for nine months ended September 30, 2021, 81% higher than the realized price of $41.04 per bbl for the same period during 2020.

In the third quarter of 2021, natural gas AECO daily index prices increased 61% averaging $3.41 per GJ compared to $2.12 per GJ in the third quarter of 2020. In the first nine months of 2021, natural gas AECO daily index prices increased 57% averaging $3.11 per GJ compared to $1.98 per GJ in the first nine months of 2020.

The Company's average realized natural gas sales price was $3.89 per Mcf for the third quarter of 2021, 68% higher than the third quarter of 2020 realized price of $2.32 per Mcf on improved natural gas markets. The Company's average realized natural gas sales price was $3.51 per Mcf for the nine months ended September 30, 2021, 65% higher than the realized price of $2.13 per Mcf for the nine months ended September 30, 2020, also on improved natural gas markets.

Realized NGL pricing improved for the three months ended September 30, 2021 compared to the same period in 2020. The Company's average realized NGL price was $45.01 per boe for the third quarter of 2021, 169% higher than the third quarter of 2020 realized price of $16.73 per boe as a result of improved ethane, propane and butane markets and higher condensate and pentane prices which track WTI pricing. The Company's average realized NGL sales price was $34.47 per boe for the first nine months of 2021, 152% higher than the realized price of $13.70 per boe for the same period in 2020 as a result of improved ethane, propane and butane markets.

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	
	2021	2020	**2021**	2020
Total royalties ($'000s)	**3,352**	790	**6,963**	2,227
Total royalties (% of sales)	**10.7%**	7.3%	**9.1%**	7.7%
Total royalties ($/boe)	**6.06**	2.29	**4.67**	2.09

Royalties as a percentage of revenue and on a per boe basis increased during the three and nine months ended September 30, 2021 compared to the same periods in 2020 due to the sliding scale nature of some oil royalties which increases the percentage during periods of high commodity prices.

Derivative contracts

The Company's production is usually sold using near-term contracts with complementary spot sales as needed, 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, 2021 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
Canadian dollar	250	65.00/bbl	February 1, 2021 – December 31, 2021

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

Currency denomination	Volume (bbl/day)	Bought put price	Sold call price	Term
US dollar	250	52.00/bbl	69.00/bbl	July 1, 2021 – Dec. 31, 2021

(1) Costless collar indicates InPlay concurrently bought put and sold 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: three-way collar[2] (crude oil pricing WTI):

Currency denomination	Volume (bbl/day)	Sold put price	Bought put price	Sold call price	Term
US dollar	250	45.00/bbl	49.50/bbl	61.00/bbl	April 1, 2021 – Dec. 31, 2021
US dollar	750	45.33/bbl	50.67/bbl	63.00/bbl	July 1, 2021 – Dec. 31, 2021

(2) The WTI three-way collars are a combination high priced sold call, low priced sold put and a mid priced bought put. The high sold call price is the maximum price the Company will receive for the contract volumes. The mid bought put price is the minimum price InPlay will receive, unless the market price falls below the low sold put strike price, in which case InPlay receives market price less the difference between the mid bought put price minus the low sold put price.

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

Currency denomination	Volume (GJ/day)	Average swap price	Term
Canadian dollar	2,000	2.34/GJ	January 1, 2021 – December 31, 2021
Canadian dollar	2,750	2.54/GJ	April 1, 2021 – October 31, 2021

Type of contract: costless collar[3] (natural gas pricing AECO):

Currency denomination	Volume (GJ/day)	Bought put price	Sold call price	Term
Canadian dollar	2,000	2.70/GJ	3.36/GJ	Nov. 1, 2021 – March 31, 2022

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

At September 30, 2021 the Company had the following forward exchange rate contracts outstanding.

Type of contract: swap (USD/CAD):

Reference currency	USD Amount ($'000s)	Exchange Rate (USD/CAD)	Term
US dollar	$4,680	1.2682	July 1, 2021 – December 31, 2021
US dollar	$3,600	1.2785	April 1, 2021 – December 31, 2021

The statements of profit (loss) and comprehensive income (loss) for the three and nine months ended September 30, 2021 reflected the following (losses) related to derivative contracts that were outstanding during 2021 and the comparative periods for 2020.

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Realized (loss)	**(1,917)**	(751)	**(9,564)**	(1,053)
Unrealized gain (loss)	**981**	393	**(2,049)**	(92)
Total (loss) on derivative contracts	**(936)**	(358)	**(11,613)**	(1,145)

Operating expenses

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Total operating costs ($'000s)	**6,763**	4,966	**19,315**	15,421
Total operating costs ($/boe)	**12.23**	14.42	**12.96**	14.46

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, 2021, operating expenses per boe decreased to $12.23 per boe compared to $14.42 per boe for the same period in 2020. For the nine months ended September 30, 2021, operating expenses per boe decreased to $12.96 per boe compared to $14.46 per boe for the same period in 2020. Improvements in operating costs on a per boe basis reflect fixed operating costs being incurred over a larger production base.

Transportation expenses

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Total transportation costs ($'000s)	**708**	324	**1,674**	958
Total transportation costs ($/boe)	**1.28**	0.94	**1.12**	0.90

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, 2021, transportation expenses were $1.28 per boe and were higher in comparison to $0.94 per boe for the quarter ended September 30, 2020. For the nine months ended September 30, 2021, transportation expenses were $1.12 per boe and were higher in comparison to $0.90 per boe for the nine months ended September 30, 2020. Increases to oil production resulted in higher transportation rates on a per boe basis given the higher transportation costs incurred on spot sales associated with new production.

These higher transportation costs were offset by higher realized oil prices through spot sales at a premium to index prices.

Operating Income and Netback

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Revenue[1]	**31,331**	10,846	**76,599**	29,105
Royalties	**(3,352)**	(790)	**(6,963)**	(2,227)
Operating expenses	**(6,763)**	(4,966)	**(19,315)**	(15,421)
Transportation expenses	**(708)**	(324)	**(1,674)**	(958)
Operating income [2]	**20,508**	4,766	**48,647**	10,499
Sales volume (Mboe)	**553.0**	344.3	**1,490.0**	1,066.6
Per boe				
Revenue[1]	**56.66**	31.50	**51.41**	27.29
Royalties	**(6.06)**	(2.29)	**(4.67)**	(2.09)
Operating expenses	**(12.23)**	(14.42)	**(12.96)**	(14.46)
Transportation expenses	**(1.28)**	(0.94)	**(1.12)**	(0.90)
Operating netback per boe [2]	**37.09**	13.85	**32.66**	9.84
Operating income profit margin [2]	**65%**	44%	**64%**	36%

(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 and Ratios" at the end of this MD&A.

Operating income and operating netback per boe in the three and nine months ended September 30, 2021 increased dramatically compared to the three and nine months ended September 30, 2020 reflecting the higher production volumes and significant increases 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	
	2021	2020	**2021**	2020
Gross G&A expenditures	**1,854**	1,125	**5,206**	3,806
Capitalized and recoveries	**(289)**	(180)	**(973)**	(692)
General and administrative expenses	**1,565**	945	**4,233**	3,114
G&A expenses ($/boe)	**2.83**	2.74	**2.84**	2.92
% Capitalized and recoveries	**16%**	16%	**19%**	18%

For the quarter ended September 30, 2021, G&A expenses were $1.6 million ($2.83 per boe) compared to $0.9 million ($2.74 per boe) for the same period in 2020. For the nine months ended September 30, 2021, G&A expenses were $4.2 million ($2.84 per boe) compared to $3.1 million ($2.92 per boe) for the same period in 2020. G&A expenses on a per boe basis were relatively flat in the third quarter and first nine months of 2021 compared to the same periods in 2020. Total G&A expenses increased in the third quarter and first nine months of 2021 in comparison to the third quarter and first nine months of 2020, returning to normalized levels compared to the lower G&A expenses in the third quarter of 2020 realized from purposeful reductions made at the onset of the COVID-19 pandemic. The initiatives taken in 2020 to reduce certain aspects of compensation expense have now returned to normal levels and government wage subsidies received, which started in the second quarter of 2020, ended during the second quarter of 2021 for InPlay.

Share-based compensation expenses

The Company accounts for share-based compensation using the fair value method of accounting, and share-based compensation (net of amounts capitalized) is included in the determination of profit (loss) and comprehensive income (loss).

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Share-based compensation	**257**	176	**896**	567
Capitalized portion	**(23)**	(42)	**(89)**	(131)
Share-based compensation expense	**234**	134	**807**	436

During the nine months ended September 30, 2021, 1,042,900 options and 617,650 deferred share units ("DSUs") were granted, 37,000 options were exercised.

At September 30, 2021, the maximum number of stock options available for grant was 6,829,362 of which 6,206,450 have been granted and remain outstanding.

Depletion and depreciation

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Depletion and depreciation ($'000s)	**7,800**	4,666	**19,749**	16,076
Depletion and depreciation ($/boe)	**14.10**	13.55	**13.25**	15.07

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 profit (loss) and comprehensive income (loss) on a unit of production basis over proved plus probable reserves. The carrying costs of office and computer equipment are recognized as depreciation expense in the statements of profit (loss) and comprehensive income (loss) on a straight-line or declining-balance basis.

Depletion and depreciation was $7.8 million ($14.11 per boe) for the quarter ended September 30, 2021 compared to $4.7 million ($13.55 per boe) for the same period in 2020. Depletion and depreciation was $19.7 million ($13.25 per boe) for the nine months ended September 30, 2021 compared to $16.1 million ($15.07 per boe) for the same period in 2020. The increase on a total basis is due the higher productions volumes in the three and nine months ended September 30, 2021 compared to the same periods in 2020.

Impairment

At September 30, 2021 there were no indicators of impairment or impairment reversal relating to the Company's Property, plant and equipment assets.

At June 30, 2021 there were indicators of impairment reversal due to significant increases in estimated future commodity prices. Impairment reversal tests were performed for each the Company's CGUs which resulted in an impairment reversal of historical impairment charges of $58.3 million being recorded in the Company's statement of profit (loss) and comprehensive income (loss) relating to the Company's Pigeon Lake ($18.3 million), Pembina ($24.1 million), Rocky ($13.8 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, 2020 have been updated by internal qualified reserve engineers to June 30, 2021 for the purposes of this assessment.

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 for the purposes of this assessment.

At September 30, 2021 there were no indicators of impairment relating to the Company's Exploration and evaluation assets.

Exploration and evaluation expense

An amount of $5.5 million was recorded as Exploration and evaluation expense during the nine months ended September 30, 2021 relating to the expiry of undeveloped land leases during the period and anticipated near term undeveloped land lease expiries.

Finance expenses

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Interest expense (Credit Facility and other)	**1,304**	1,050	**4,378**	2,148
Interest expense (Lease liabilities)	**5**	12	**16**	38
Accretion on decommissioning obligations	**317**	318	**791**	936
Finance expense	**1,626**	1,380	**5,185**	3,122

Finance expenses were $1.6 million for the third quarter of 2021, compared to $1.4 million in the third quarter of 2020. Finance expenses were $5.2 million for the nine months ended September 30, 2021, compared to $3.1 million during the same period in 2020. These increases are due to higher outstanding debt levels in the three and nine months ended September 30, 2021 compared to the same periods in 2020 and the impact of higher interest rates incurred on the Senior Credit Facility interest rate grid caused by higher adjusted debt to earnings metrics for the preceding 12 months.

Income taxes

The Company has not recognized a deferred tax asset at September 30, 2021. The Company recognized deferred tax expense of $nil during the three and nine months ended September 30, 2021.

A 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 proved 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 increased by $13.8 million as at September 30, 2021 (September 30, 2020: $48.4 million) 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. During the quarter ended September 30, 2020, this tax rate decrease was accelerated to 8% effective July 1, 2020. 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 due to the decrease in value of future deductibility of tax losses generated during the period.

Subsequent to September 30, 2021, the Company received a letter from the CRA advising InPlay that they have accepted the Company's objection and the proposed reassessment has been dismissed relating to the matter described below.

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 TSX, was completed on November 7, 2016. The Arrangement constituted a reverse acquisition that involved 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. During the quarter ended June 30, 2019, the Company received a letter from the Canada Revenue Agency ("**CRA**") advising InPlay that it is proposing to reassess the Company's income tax filings relating to the November 7, 2016 Arrangement. The proposed reassessment seeks to disallow certain tax pools in the amount of $9.3 million. If these tax pools were to be disallowed there would be no impact on current tax payable but would result in a reduction of $9.3 million of losses which could have otherwise been carried forward into subsequent taxation years and a deferred income tax expense impact of $2.1 million.

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at September 30, 2021.

Non-capital loss carryforward balances	$	130,465
Share issue costs		374
Canadian Exploration Expenses (CEE)		64,773
Canadian Development Expenses (CDE)		63,889
Canadian Oil and Gas Property Expenses (COGPE)		104,380
Undepreciated Capital Cost (UCC)		44,486
Total	$	408,367

ADJUSTED FUNDS FLOW

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Funds flow	**15,186**	1,768	**29,466**	3,607
Decommissioning expenditures	**369**	240	**413**	539
Adjusted funds flow	**15,555**	2,008	**29,879**	4,146

Adjusted funds flow for the three months ended September 30, 2021 was $15.6 million compared to $2.0 million for the same period in 2020. Adjusted funds flow for the nine months ended September 30, 2021 was $29.9 million compared to $4.1 million for the same period in 2020. These significant increases are reflective of the higher sales volumes and increases in benchmark prices realized during the respective periods.

CAPITAL EXPENDITURES

Capital expenditures for the three and nine months ended September 30, 2021 were $10.5 million and $27.3 million, respectively. The breakdown of capital expenditures is shown below:

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Land and lease	**11**	9	**42**	46
Drilling & completions	**8,917**	190	**21,758**	9,609
Facilities and equipping costs	**1,270**	54	**4,685**	2,300
Total exploration and development capital	**10,198**	253	**26,485**	11,955
Office and Capitalized G&A	**259**	129	**925**	547
Total	**10,457**	382	**27,410**	12,502
Net Property (Dispositions)	**(2)**	(5)	**(83)**	(265)
Total capital expenditures	**10,455**	377	**27,327**	12,237

InPlay's capital program for the first nine months of 2021 consisted of $27.4 million of development capital. In the first quarter of 2021, the Company drilled three (3.0 net wells) extended reach horizontal ("ERH") wells in Pembina and completed one (0.2 net) non-operated Nisku ERH well. The Company drilled three (3.0 net wells) ERH wells in Pembina in the second quarter of 2021 with one of these wells rig released in early July. All three of these wells were brought on production at the end of July. In the third quarter of 2021, the Company completed the drilling operations of two (2.0 net) ERH wells in Pembina, with these wells being completed and are currently being brought on production. The Company also participated in the drilling of one (0.2 net) non-operated Nisku ERH well and one (0.2 net) non-operated Willesden Green ERH well during the third quarter of 2021. This activity amounted to an equivalent of 17.5 gross horizontal miles (13.0 net horizontal miles). This capital spending also included the construction of a multi-well battery in Pembina which is anticipated to accommodate all of our future development of the area over the next three years.

Drilling statistics are shown below:

	Three months ended September 30				Nine months ended September 30			
	2021		2020		**2021**		2020	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**5.0**	**3.4**	-	-	**10.0**	**8.4**	4.0	4.0
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**5.0**	**3.4**	-	-	**10.0**	**8.4**	4.0	4.0
Success rate	**100%**	**100%**	-	-	**100%**	**100%**	100%	100%

SUBSEQUENT EVENTS

Proposed Acquisition

On September 28, 2021, the Company entered into a definitive agreement (the "**Agreement**") to acquire Prairie Storm Resources Corp. ("**Prairie Storm**"), a light-oil Cardium focused producer with operations primarily in the Willesden Green area of central Alberta, pursuant to a plan of arrangement under the Business Corporations Act (Alberta) (the "**Arrangement**") . Pursuant to the Agreement, subsequent to satisfaction of the conditions thereto, InPlay will acquire all of the issued and outstanding common shares of Prairie Storm (the "**Prairie Storm Shares**") for consideration of: (a) the payment of an aggregate of approximately $39.9 million in cash; and (b) the issuance of an aggregate of approximately 8.3 million common shares of InPlay ("**InPlay Shares**"). The Arrangement is expected to close on or around November 30, 2021.

The Arrangement will be funded by a combination of a $11.5 million bought deal equity financing led by Eight Capital, as sole bookrunner, together with ATB Capital Markets as co-lead underwriters (the "**Financing**"), available borrowings under InPlay's Senior Credit Facility, as amended and described below, and the issuance to shareholders of Prairie Storm of approximately 8.3 million InPlay Shares.

Financing

On September 28, 2021, InPlay entered into an agreement with a syndicate of underwriters led by Eight Capital and ATB Capital Markets (the "**Underwriters**"), pursuant to which the Underwriters agreed to purchase for resale to the public, on a bought deal basis, 9.6 million subscription receipts ("**Subscription Receipts**") of InPlay at a price of $1.20 per Subscription Receipt for aggregate gross proceeds of approximately $11.5 million, inclusive of the full exercise of the Underwriters' over-allotment option. The Financing was closed on October 20, 2021. Each Subscription Receipt represents the right to receive, without payment of additional consideration or further action on the part of the holder, one (1) common share of InPlay upon completion of the Arrangement.

Senior Credit Facility Amendments

In connection with the Arrangement, on September 28, 2021 the Company entered into a commitment letter agreement with its current syndicate of Lenders pursuant to which the Lenders have agreed to increase the aggregate available borrowing capacity of InPlay's Senior Credit Facility from $65.0 million to $85.0 million, subject to and conditional upon the completion of the Arrangement and the Financing (the "**Senior Credit Facility Amendments**"). In addition to InPlay's current syndicated fully conforming, revolving Senior Credit Facility totaling $65 million, under the Senior Credit Facility Amendments, the Lenders have committed to provide InPlay with an additional $20 million syndicated term facility maturing November 30, 2022 (the "**Senior Term Facility**"). The Senior Term Facility will require mandatory repayments as follows: (i) $6 million by May 31, 2022; (ii) $7 million by August 31, 2022; and (iii) $7 million by November 30, 2022.

SHARE INFORMATION

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

As of November 9, 2021, there were 68,303,416 common shares outstanding and 6,188,300 stock options that, subject to vesting, are convertible into, or exercisable or exchangeable for, an equivalent number of common shares of the Company. In addition, there were 9,591,000 Subscription Receipts outstanding that are convertible into common shares on a one-for-one basis on completion of the Arrangement.

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, 2021 and September 30, 2020.

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 June 30, 2021, the Company renewed its credit facility with its syndicate of lenders (the "Senior Credit Facility") which totals $65 million and consists of a $55 million revolving line of credit and a $10 million operating line of credit. The Senior Credit Facility has a maturity date of May 30, 2022, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable at May 30, 2022. The Senior Credit Facility is secured by a floating charge debenture and a general security agreement on the assets of the Company. At September 30, 2021 the Company had drawn $40.1 million on the Senior Credit Facility. There are standard reporting covenants under the Senior Credit Facility, however there are no financial covenants. The Company was in compliance with these standard reporting covenants as at September 30, 2021.

Under the Senior Credit Facility, 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%. 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%. Standby fees are charged on the undrawn portion of the Senior Credit Facility 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 semi-annual renewal of the available lending limit of the Senior Credit Facility originally scheduled for November 30, 2021 will be performed in combination with the Senior Credit Facility Amendments described above, and is based on the Lenders' interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount or terms of the Senior Credit Facility will not be adjusted at the next semi-annual review. In the event that the lenders reduce the Senior Credit Facility's 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 provided the Company with 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 October 30, 2024 and is secured by a floating charge debenture and a general security agreement on the assets of the Company. At September 30, 2021 the Company had drawn the full $25.0 million on the BDC Term Facility and had accrued $1.2 million in interest that was added to the principal amount. 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.

The Company had letters of credit in the amount of $0.3 million outstanding at September 30, 2021 (December 31, 2020 - $0.3 million).

In addition to the amount drawn on the Senior Credit Facility and BDC Term Facility at September 30, 2021, the Company had a working capital deficit of $5.0 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, 2021, these obligations include:

- **Loan agreement** –The Company's Senior Credit Facility has a maturity date of May 30, 2022 and, if not extended, any outstanding balances would become repayable on May 30, 2022. The Company also has entered into a term loan with the BDC for a non-revolving $25 million, second lien, four year term facility (the "BDC Term Facility"). The BDC Term Facility has a maturity date of October 30, 2024. 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, 2021 were not recognized as a liability at September 30, 2021.

As at September 30, 2021 the Company had the following minimum contractual obligations:

Contractual obligations	Payments due by year					
(in thousands of dollars)	2021	2022	2023	2024	2025	Thereafter
Accounts payable	21,685	-	-	-	-	-
Bank debt - principal[(1)]	-	40,142	-	25,000	-	-
Bank debt - interest[(2)(3)]	989	2,830	1,883	3,031	-	-
Bank debt - fees[(4)]	250	313	375	-	-	-
Non-cancellable office leases	94	31	-	-	-	-
Other leases	26	49	17	8	-	-
Firm service	100	383	264	148	80	23
Total	23,144	43,748	2,539	28,187	80	23

(1) Assumes the Senior Credit Facility is not renewed on May 30, 2022, whereby outstanding balances become due on May 30, 2022 and the BDC Term Facility is payable on October 30, 2024.

(2) Assumes interest is incurred on bank debt outstanding on the Senior Credit Facility at September 30, 2021 at the Company's effective interest rate during the current quarter and the principal balance of the Senior Credit Facility is repaid on May 30, 2022.

(3) Assumes interest is incurred on the BDC Term Facility outstanding at September 30, 2021 at the interest rates prescribed in the term facility agreement, with interest in the first year added to the principal balance of the BDC Term Facility to be repaid on October 30, 2024.

(4) 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.

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, 2021. 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, 2020 and December 31, 2019.

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, 2021.

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, 2021 and ended on September 30, 2021 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

The emergence of COVID-19 has resulted in emergency actions by governments worldwide, and has impacted the Company's results, business, financial and operating conditions, and has negatively impacted the Canadian, U.S., and global economies; disrupted Canadian, U.S., and global supply chains; disrupted financial markets; contributed to a decrease in interest rates; resulted in ratings downgrades, credit deterioration and defaults in many industries; forced the closure of many businesses, led to loss of revenues, increased unemployment and bankruptcies; and necessitated the imposition of quarantines, physical distancing, business closures, travel restrictions, and sheltering-in-place requirements in Canada, the U.S., and other countries. If the pandemic is prolonged, including through subsequent waves, or if additional variants of COVID-19 continue to emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, the adverse impact on the economy could worsen. Moreover, it remains uncertain how the macroeconomic environment, and societal and business norms will be impacted following this COVID-19 pandemic. As a result, the Company's business, financial and operational conditions, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, and/or business plans may, in particular, and without limitation, may be adversely impacted as a result of the pandemic and/or decline in commodity prices. The full extent of the risks surrounding the severity and continuance of the COVID-19 pandemic is continually evolving and is not fully known at this time. Therefore, there is significant risk and uncertainty which may have a material and adverse effect on the Company's operations.

The extent to which the COVID-19 pandemic continues to impact the Company's financial results and condition or liquidity will depend on future developments in Canada, the U.S. and globally, including the widespread availability of efficient and accurate testing options, and effective treatment options or vaccines. Despite the approval of certain vaccines by the regulatory bodies in Canada and the U.S., the ongoing evolution of the efficiency of widespread distribution of an effective vaccine against COVID-19 and new variants thereof also continues to raise uncertainty.

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, the continuing impact of COVID-19 and travel bans 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.

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.

The COVID-19 pandemic has also created additional operational risks for the Company, including the need to provide enhanced safety measures for its employees and customers; comply with rapidly changing regulatory guidance; address the risk of, attempted fraudulent activity and cybersecurity threat behavior; and protect the integrity and functionality of the Company's systems, networks, and data as a larger number of employees work remotely. The Company is also exposed to human capital risks due to issues related to health and safety matters, and other environmental stressors as a result of measures implemented in response to the COVID-19 pandemic, as well as the potential for a significant proportion of the Company's employees, including key executives, to be unable to work effectively, because of illness, quarantines, sheltering-in-place arrangements, government actions or other restrictions in connection with the pandemic.

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

The Company's operational success in the Cardium and record results achieved during the quarter provide a solid foundation entering into the fourth quarter and looking forward to 2022. The increase in commodity prices and the pending addition of the Prairie Storm assets has the Company extremely well positioned financially and operationally going into 2022. Our updated pro-forma 2021 post-acquisition corporate guidance for 2021 and preliminary post-acquisition corporate outlook for 2022 remain unchanged. Please refer to our press release dated September 28, 2021 for further details.

We are very excited to begin integrating the Prairie Storm assets into our business and look forward to continuing to deliver the same operational excellence that we have previously delivered in our existing Cardium assets. The Company looks forward to executing on our strategy to generate measured production per share growth combined with strong free adjusted funds flow, debt reduction and maximizing returns to shareholders.

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 2021**	Q2 2021	Q1 2021	Q4 2020
Oil and natural gas sales	**31,331**	25,267	20,001	12,829
Oil and natural gas sales, net of royalties	**27,979**	22,901	18,756	12,132
Profit (loss)	**8,289**	59,127	(7,536)	(3,227)
Profit (loss) per share, basic	**0.12**	0.87	(0.11)	(0.05)
Profit (loss) per share, diluted	**0.12**	0.85	(0.11)	(0.05)
Exploration and development capital expenditures	**10,457**	4,744	12,209	10,633
Property acquisitions/(dispositions)	**(2)**	(101)	19	1,875
Adjusted funds flow	**15,555**	8,219	6,105	3,291
Adjusted funds flow per share, basic and diluted	**0.23**	0.12	0.09	0.05
Adjusted funds flow per boe	**28.13**	16.77	13.66	8.40
Net debt	**71,331**	76,113	79,780	73,681

	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	(0.04)	(0.09)	(1.47)	(0.28)
(Loss) per share, 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
Adjusted funds flow	2,008	(1,279)	3,418	7,846
Adjusted. funds flow per share, basic and diluted	0.03	(0.02)	0.05	0.11
Adjusted funds flow per boe	5.83	(4.46)	7.85	17.06
Net debt	64,246	65,487	63,713	55,170

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) 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 2020 capital program consisted of $23.1 million of development capital. The Company drilled four (4.0 net) ERH wells in Willesden Green, three (3.0 net) one-mile horizontal wells in Pembina and one (0.2 net) non-operated Nisku ERH well during the year ended December 31, 2020, amounting to an equivalent of 11 gross horizontal miles (9.4 net horizontal miles). The three (3.0 net) ERH wells in Willesden Green drilled in the fourth quarter were placed on production in the last week of December 2020. The one (0.2 net) ERH well in Pembina drilled in the fourth quarter was completed in January 2021 and placed on production in February. The Company also completed a water disposal facility in Pembina that is expected to payout in less than one year and generate 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. The Company resumed its capital program in the fourth quarter of 2020.

An impairment reversal of $58.3 million was recognized in the quarter ended June 30, 2021 due to increases in estimated future commodity prices and the recoverable amount of the Company's CGUs.

InPlay's capital program for the first nine months of 2021 consisted of $27.4 million of development capital. In the first quarter of 2021, the Company drilled three (3.0 net wells) extended reach horizontal ("ERH") wells in Pembina and completed one (0.2 net) non-operated Nisku ERH well. The Company drilled three (3.0 net wells) ERH wells in Pembina in the second quarter of 2021 with one of these wells rig released in early July. All three of these wells were brought on production at the end of July. In the third quarter of 2021, the Company completed the drilling operations of two (2.0 net) ERH wells in Pembina, with these wells being completed and are currently being brought on production. The Company also participated in the drilling of one (0.2 net) non-operated Nisku ERH well and one (0.2 net) non-operated Willesden Green ERH well during the third quarter of 2021. This activity amounted to an equivalent of 17.5 gross horizontal miles (13.0 net horizontal miles). This capital spending also included the construction of a multi-well battery in Pembina which is anticipated to accommodate all of our future development of the area over the next three years.

SELECTED ANNUAL INFORMATION

Years ended December 31

(in thousands, except per share amounts)		**2020**	2019	2018
Total oil and natural gas sales[(1)]	$	**41,934**	75,025	76,419
Oil and natural gas sales, net of royalties[(1)]		**39,010**	69,198	68,410
(Loss)		**(112,629)**	(26,842)	(8,598)
(Loss) per share, basic and diluted		**(1.65)**	(0.39)	(0.13)
Total assets		**211,035**	298,006	314,021
Total bank loans		**63,832**	55,635	45,400
Total net debt		**73,681**	55,170	53,670

(1) The oil and natural gas sales exclude realized and unrealized gains (losses) on risk management derivative contracts: 2020 excludes ($1.2 million) realized loss and ($1.3) million unrealized loss; 2019 excludes $0.02 million realized gain and ($0.1) million unrealized loss; and 2018 excludes ($4.1) million realized loss and $1.7 million unrealized gain.

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 AND RATIOS

Included in this document are references to the terms "operating income", "operating netback per boe", "operating income profit margin", "free adjusted funds flow" and "Net Debt to Quarterly Annualized EBITDA". 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 "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.

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 Adjusted Funds Flow

Management considers free adjusted funds flow an important measure to identify the Company's ability to improve its financial condition through debt repayment, which has become more important recently with the introduction of second lien lenders. Free 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 free adjusted funds flow may not be comparable to that reported by other companies. Free adjusted funds flow is calculated by the Company as adjusted funds flow less capital expenditures and is a measure of the cashflow remaining after capital expenditures that can be used for additional capital activity, repayment of debt or decommissioning expenditures. Refer below for a calculation of free adjusted funds flow.

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Adjusted funds flow	**15,555**	2,008	**29,879**	4,146
Total capital expenditures	**(10,455)**	(377)	**(27,327)**	(12,237)
Free adjusted funds flow	**5,100**	1,631	**2,552**	(8,091)

Net Debt to Quarterly Annualized EBITDA

Management considers Net Debt to Quarterly Annualized EBITDA an important measure as it is a key metric to identify the Company's ability to fund financing expenses, net debt reductions and other obligations. EBITDA should not be considered as an alternative to or more meaningful than adjusted funds flow as determined in accordance with GAAP as an indicator of the Company's performance. Quarterly Annualized EBITDA is calculated by the Company as adjusted funds flow before interest expense for the current quarter multiplied by four. This measure is consistent with the EBITDA formula prescribed under the Company's Senior Credit Facility. Net Debt to Quarterly Annualized EBITDA is calculated as Net Debt divided by Quarterly Annualized EBITDA. Refer below for a calculation of Net Debt to Quarterly Annualized EBITDA.

(thousands of dollars)	Three Months Ended September 30	
	2021	2020
Net debt	**71,331**	64,246
Adjusted funds flow	**15,555**	2,008
Interest expense (Credit Facility and other)	**1,304**	1,050
Earnings before interest, taxes and depletion ("EBITDA")	**16,859**	3,058
Quarterly annualized EBITDA	**67,436**	12,232
Net Debt to Quarterly Annualized EBITDA	**1.1**	5.2

FORWARD-LOOKING INFORMATION AND 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 expectation that the conditions to the Prairie Storm transaction described herein will be satisfied and the transaction will be completed on the terms and timing anticipated;
- the possible refinement of our 2021 capital program and anticipated changes resulting therefrom;
- management's assessment of the potential and uncertain impact of COVID-19 on the Company's operations and results;
- expectations regarding InPlay's multi-well battery at Pembina being able to accommodate all of our future development in the area over the next three years;
- the estimated time to payout of wells;
- production estimates including timing of production restart plants and the impact thereof;
- expectations regarding the business environment, industry conditions and future commodity prices;
- 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, 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).

PRODUCTION BREAKDOWN BY PRODUCT TYPE

Disclosure of production on a per boe basis in this press release consists of the constituent product types as defined in NI 51-101 and their respective quantities disclosed in the table below:

	Light and Medium Crude oil (bbls/d)	**NGLS (boe/d)**	**Conventional Natural gas (Mcf/d)**	**Total (boe/d)**
Q3 2020 Average Production	1,973	598	7,029	3,742
Q3 2020 YTD Average Production	1,976	655	7,572	3,893
Q3 2021 Average Production	3,154	663	13,166	6,011
Q3 2021 YTD Average Production	2,922	731	10,831	5,458

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