Management's Discussion and Analysis

For the years ended December 31, 2021 and 2020

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEARS ENDED DECEMBER 31, 2021 AND DECEMBER 31, 2020

The following management's discussion and analysis ("**MD&A**") is dated March 15, 2022 and should be read in conjunction with the audited consolidated financial statements of InPlay Oil Corp. ("**InPlay**" or the "**Company**") for the years ended December 31, 2021 and December 31, 2020. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") and interpretations of the IFRS Interpretations Committee.

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 and Other Financial Measures", and "Forward-Looking Information" 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 months and years ended December 31, 2021 and December 31, 2020 were as follows:

	Three months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Crude oil (bbls/d)	**3,156**	2,194	**2,981**	2,031
NGL (boe/d)	**933**	708	**782**	668
Natural gas (Mcf/d)	**15,590**	8,141	**12,030**	7,715
Total (boe/d)(1)(2)(3)	**6,687**	4,259	**5,768**	3,985
Crude oil and NGLs	**61%**	68%	**65%**	68%

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

(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 months and year ended December 31, 2021 was 57% and 45% higher respectively compared to the three months and year ended December 31, 2020, primarily as a result of the added volumes from the 2021 drilling program, reflective of the temporary production curtailments implemented by the Company throughout the second and third quarter of 2020 due to the COVID-19 pandemic and the impact of the acquisition of Prairie Storm Resources Corp. The reduced light oil and liquids weighting to 61% in the fourth quarter of 2021 and 65% during 2021 is mainly due to new production from the 2021 drilling program having a higher gas weighting.

On November 30, 2021, the Company completed a plan of arrangement (the "**Prairie Storm Arrangement**") whereby InPlay acquired all of the issued and outstanding common shares of Prairie Storm Resources Corp. ("**Prairie Storm**"), a light-oil Cardium focused producer with operations primarily in the Willesden Green area of central Alberta, for consideration of: (a) the payment of an aggregate of approximately $39.9 million in cash; and (b) the issuance of an aggregate of 8,320,335 common shares of InPlay at $1.20 per share, for total gross consideration of $49.9 million. For accounting purposes in accordance with IFRS 3, the shares issued as consideration have been valued at $2.07 per share, based on the closing price of InPlay shares on November 29, 2021. The cash portion of the consideration was funded by a combination of net proceeds released to InPlay pursuant to a $11.5 million bought deal subscription receipt financing (the "**Prairie Storm Financing**") and available borrowings under InPlay's senior credit facilities (collectively, the "**Senior Credit Facility**") which have been increased from $65.0 million to $85.0 million.

InPlay's capital program for 2021 consisted of $33.4 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 drilled two (2.0 net) ERH wells in Pembina which were brought on production in mid-October. 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. In the fourth quarter of 2021, the Company drilled two (1.6 net) ERH wells on our newly acquired Prairie Storm assets which were brought on production in 2022 January. This activity amounted to the drilling of 12 gross (10.0 net) wells for an equivalent of 20.5 gross horizontal miles (15.4 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. InPlay accelerated the start of its 2022 capital program at the end of 2021 initiating lease construction and drilling activities on a three well pad in Pembina due to optimal conditions and availability of services.

Crude oil and natural gas sales

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Crude oil	**26,124**	9,464	**85,465**	31,683
NGLs	**3,904**	1,326	**10,782**	3,784
Natural gas	**7,227**	2,039	**17,607**	6,467
Total crude oil and natural gas sales	**37,255**	12,829	**113,854**	41,934

Prices

	Three Months Ended December 31		Year Ended December 31	
Average Realized Price(1)	**2021**	2020	**2021**	2020
Crude oil ($/bbl)	**89.97**	46.88	**78.55**	42.63
NGLs ($/boe)	**45.51**	20.36	**37.79**	15.47
Natural gas ($/Mcf)	**5.04**	2.72	**4.01**	2.29
Total ($/boe)	**60.56**	32.74	**54.08**	28.75

(1) Supplementary financial measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

Throughout the later part of 2021 and into 2022, global economies have continued to recover from the COVID-19 pandemic with the easing of COVID restrictions, resulting in global crude oil demand recovering to near pre-pandemic levels. Supply has grown at a more gradual pace due to coordinated production curtailments and limited capital spending among producers. As a result, commodity prices in 2021 have significantly improved compared to 2020.

West Texas Intermediate ("WTI") prices improved in the three months and year ended December 31, 2021 compared to average prices during the three months and year ended December 31, 2020. In the fourth quarter of 2021, WTI oil prices increased 81% averaging $77.19 US per bbl compared to $42.66 US per bbl in the fourth quarter of 2020. Throughout 2021, WTI oil prices increased 72% averaging $67.91 US per bbl compared to $39.40 US per bbl during 2020.

Differentials between WTI oil prices and prices received in Alberta strengthened in the three months and year ended December 31, 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 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 $3.10 US per barrel discount for the fourth quarter of 2021 compared to $4.07 US per barrel discount for the fourth quarter of 2020. Monthly index differentials averaged $3.88 US per barrel discount for the year ended December 31, 2021 compared to $5.32 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 fourth quarter of 2021 compared to 0.77 during the fourth quarter of 2020. The Canada/US exchange rate also increased over the year ended December 31, 2021 to 0.80 compared to 0.75 throughout 2020.

Due to the items noted above, realized oil prices for the three months and year ended December 31, 2021 increased compared to the three months and year ended December 31, 2020. The Company's average net realized price for crude oil was $89.97 per bbl for the fourth quarter of 2021, 92% higher than the fourth quarter 2020 realized price of $46.88 per bbl. The Company's average net realized price for crude oil was $78.55 per bbl for year ended December 31, 2021, 84% higher than the realized price of $42.63 per bbl for the same period during 2020.

In the fourth quarter of 2021, natural gas AECO daily index prices increased 76% averaging $4.41 per GJ compared to $2.50 per GJ in the fourth quarter of 2020. During the year ended December 31, 2021, natural gas AECO daily index prices increased 63% averaging $3.44 per GJ compared to $2.11 per GJ in the year ended December 31, 2020.

The Company's average realized natural gas sales price was $5.04 per Mcf for the fourth quarter of 2021, 85% higher than the fourth quarter of 2020 realized price of $2.72 per Mcf on improved natural gas markets. The Company's average realized natural gas sales price was $4.01 per Mcf for the year ended December 31, 2021, 75% higher than the realized price of $2.29 per Mcf for the year ended December 31, 2020, also on improved natural gas markets.

Realized NGL pricing improved for the three months ended December 31, 2021 compared to the same period in 2020. The Company's average realized NGL price was $45.51 per boe for the fourth quarter of 2021, 123% higher than the fourth quarter of 2020 realized price of $20.36 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 $37.79 per boe for the year ended December 31, 2021, 144% higher than the realized price of $15.47 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 depending on commodity prices. After this period, the Crown royalties from these wells will come off this incentive period and be subject to the regular Alberta royalty structure. Recent increases to commodity prices have resulted in wells coming off of this incentive period in shorter time frames, resulting in increasing royalty rates.

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 December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Total royalties ($'000s)	**4,632**	697	**11,595**	2,924
Total royalties (% of sales)	**12.4%**	5.4%	**10.2%**	7.0%
Total royalties ($/boe)	**7.53**	1.78	**5.51**	2.00

Royalties as a percentage of revenue and on a per boe basis increased during the three months and year ended December 31, 2021 compared to the same periods in 2020 due to the effect of shorter royalty incentive periods for recently drilled wells in the improved pricing environment and 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 December 31, 2021 the Company had the following commodity-based derivative contracts outstanding.

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

Currency denomination	Volume (bbl/day)	Bought put price	Bought put premium	Term
US dollar	1,700	50.00/bbl	1.00/bbl	Jan. 1, 2022 – March 31, 2022

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	1,700	45.00/bbl	50.00/bbl	93.00/bbl	April 1, 2022 – June. 30, 2022
US dollar	1,400	45.00/bbl	50.00/bbl	100.00/bbl	July 1, 2022 – Nov. 30, 2022

(1) 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 plus 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	1,000	2.30/GJ	December 1, 2021 – March 31, 2022
Canadian dollar	2,750	3.19/GJ	April 1, 2022 – October 31, 2022

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
Canadian dollar	5,000	2.50/GJ	4.59/GJ	Jan. 1, 2022 – March 31, 2022
Canadian dollar	2,000	2.50/GJ	3.80/GJ	April 1, 2022 – June 30, 2022
Canadian dollar	2,750	2.50/GJ	3.64/GJ	April 1, 2022 – Oct. 31, 2022
Canadian dollar	5,500	2.25/GJ	4.93/GJ	Nov. 1, 2022 – Nov. 30, 2022

(2) 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.

Subsequent to December 31, 2021 the Company entered into commodity-based derivative contracts as follows:

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

Currency denomination	Volume (GJ/day)	Average swap price	Term
Canadian dollar	2,500	4.145/GJ	April 1, 2022 – October 31, 2022

The consolidated statements of profit (loss) and comprehensive income (loss) for the year ended December 31, 2021 reflected the following (losses) related to derivative contracts that were outstanding during 2021 and the comparative period for 2020.

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Realized gain (loss)	**(3,490)**	(150)	**(13,054)**	(1,203)
Unrealized gain (loss)	**3,023**	(1,224)	**974**	(1,316)
Total (loss) on derivative contracts	**(467)**	(1,374)	**(12,080)**	(2,519)

Operating expenses

	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Total operating costs ($'000s)	**7,695**	5,622	**27,009**	21,043
Total operating costs ($/boe)	**12.51**	14.35	**12.83**	14.43

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 December 31, 2021, operating expenses per boe decreased 13% to $12.51 per boe compared to $14.35 per boe for the same period in 2020. For the year ended December 31, 2021, operating expenses per boe decreased 11% to $12.83 per boe compared to $14.43 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 December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Total transportation costs ($'000s)	**673**	314	**2,346**	1,271
Total transportation costs ($/boe)	**1.09**	0.80	**1.11**	0.87

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 December 31, 2021, transportation expenses were $1.09 per boe and were higher in comparison to $0.80 per boe for the quarter ended December 31, 2020. For the year ended December 31, 2021, transportation expenses were $1.11 per boe compared and were higher in comparison to $0.87 per boe for the year ended December, 2020. Increases to oil production resulted in higher transportation rates on a per boe basis tracking increased trucking requirements for new production from wells drilled during the year in addition to 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 December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Revenue(1)	**37,255**	12,829	**113,854**	41,934
Royalties	**(4,632)**	(697)	**(11,595)**	(2,924)
Operating expenses	**(7,695)**	(5,622)	**(27,009)**	(21,043)
Transportation expenses	**(673)**	(314)	**(2,346)**	(1,271)
Operating income (2)	**24,255**	6,196	**72,904**	16,696
Sales volume (Mboe)	**615.2**	391.8	**2,105.1**	1,458.5
Per boe				
Revenue(1)	**60.56**	32.74	**54.08**	28.75
Royalties	**(7.53)**	(1.78)	**(5.51)**	(2.00)
Operating expenses	**(12.51)**	(14.35)	**(12.83)**	(14.43)
Transportation expenses	**(1.09)**	(0.80)	**(1.11)**	(0.87)
Operating netback per boe (2)	**39.43**	15.81	**34.63**	11.45
Operating income profit margin (2)	**65%**	48%	**64%**	40%

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

(2) Non-IFRS financial measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A.

Operating income and operating netback per boe in the three months and year ended December 31, 2021 increased dramatically compared to the three months and year ended December 31, 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 December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Gross G&A expenditures	**2,102**	1,774	**7,308**	5,580
Capitalized and recoveries	**(374)**	(401)	**(1,347)**	(1,093)
General and administrative expenses	**1,728**	1,373	**5,961**	4,487
G&A expenses ($/boe)	**2.81**	3.50	**2.83**	3.08
% Capitalized and recoveries	**18%**	23%	**18%**	20%

For the quarter ended December 31, 2021, G&A expenses were $1.7 million ($2.81 per boe) compared to $1.4 million ($3.50 per boe) for the same period in 2020. For the year ended December 31, 2021, G&A expenses were $6.0 million ($2.83 per boe) compared to $4.5 million ($3.08 per boe) for the same period in 2020. G&A expenses on a per boe basis were lower in the fourth quarter and throughout 2021 compared to the same periods in 2020. Improvements in G&A expenses on a per boe basis reflect costs being incurred over a larger production base. Total G&A expenses increased in the fourth quarter and throughout 2021 in comparison to the same periods in 2020, returning to normalized levels compared to the lower G&A expenses in 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 December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Share-based compensation	**803**	175	**1,699**	742
Capitalized portion	**(34)**	(42)	**(123)**	(173)
Share-based compensation expense	**769**	133	**1,576**	569

For the quarter ended December 31, 2021, share-based compensation expense was $0.8 million compared to $0.1 million for the same period in 2020. For the year ended December 31, 2021, share-based compensation expense was $1.6 million compared to $0.6 million for the same period in 2020. Share-based compensation expenses were higher in the fourth quarter and throughout 2021 compared to the same periods in 2020 due to significant improvements in the Company's share price in the later portion of 2021, resulting in additional expenses incurred from the vesting and revaluation of deferred share units, and the accelerated vesting of DSUs for one director.

During the year ended December 31, 2021, 2,059,400 options were granted, 46,800 options were exercised and 498,600 options were forfeited.

At December 31, 2021, the maximum number of stock options available for grant was 8,621,475.

Depletion and depreciation

	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Depletion and depreciation ($'000s)	**7,691**	4,801	**27,440**	20,877
Depletion and depreciation ($/boe)	**12.50**	12.25	**13.03**	14.31

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 consolidated 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 consolidated statements of profit (loss) and comprehensive income (loss) on a straight-line or declining-balance basis.

Depletion and depreciation was $7.7 million ($12.50 per boe) for the quarter ended December 31, 2021 compared to $4.8 million ($12.25 per boe) for the same period in 2020. Depletion and depreciation was $27.4 million ($13.03 per boe) for the year ended December 31, 2021 compared to $20.9 million ($14.31 per boe) for the same period in 2020. The increase on a total basis is due the higher productions volumes in the three months and year ended December 31, 2021 compared to the same periods in 2020 and the impact of the impairment reversal recorded in the second quarter of 2021.

Impairment loss

At December 31, 2021 there were indicators of impairment reversal due to significant increases in estimated future commodity prices. Impairment reversal tests were performed for the Company's West Central Alberta CGU which resulted in an impairment reversal of historical impairment charges of $3.6 million being recorded in the Company's consolidated statement of profit (loss) and comprehensive income (loss) relating to the Company's West Central Alberta CGU. 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 12%. 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.

Prior to December 31, 2021, the Company had the following CGUs: Pembina, Rocky Mountain House, Pigeon Lake, Huxley and Red Deer/Minors. Following the acquisition of Prairie Storm Resources Corp., the Company conducted an analysis of its CGUs to determine if their composition was still reflective of InPlay's core asset base and internal asset management. Following the analysis, it was determined that the previous CGUs no longer appropriately reflect InPlay's current asset base for purposes of determining impairment. Recent acquisitions and continued growth and development in concentrated areas has resulted in the Company's asset base primarily comprising liquids weighted assets in west central Alberta. Effective December 31, 2021, InPlay's CGUs were realigned into one CGU: West Central Alberta.

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 consolidated 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.

At December 31, 2021 there were no indicators of impairment relating to the Company's Exploration and evaluation assets.

Finance expenses

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Interest expense (Credit Facility and other)	**1,216**	1,375	**5,594**	3,523
Interest expense (Lease liabilities)	**4**	9	**20**	47
Accretion on decommissioning obligations	**342**	338	**1,133**	1,274
Finance expense	**1,562**	1,722	**6,747**	4,844

Finance expenses were $1.6 million for the fourth quarter of 2021, compared to $1.7 million in the fourth quarter of 2020. Finance expenses were $6.7 million for the year ended December 31, 2021, compared to $4.8 million during the same period in 2020. These increases are due to higher outstanding debt levels in the year ended December 31, 2021 compared to 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 recognized a deferred tax asset of $21.4 million at December 31, 2021. The Company recognized deferred tax recovery of $24.0 million during the year ended December 31, 2021.

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 proved cashflows and expenditures and factoring in expected corporate general and administrative and interest expenses. As a result of the increase in these future cashflows, the deferred tax asset was increased by $40.2 million as at December 31, 2021 (December 31, 2020: decreased $49.1 million) with a corresponding charge to deferred income tax recovery.

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.

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at December 31, 2021.

(thousands of dollars)		
Non-capital loss carryforward balances	$	152,699
Share issue costs		1,020
Canadian Exploration Expenses (CEE)		64,773
Canadian Development Expenses (CDE)		68,453
Canadian Oil and Gas Property Expenses (COGPE)		125,542
Undepreciated Capital Cost (UCC)		45,207
Total	$	457,694

ADJUSTED FUNDS FLOW

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Funds flow	**14,634**	3,227	**44,100**	6,834
Transactions and integration costs	**1,495**	-	**1,495**	-
Decommissioning expenditures	**1,020**	64	**1,433**	602
Adjusted funds flow(1)	**17,149**	3,291	**47,028**	7,436

(1) Capital management measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

Adjusted funds flow for the three months ended December 31 2021 was $17.1 million compared to $3.3 million for the same period in 2020. Adjusted funds flow for the year ended December 31, 2021 was $47.0 million compared to $7.4 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 months and year ended December 31, 2021 were $44.3 million and $71.6 million, respectively. The breakdown of capital expenditures is shown below:

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Land and lease	**29**	26	**71**	73
Drilling & completions	**4,779**	7,012	**26,538**	16,620
Facilities and equipping costs	**896**	3,198	**5,580**	5,498
Total exploration and development capital	**5,704**	10,236	**32,189**	22,191
Office and Capitalized G&A	**320**	397	**1,245**	943
Capital expenditures – PP&E and E&E	**6,024**	10,633	**33,434**	23,134
Property acquisitions (dispositions)	**-**	1,875	**(84)**	1,610
Net Corporate acquisitions(1)(2)	**38,287**	-	**38,287**	-
Total capital expenditures(2)	**44,311**	12,508	**71,637**	24,744

(1) This amount consists of total gross consideration of $49.9, net of $11.6 million in net working capital balances assumed on closing.

(2) Non-IFRS financial measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A.

On November 30, 2021, the Company completed a plan of arrangement (the "**Prairie Storm Arrangement**") whereby InPlay acquired all of the issued and outstanding common shares of Prairie Storm Resources Corp. ("**Prairie Storm**") a light-oil Cardium focused producer with operations primarily in the Willesden Green area of central Alberta, for consideration of: (a) the payment of an aggregate of approximately $39.9 million in cash; and (b) the issuance of an aggregate of 8,320,335 common shares of InPlay at $1.20 per share, for total gross consideration of $49.9 million. For accounting purposes in accordance with IFRS 3, the shares issued as consideration have been valued at $2.07 per share, based on the closing price of InPlay shares on November 29, 2021. The cash portion of the consideration was funded by a combination of net proceeds released to InPlay pursuant to a $11.5 million bought deal subscription receipt financing (the "**Prairie Storm Financing**") and available borrowings under InPlay's senior credit facilities (collectively, the "**Senior Credit Facility**") which have been increased from $65.0 million to $85.0 million.

InPlay's capital program for 2021 consisted of $33.4 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 drilled two (2.0 net) ERH wells in Pembina which were brought on production in mid-October. 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. In the fourth quarter of 2021, the Company drilled two (1.6 net) ERH wells on our newly acquired Prairie Storm assets which were brought on production in 2022 January. This activity amounted to the drilling of 12 gross (10.0 net) wells for an equivalent of 20.5 gross horizontal miles (15.4 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. InPlay accelerated the start of its 2022 capital program at the end of 2021 initiating lease construction and drilling activities on a three well pad in Pembina due to optimal conditions and availability of services.

Drilling statistics are shown below:

	Three months ended December 31				Year ended December 31			
	2021		2020		**2021**		2020	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**2**	**1.6**	4	3.2	**12**	**10.0**	8	7.2
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**2**	**1.6**	4	3.2	**12**	**10.0**	8	7.2
Success rate	**100%**	**100%**	100%	100%	**100%**	**100%**	100%	100%

SHARE INFORMATION

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

As of March 15, 2022, there were 86,537,351 common shares outstanding and 6,432,200 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 months and years ended December 31, 2021 and December 31, 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.

In connection with the Prairie Storm Arrangement, on November 30, 2021 the aggregate available borrowing capacity of Company's credit facility with its syndicate of lenders (the "**Senior Credit Facility**") was increased from $65.0 million to $85.0 million. The Senior Credit Facility consists of a $55 million revolving line of credit, a $10 million operating line of credit and a $20 million syndicated term facility maturing November 30, 2022 (the "**Senior Term Facility**"). The Senior Term Facility requires 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.

The revolving portion of 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 Term Facility has a maturity date of November 30, 2022 and additional advances would not be permitted and any outstanding advances would become repayable at November 30, 2022. The Senior Credit Facility is secured by a floating charge debenture of $150 million and a general security agreement on the assets of the Company. At December 31, 2021 the Company had drawn $32.9 million on the revolving portion of the Senior Credit Facility and $20 million on the Senior Term 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 December 31, 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% for the revolving portion of the Senior Credit Facility and between 5.00% and 8.50% for the Senior Term Facility. 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 portion of the Senior Credit Facility and 6.00% to 9.50% for the Senior Term Facility. 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 portion of the Senior Credit Facility is scheduled for annual renewal on May 30, 2022, 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 annual review. In the event that the lenders reduce the revolving portion of the Senior Credit Facility 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 revolving portion of the Senior Credit 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 of $150 million and a general security agreement on the assets of the Company. At December 30, 2021 the Company had drawn the full $25.0 million on the BDC Term Facility and had accrued $1.3 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 December 30, 2021 (December 31, 2020 - $0.3 million) and no additional guarantees.

In addition to the amount drawn on the Senior Credit Facilities and BDC Term Facility at December 31, 2021 the Company had a working capital deficit of $1.2 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 December 31, 2021, these obligations include:

- **Loan agreements** – The revolving portion of 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's Senior Term Facility has a maturity date of November 30, 2022 with 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. 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 December 31, 2021 were not recognized as a liability at December 31, 2021.

As at December 31, 2021 the Company had the following minimum contractual obligations:

Contractual obligations (in thousands of dollars)	2022	2023	2024	2025	2026
Accounts payable	24,669	-	-	-	-
Bank debt - principal(1)	52,863	-	25,000	-	-
Bank debt - interest(2)(3)	3,540	1,882	3,015	-	-
Bank debt – fees(4)	313	375	-	-	-
Non-cancellable office leases	297	263	-	-	-
Other leases	47	17	8	-	-
Firm service	616	400	149	84	25
Total	82,345	2,937	28,172	84	25

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

(2) Assumes interest is incurred on bank debt outstanding on the revolving portion of the Senior Credit Facility at December 31, 2021 at the Company's effective interest rate during the current quarter and the principal of the revolving portion of the Senior Credit Facility is repaid May 30, 2022 and the principal balance of the Senior Term Facility is repaid as follows: (i) $6 million by May 31, 2022; (ii) $7 million by August 31, 2022; and (iii) $7 million by November 30, 2022.

(3) Assumes interest is incurred on the BDC Term Facility outstanding at December 31, 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 audited consolidated financial statements for the years ended December 31, 2021 and December 31, 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 consolidated 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 consolidated financial statements for the years ended December 31, 2021 and December 31, 2020.

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 year ended December 31, 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. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial year end of the Company.

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. Utilizing the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") Internal Control – Integrated Framework (2013), such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial year end of the Company and concluded that the Company's internal controls over financial reporting are effective, at the financial year end of the Company. 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 October 1, 2021 and ended on December 31, 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.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, is not quantifiable at this time.

Based on the Company's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Company's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of the Company's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Company's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Our exploration and production facilities and other operations and activities emit greenhouse gasses ("GHG") which may require us to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate our effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties.

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

InPlay's focus has been concentrated on reducing debt and improving leverage ratios. Execution of this focus is significantly ahead of schedule with the increased commodity prices. With our sound financial footing and projected liquidity capacity, InPlay is expected to be able to deliver measured production per share growth and strong free adjusted funds flow[2] which positions the Company to execute on strategic accretive opportunities with the ultimate goal of maximizing returns to shareholders.

InPlay is forecasting 2022 to be another record year for the Company, and reiterates its previously announced January 12, 2022 average production guidance of 8,900 to 9,400 boe/d[1]. With the recent sustained increase in commodity prices, we are updating our price forecast using USD $90.00/bbl WTI, $4.30/mcf AECO and a CAD/USD exchange rate of 0.80. Based on this revised commodity price forecast, InPlay is now expected to generate 2022 AFF[3][4] of $141 to $150 million and 2022 FAFF[2][4] of $83 to $92 million which would result in InPlay being in a positive working capital position, in excess of debt, by year end.

Notes:

1. *See "Production Breakdown by Product Type"*
2. *Non-IFRS measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A for details of calculations, rationale for use and applicable reconciliation to the nearest IFRS measure.*
3. *Capital management measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.*
4. *See table in the Reader Advisories for key budget and underlying material assumptions related to the Company's 2022 capital program and associated guidance.*

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)	**Q4 2021**	Q3 2021	Q2 2021	Q1 2021
Oil and natural gas sales	**37,255**	31,331	25,267	20,001
Oil and natural gas sales, net of royalties	**32,623**	27,979	22,901	18,756
Profit (loss)	**55,191**	8,289	59,127	(7,536)
Profit (loss) per share, basic	**0.74**	0.12	0.87	(0.11)
Profit (loss) per share, diluted	**0.71**	0.12	0.85	(0.11)
Capital expenditures – PP&E and E&E	**6,024**	10,457	4,744	12,209
Property acquisitions/(dispositions)	**-**	(2)	(101)	19
Net Corporate acquisitions(1)	**38,287**	-	-	-
Adjusted funds flow(2)	**17,149**	15,555	8,219	6,105
Adjusted funds flow per share, basic(3)	**0.23**	0.23	0.12	0.09
Adjusted funds flow per share, diluted(3)	**0.22**	0.22	0.12	0.09
Adjusted funds flow per boe(3)	**27.87**	28.13	16.77	13.66
Net debt(2)	**80,196**	71,331	76,113	79,780

	Q4 2020	Q3 2020	Q2 2020	Q1 2020
Oil and natural gas sales	12,829	10,846	5,167	13,092
Oil and natural gas sales, net of royalties	12,132	10,056	4,639	12,183
(Loss)	(3,227)	(2,717)	(6,188)	(100,497)
(Loss) per share, basic	(0.05)	(0.04)	(0.09)	(1.47)
(Loss) per share, diluted	(0.05)	(0.04)	(0.09)	(1.47)
Capital expenditures – PP&E and E&E	10,633	382	488	11,632
Property acquisitions/(dispositions)	1,875	(5)	(260)	-
Net Corporate acquisitions(1)	-	-	-	-
Adjusted funds flow(2)	3,291	2,008	(1,279)	3,418
Adjusted funds flow per share, basic(3)	0.05	0.03	(0.02)	0.05
Adjusted funds flow per share, diluted(3)	0.05	0.03	(0.02)	0.05
Adjusted funds flow per boe(3)	8.40	5.83	(4.46)	7.85
Net debt(2)	73,681	64,246	65,487	63,713

(1) Non-IFRS financial measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A for details of calculations, rationale for use and applicable reconciliation to the nearest IFRS measure.

(2) Capital management measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

(3) Supplementary financial measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A

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.

An impairment reversal of $3.6 million was recognized in the quarter ended December 31, 2021 due to increases in estimated future commodity prices and the recoverable amount of the Company's CGUs.

On November 30, 2021, the Company completed the Prairie Storm Arrangement for consideration of: (a) the payment of an aggregate of approximately $39.9 million in cash; and (b) the issuance of an aggregate of 8,320,335 common shares of InPlay at $1.20 per share, for total gross consideration of $49.9 million. For accounting purposes in accordance with IFRS 3, the shares issued as consideration have been valued at $2.07 per share, based on the closing price of InPlay shares on November 29, 2021.

InPlay's capital program for 2021 consisted of $33.4 million of development capital, drilling 12 (10.0 net) wells during the year. This activity amounted to the drilling 12 gross (10.0 net) wells for an equivalent of 20.5 gross horizontal miles (15.4 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. InPlay accelerated the start of its 2022 capital program at the end of 2021 initiating lease construction and drilling activities on a three well pad in Pembina due to optimal conditions and availability of services.

SELECTED ANNUAL INFORMATION

Years ended December 31

(in thousands, except per share amounts)		**2021**	2020	2019
Total oil and natural gas sales[(1)]	$	**113,854**	41,934	75,025
Oil and natural gas sales, net of royalties[(1)]		**102,259**	39,010	69,198
Profit (loss)		**115,071**	(112,629)	(26,842)
Profit (loss) per share, basic		**1.65**	(1.65)	(0.39)
Profit (loss) per share, diluted		**1.61**	(1.65)	(0.39)
Total assets		**406,484**	211,035	298,006
Total bank loans		**79,127**	63,832	55,635
Total net debt[(2)]		**80,196**	73,681	55,170

(1) The oil and natural gas sales exclude realized and unrealized gains (losses) on risk management derivative contracts: 2021 excludes ($13.1 million) realized loss and $1.0 million unrealized gain; 2020 excludes ($1.2 million) realized loss and ($1.3) million unrealized loss; and 2019 excludes $0.02 million realized gain and ($0.1) million unrealized loss.

(2) Capital management measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.

ADDITIONAL INFORMATION

Additional information regarding InPlay and its business and operation, including its most recently filed annual information form, is available on the Company's profile on SEDAR at www.sedar.com. 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 AND OTHER FINANCIAL MEASURES

Throughout this MD&A and other materials disclosed by the Company, InPlay uses certain measures to analyze financial performance, financial position and cash flow. These non-GAAP and other financial measures do not have any standardized meaning prescribed under GAAP and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered alternatives to, or more meaningful than, financial measures that are determined in accordance with GAAP as indicators of the Company performance. Management believes that the presentation of these non-GAAP and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company's ongoing operating performance, and the measures provide increased transparency and the ability to better analyze InPlay's business performance against prior periods on a comparable basis.

<u>Non-GAAP Financial Measures and Ratios</u>

Included in this document are references to the terms "free adjusted funds flow", "operating income", "operating netback per boe", "operating income profit margin", "Net corporate acquisitions"and "Total capital expenditures". 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)", "adjusted funds flow", "capital expenditures", "corporate acquisitions, net of cash acquired", "net debt", "weighted average number of common shares (basic)" or assets and liabilities as determined in accordance with GAAP as a measure of the Company's performance and financial position.

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 adjusted funds flow as determined in accordance with GAAP as an indicator of the Company's performance. Free adjusted funds flow is calculated by the Company as adjusted funds flow less exploration and development capital expenditures and property dispositions (acquisitions) and is a measure of the cashflow remaining after capital expenditures before corporate acquisitions that can be used for additional capital activity, corporate acquisitions, repayment of debt or decommissioning expenditures. Refer below for a calculation of free adjusted funds flow and a reconciliation to the nearest GAAP measure, adjusted funds flow.

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Adjusted funds flow	**17,149**	3,291	**47,028**	7,436
Exploration and dev. capital expenditures	**(6,024)**	(10,633)	**(33,434)**	(23,134)
Property dispositions (acquisitions)	**-**	(1,875)	**84**	(1,610)
Free adjusted funds flow	**11,125**	(9,217)	**13,678**	(17,308)

Operating Income

Management considers operating income an important measure to evaluate its operational performance as it demonstrates its field level profitability. 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. 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. 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.

Net Corporate Acquisitions

Management considers Net corporate acquisitions an important measure as it is a key metric to evaluate the corporate acquisition in comparison to other transactions using the negotiated consideration value and ignoring changes to the fair value of the share consideration between the signing of the definitive agreement and the closing of the transaction. Net corporate acquisitions should not be considered as an alternative to or more meaningful than "Corporate acquisitions, net of cash acquired" as determined in accordance with GAAP as an indicator of the Company's performance. Net corporate acquisitions is calculated as total consideration with share consideration adjusted to the value negotiated with the counterparty, less working capital balances assumed on the corporate acquisition. Refer below for a calculation of Net corporate acquisitions and reconciliation to the nearest GAAP measure, "Corporate acquisitions, net of cash acquired".

(thousands of dollars)	Three Months Ended December 31		Year Ended December 31	
	2021	2020	**2021**	2020
Corporate acquisitions, net of cash acquired	**29,277**	-	**29,277**	-
Share consideration(1)	**9,985**	-	**9,985**	-
Non-cash working capital acquired	**(1,156)**	-	**(1,156)**	-
Derivative contracts	**181**	-	**181**	-
Net Corporate acquisitions	**38,287**	-	**38,287**	-

(1) For purposes of the corporate acquisition, the share consideration had a negotiated value of $1.20 per share. For accounting purposes in accordance with IFRS 3, the shares issued as consideration have been valued at $2.07 per share, based on the closing price of InPlay shares on November 29, 2021.

(2) Net working capital acquired equals the fair value of cash and cash equivalents, accounts receivable and accrued liabilities, prepaid expenses and deposits, inventory, accounts payable and accrued liabilities and derivative contracts acquired as disclosed in note 5 of the Company's consolidated financial statements.

Total Capital Expenditures

Management considers Total capital expenditures an important metric to measure its total capital investment compared to the Company's annual budgeted capital expenditures. Total capital expenditures is calculated as exploration and development capital expenditures plus net property acquisitions (dispositions) and net corporate acquisitions. Net corporate acquisitions should not be considered as an alternative to or more meaningful than "Capital expenditures – PP&E and E&E" as determined in accordance with GAAP as an indicator of the Company's performance. Refer to the section entitled "Capital expenditures" within this MD&A for a calculation of this measure and reconciliation to the nearest GAAP measure, "Capital expenditures – PP&E and E&E".

Capital Management Measures

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 is a GAAP measure and is disclosed in the notes to the Company's consolidated financial statements for the year ending December 31, 2021. All references to adjusted funds flow throughout this MD&A are calculated as funds flow adjusting for decommissioning expenditures and transaction and integration costs. 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 and transaction costs are non-recurring costs for the purposes of an acquisition, making the exclusion of these items relevant in Management's view to the reader in the evaluation of InPlay's operating performance. The Company also presents adjusted funds flow per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of profit (loss) per common share.

Net Debt

Net debt is a GAAP measure and is disclosed in the notes to the Company's consolidated financial statements for the year ending December 31, 2021. The Company closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. The Company uses net debt (bank debt plus accounts payable and accrued liabilities less accounts receivables and accrued receivables, prepaid expenses and deposits and inventory) as an alternative measure of outstanding debt. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

Supplementary Measures

"Average realized crude oil price" is comprised of crude oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's crude oil volumes. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"Average realized NGL price" is comprised of NGL commodity sales from production, as determined in accordance with IFRS, divided by the Company's NGL volumes. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"Average realized natural gas price" is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's natural gas volumes. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"Average realized commodity price" is comprised of commodity sales from production, as determined in accordance with IFRS, divided by the Company's volumes. Average prices are before deduction of transportation costs and do not include gains and losses on financial instruments.

"Adjusted funds flow per weighted average basic share" is comprised of adjusted funds flow divided by the basic weighted average common shares.

"Adjusted funds flow per weighted average diluted share" is comprised of adjusted funds flow divided by the diluted weighted average common shares.

"Adjusted funds flow per boe" is comprised of adjusted funds flow divided by total production.

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:

- 2022 guidance based on the planned capital program of $58 million including forecasts of 2022 annual average production levels, light oil and liquids weightings, adjusted funds flow, free adjusted funds flow, Net Debt/EBITDA ratio, operating income profit margin and growth rates;
- the possible refinement of our 2022 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;
- 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).

InPlay's 2021 annual guidance and a comparison to 2021 actual results are outlined below.

		2021 Guidance[1]	2021 Actual	Variance	Variance (%)
Production	Boe/d	5,750 – 6,000	5,768	-	-
Adjusted Funds Flow	$ millions	$51.0 - $54.0	$47.0	($5)[3]	(7%)
Capital Expenditures	$ millions	$32.5[2]	$33.4	$1[4]	3%
Free Adjusted Funds Flow	$ millions	$17.5 - $20.5	$13.6	($4)[3][4]	(20%)
Net Debt	$ millions	$76.5 - $79.5	$80.2	$1[3][4][5]	1%

Notes:

1. *As previously released September 28, 2021.*
2. *As previously released November 30, 2021 (previously $32.5 - $34.5 million on September 28, 2021).*
3. *This variance is due to the following:*
   - *Lower fourth quarter sales volumes due to operational downtime caused by extreme cold, third party processing facility mechanical shut downs, a larger build in period ending oil inventories of approximately 9,000 barrels, and the later than initially expected drilling of the two well pad drilled in the fourth quarter of 2021. In addition, new production from the 2021 drilling program had a slightly higher gas weighting and lower NGL yield than forecasted.*
   - *The effect of shorter royalty incentive periods for recently drilled wells in the improved pricing environment and higher trucking costs on new wells.*
   - *Significant improvements in the Company's share price in the later portion of 2021, resulting in additional expenses incurred from the vesting and revaluation of deferred share units, and the accelerated vesting of certain DSUs.*
   - *Increased hedging losses as a result of higher annual average WTI prices of US $1.06/bbl.*
4. *This variance is due to the acceleration of the start of the 2022 capital program at the end of 2021 through the initiation of lease construction and starting drilling activities on a three well pad in Pembina due to optimal conditions and availability of services.*
5. *This net debt variance is due to the higher positive net debt assumed on the Prairie Storm acquisition in addition to additional proceeds from the over-allotment option being exercised on the bought deal financing which both contributed to an additional $3 million positive net debt impact, net of the $4 million reduction to free adjusted funds flow.*

The key budget and underlying material assumptions used by the Company in the development of its 2022 guidance including forecasted production, operating income, capital expenditures, adjusted funds flow, free adjusted funds flow and Net Debt are as follows:

		Actuals FY 2021	Previous Guidance FY 2022[1]	Updated Guidance FY 2022
WTI	US$/bbl	$67.91	$72.50	$90.00
NGL Price	$/boe	$37.79	$42.75	$52.35
AECO	$/GJ	$3.44	$3.30	$4.30
Foreign Exchange Rate	CDN$/US$	0.80	0.78	0.80
MSW Differential	US$/bbl	$3.88	$3.50	$3.00
Production	Boe/d	5,768	8,900 – 9,400	8,900 – 9,400
Royalties	$/boe	5.51	5.25 – 5.75	9.80 – 10.60
Operating Expenses	$/boe	12.83	10.00 – 13.00	10.00 – 13.00
Transportation	$/boe	1.11	0.85 – 1.10	0.85 – 1.10
Interest	$/boe	2.67	0.85 – 1.25	0.75 – 1.15
General and Administrative	$/boe	2.83	2.00 – 2.60	2.00 – 2.60
Hedging loss	$/boe	6.20	0.00 – 0.20	0.35 – 0.65
Decommissioning Expenditures	$ millions	$1.4	$2.0 - $2.5	$2.0 - $2.5
Adjusted Funds Flow	$ millions	$47.0	$111.0 - $117.0	$141 - $150
Weighted average outstanding shares	# millions	69.8	86.2	86.2
Adjusted Funds Flow per share	$/share	0.67	1.28 – 1.36	1.64 – 1.75

		Actuals FY 2021	Previous Guidance FY 2022[1]	Updated Guidance FY 2022
Adjusted Funds Flow	$ millions	$47.0	$111.0 - $117.0	$141 - $150
Capital Expenditures	$ millions	$33.3	$58.0	$58.0
Free Adjusted Funds Flow	$ millions	$13.6	$53.5 - $59.5	$83 - $92

(1) As previously released January 12, 2022.

- See "Production Breakdown by Product Type" below
- Quality and pipeline transmission adjustments may impact realized oil prices in addition to the MSW Differential provided above
- Changes in working capital are not assumed to have a material impact between Dec 31, 2021 and Dec 31, 2022.

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 (bbls/d)	Conventional Natural gas (Mcf/d)	Total (boe/d)
Q4 2020 Average Production	2,194	708	8,141	4,259
2020 Average Production	2,031	668	7,715	3,985
Q4 2021 Average Production	3,156	933	15,590	6,687
2021 Average Production	2,981	782	12,030	5,768
2022 Annual Guidance	4,332	1,312	21,035	9,150[1]

Notes:

1. *This reflects the mid-point of the Company's 2022 production guidance range of 8,900 to 9,400 boe/d.*
2. *With respect to forward-looking production guidance, product type breakdown is based upon management's expectations based on reasonable assumptions but are subject to variability based on actual well results.*

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