Management's Discussion and Analysis

For the three months ended March 31, 2021

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 2021 AND MARCH 31, 2020

The following management's discussion and analysis ("**MD&A**") is dated May 5, 2021 and should be read in conjunction with the unaudited financial statements of InPlay Oil Corp. ("**InPlay**" or the "**Company**") for the three months ended March 31, 2021 and March 31, 2020 and the audited annual financial statements for the years ended December 31, 2020 and December 31, 2019. The financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") and interpretations of the IFRS Interpretations Committee, applicable to the preparation of interim financial statements, including IAS 34, Interim Financial Reporting.

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

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

ABOUT INPLAY

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

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

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

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

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

REVIEW OF FINANCIAL RESULTS

Production

Average production volumes for the three months ended March 31, 2021 and March 31, 2020 were as follows:

	Three Months Ended March 31	
	2021	2020
Crude oil (bbls/d)	**2,665**	2,432
NGL (boe/d)	**802**	807
Natural gas (Mcf/d)	**8,994**	9,271
Total (boe/d) (1)(2)(3)	**4,965**	4,784

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

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

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

Production for the three months ended March 31, 2021 was 4% higher compared to the three months ended March 31, 2020, primarily as a result of the added volumes from the drilling program during the fourth quarter of 2020.

InPlay's capital program for the first quarter of 2021 consisted of $12.2 million of development capital. The Company drilled three (3.0 net) extended reach horizontal ("ERH") wells in Pembina and completed one (0.2 net) non-operated Nisku ERH well during the three months ended March 31, 2021, amounting to an equivalent of 4.5 gross horizontal miles (4.5 net horizontal miles). This capital spending also included the construction of a multi-well battery in Pembina which is anticipated to accommodate all of our future development of the area over the next three years.

Crude oil and natural gas sales

(thousands of dollars)	Three Months Ended March 31	
	2021	2020
Crude oil	**15,270**	10,412
NGLs	**2,123**	942
Natural gas	**2,608**	1,738
Total crude oil and natural gas sales	**20,001**	13,092

Prices

	Three Months Ended March 31	
	2021	2020
Crude oil ($/bbl)	**63.67**	47.04
NGLs ($/boe)	**29.43**	12.84
Natural gas ($/Mcf)	**3.22**	2.06
Total ($/boe)	**44.76**	30.07

West Texas Intermediate ("WTI") prices improved in the three months ended March 31, 2021 compared to average prices during the three months ended March 31, 2020. In the first quarter of 2021, WTI oil prices increased 25% averaging $57.84 US per bbl compared to $46.17 US per bbl in the first quarter of 2020.

Differentials between WTI oil prices and prices received in Alberta strengthened in the first quarter of 2021 and compared to the first quarter of 2020. These differentials are volatile due to factors including refining demand and pipeline capacity. InPlay sells its oil at monthly average Edmonton Par prices less quality differentials, transportation and marketing fees. Light, sweet oil differentials between Cushing, Oklahoma and Edmonton, Alberta are affected by pipeline apportionment, refinery turnarounds, rail capacity and market supply/demand conditions. Monthly index differentials averaged $5.24 US per barrel discount for the first quarter of 2021 compared to $7.58 US per barrel discount for the first quarter of 2020.

Realized oil prices are adjusted for the Canada/US exchange rate which increased averaging 0.79 for the first quarter of 2021 compared to 0.74 during the first quarter of 2020.

Due to the items noted above, realized oil prices for the three months ended March 31, 2021 increased compared to the three months ended March 31, 2020. The Company's average net realized price for crude oil was $63.67 per bbl for the first quarter of 2021, 35% higher than the first quarter 2020 realized price of $47.04 per bbl.

In the first quarter of 2021, natural gas AECO daily index prices increased 55% averaging $2.99 per GJ compared to $1.93 per GJ in the first quarter of 2020.

The Company's average realized natural gas sales price was $3.22 per Mcf for the three months ended March 31, 2021, 56% higher than the first quarter of 2020 realized price of $2.06 per Mcf on improved natural gas markets.

Realized NGL pricing improved for the three months ended March 31, 2021 compared to the same period in 2020. The Company's average realized NGL sales price was $29.43per boe for the first quarter of 2021, 129% higher than the first quarter of 2020 realized price of $12.84 per boe as a result of improved ethane, propane and butane markets.

Royalties

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

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

	Three Months Ended March 31	
	2021	2020
Total royalties ($'000s)	**1,245**	909
Total royalties (% of sales)	**6.2%**	6.9%
Total royalties ($/boe)	**2.79**	2.09

Lower posted par prices by the government of Alberta during the three months ended March 31, 2021 in comparison to the three months ended March 31, 2020 resulted in lower royalty rates on a percentage of revenue basis. Increases to oil production as a percentage of total production resulted in higher royalty rates on a per boe basis given the higher royalties incurred on oil production.

Derivative contracts

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

At March 31, 2021 the Company had the following commodity-based derivative contracts outstanding.

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

Currency denomination	Volume (bbl/day)	Average swap price	Term
US dollar	250	42.52/bbl	December 1, 2020 – June 30, 2021
US dollar	1,250	45.88/bbl	January 1, 2021 – June 30, 2021
Canadian dollar	250	65.00/bbl	February 1, 2021 – December 31, 2021

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

Currency denomination	Volume (bbl/day)	Bought put price	Sold call price	Term
US dollar	250	34.50/bbl	50.15/bbl	Jan 1, 2021 – June 30, 2021
US dollar	250	52.00/bbl	69.00/bbl	July 1, 2021 – Dec. 31, 2021

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

Type of contract: three-way collar[2] (crude oil pricing WTI):

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

(2) The WTI three-way collars are a combination of a sold call, bought put and a sold put. The sold put price is the maximum the Company will receive for the contract volumes. The sold call price is the minimum price InPlay will receive, unless the market price falls below the bought put strike price.

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

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

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

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

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

At March 31, 2021 the Company had the following forward exchange rate contracts outstanding.

Type of contract: swap (USD/CAD):

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

The statements of (loss) and comprehensive (loss) for the three months ended March 31, 2021 reflected the following gains/(losses) related to derivative contracts that were outstanding during 2021 and the comparative period for 2020.

(thousands of dollars)	Three Months Ended March 31	
	2021	2020
Realized (loss)	**(3,045)**	-
Unrealized (loss)	**(2,230)**	-
Total (loss) on derivative contracts	**(5,275)**	-

Operating expenses

	Three Months Ended March 31	
	2021	2020
Total operating costs ($'000s)	**6,422**	6,386
Total operating costs ($/boe)	**14.37**	14.67

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 March 31, 2021, operating expenses per boe decreased slightly to $14.37 per boe compared to $14.67 per boe for the same period in 2020. Although operating costs remained unchanged at $6.4 million in the first quarter of 2021 compared to the first quarter of 2020 and decreased to $14.37 per boe from $14.67 per boe, operating expenses were also negatively impacted during the first quarter of 2021 due to the impact of extremely cold weather which will cause higher operating costs through more difficult operations, the impact of higher power costs as a result of extreme power demand placed on the electrical grid system through the winter months and unexpected turnaround activity. In addition, higher natural gas pricing and the extremely cold weather increased the heating and fuel costs of our operations during the first quarter.

Transportation expenses

	Three Months Ended March 31	
	2021	2020
Total transportation costs ($'000s)	**418**	345
Total transportation costs ($/boe)	**0.94**	0.79

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 March 31, 2021, transportation expenses were $0.94 per boe and were higher in comparison to $0.79 per boe for the quarter ended March 31, 2020. Increases to oil production as a percentage of total production resulted in higher transportation rates on a per boe basis given the higher transportation costs incurred on oil production.

Operating Income and Netback

(thousands of dollars)	Three Months Ended March 31	
	2021	2020
Revenue[1]	**20,001**	13,092
Royalties	**(1,245)**	(909)
Operating expenses	**(6,422)**	(6,386)
Transportation expenses	**(418)**	(345)
Operating income [2]	**11,916**	5,452
Sales volume (Mboe)	**446.9**	435.4
Per boe		
Revenue[1]	**44.76**	30.07
Royalties	**(2.79)**	(2.09)
Operating expenses	**(14.37)**	(14.67)
Transportation expenses	**(0.94)**	(0.79)
Operating netback per boe [2]	**26.66**	12.52
Operating income profit margin [2]	**60%**	42%

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

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

Operating income and operating netback per boe in the three months ended March 31, 2021 increased dramatically compared to the three months ended March 31, 2020 reflecting the 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 March 31	
	2021	2020
Gross G&A expenditures	**1,452**	1,715
Capitalized and recoveries	**(363)**	(330)
General and administrative expenses	**1,089**	1,385
G&A expenses ($/boe)	**2.44**	3.18
% Capitalized and recoveries	**25%**	19%

For the quarter ended March 31, 2021, G&A expenses were $1.1 million ($2.44 per boe) compared to $1.4 million ($3.18 per boe) for the same period in 2020. G&A expenses decreased in the first quarter of 2021 on a total and per boe basis in comparison to the first quarter of 2020 due to continued lower cost after the cost cutting measures and compensation expense reductions implemented by the Company in response to the COVID-19 pandemic.

Share-based compensation expenses

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

(thousands of dollars)	Three Months Ended March 31	
	2021	2020
Share-based compensation	**317**	212
Capitalized portion	**(30)**	(46)
Share-based compensation expense	**287**	166

During the quarter ended March 31, 2021, 1,042,900 options and 617,650 deferred share units ("DSUs") were granted.

At March 31, 2021, the maximum number of stock options available for grant was 6,825,662.

Depletion and depreciation

	Three Months Ended March 31	
	2021	2020
Depletion and depreciation ($'000s)	**5,734**	7,433
Depletion and depreciation ($/boe)	**12.83**	17.07

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

Depletion and depreciation was $5.7 million ($12.83 per boe) for the quarter ended March 31, 2021 compared to $7.4 million ($17.07 per boe) for the same period in 2020. The decrease on a total and per boe basis is due to the impairment of Property, plant and equipment recognized at March 31, 2020 which resulted in lower net book values subject to depletion without a corresponding reduction in proved plus probable reserves.

Impairment

At March 31, 2021 there were no indicators of impairment or impairment reversal relating to the Company's Property, plant and equipment assets.

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

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

Exploration and evaluation expense

During the three months ended March 31, 2021, the Company recognized $5.4 million in Exploration and evaluation expense relating to anticipated near term undeveloped land lease expiries.

Finance expenses

(thousands of dollars)	Three Months Ended March 31	
	2021	2020
Interest expense (Credit Facility and other)	**1,477**	633
Interest expense (Lease liabilities)	**7**	16
Accretion on decommissioning obligations	**165**	308
Finance expense	**1,649**	957

Finance expenses were $1.6 million for the first quarter of 2021, compared to $1.0 million in the first quarter of 2020.

Income taxes

The Company has not recognized a deferred tax asset at March 31, 2021. The Company recognized deferred tax expense of $nil during the quarter ended March 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 decrease in these future cashflows, the deferred tax asset was reduced by $1.7 million as at March 31, 2021 (March 31, 2020: $43.7 million) with a corresponding charge to deferred income tax expense.

During the quarter ended June 30, 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12% to 8% over four years. The tax rate decrease will be phased in as follows: 11% effective July 1, 2019, 10% effective January 1, 2020, 9% effective January 1, 2021, and 8% effective January 1, 2022. During the quarter ended September 30, 2020, this tax rate decrease was accelerated to 8% effective July 1, 2020. This rate change results in decreased future value attributable to the Company's unused tax losses and temporary differences. As a result, the Company recognized a reduction to its deferred tax asset and a deferred income tax expense of $1.4 million during the three months ended March 31, 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 March 31, 2021.

Non-capital loss carryforward balances	$	122,508
Share issue costs		851
Canadian Exploration Expenses (CEE)		64,773
Canadian Development Expenses (CDE)		67,714
Canadian Oil and Gas Property Expenses (COGPE)		110,118
Undepreciated Capital Cost (UCC)		49,896
Total	$	415,860

FUNDS FLOW AND ADJUSTED FUNDS FLOW

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

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

(thousands of dollars)	Three Months Ended March 31	
	2021	2020
Funds flow	**6,093**	3,235
Decommissioning expenditures	**12**	183
Adjusted funds flow(1)	**6,105**	3,418

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

Funds flow for the three months ended March 31, 2021, was $6.1 million compared to $3.2 million for the same period in 2020. Adjusted funds flow for the three months ended March 31, 2021 was $6.1 million compared to $3.4 million for the same period in 2020. These changes are reflective of the changes to benchmark prices realized during the respective periods.

CAPITAL EXPENDITURES

Capital expenditures for the three months ended March 31, 2021 were $12.2 million. The breakdown of capital expenditures is shown below:

(thousands of dollars)	Three Months Ended March 31	
	2021	2020
Land and lease	**22**	22
Drilling & completions	**9,196**	9,179
Facilities and equipping costs	**2,608**	2,147
Total exploration and development capital	**11,826**	11,348
Office and Capitalized G&A	**383**	284
Total	**12,209**	11,632
Net Property Acquisitions(1)	**19**	-
Total capital expenditures	**12,228**	11,632

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

InPlay's capital program for the first quarter of 2021 consisted of $12.2 million of development capital. The Company drilled three (3.0 net) extended reach horizontal ("ERH") wells in Pembina and completed one (0.2 net) non-operated Nisku ERH well during the three months ended March 31, 2021, amounting to an equivalent of 4.5 gross horizontal miles (4.5 net horizontal miles). This capital spending also included the construction of a multi-well battery in Pembina which is anticipated to accommodate all of our future development of the area over the next three years.

Drilling statistics are shown below:

	Three Months Ended March 31			
	2021		2020	
	Gross	**Net**	Gross	Net
Crude oil	**3.0**	**3.0**	4.0	4.0
Natural gas	**-**	**-**	-	-
Dry	**-**	**-**	-	-
Total	**3.0**	**3.0**	4.0	4.0
Success rate	**100%**	**100%**	100%	100%

SHARE INFORMATION

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

As of May 5, 2021, there were 68,256,616 common shares outstanding and 6,355,700 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 ended March 31, 2021 and March 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.

On July 14, 2020, the Company entered into an Amended and Restated Credit Agreement ("ARCA") with its syndicate of lenders. The Company's amended credit facilities (the "Senior Credit Facilities") total $65 million and consist of a $22.5 million revolving line of credit, a $10 million operating line of credit (together, the "Revolving Facilities") and a $32.5 million term loan (the "Senior Term Loan"). The Senior Term Loan has a maturity date of May 31, 2021. The Revolving Facilities have a maturity date of May 31, 2021, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable at May 31, 2021. The Senior Credit Facilities are secured by a floating charge debenture and a general security agreement on the assets of the Company. At March 31, 2021 the Company had drawn $44.2 million on the Senior Credit Facilities. There are standard reporting covenants under the Senior Credit Facilities, however there are no financial covenants. The Company was in compliance with these standard reporting covenants as at March 31, 2021.

Under the ARCA, advances can be drawn as prime rate loans and bear interest at the bank's prime lending rate plus interest rates between 2.00% and 5.50% for the Revolving Facilities and between 5.00% and 8.50% for the Senior Term Loan. Advances may also be drawn as banker's acceptances, Libor loans, and letters of credit, subject to Canadian interest benchmark rates plus margins ranging from 3.00% to 6.50% for the revolving line of credit and 6.00% to 9.50% for the Senior Term Loan. Standby fees are charged on the undrawn portion of the Senior Credit Facilities at rates ranging from 0.750% to 1.625%. These interest rates, fees and margins vary based on adjusted debt to earnings metrics determined at each quarter end for the preceding 12 months.

The available lending limit of the Revolving Facilities is scheduled for annual renewal on May 31, 2021, 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 Facilities will not be adjusted at the next annual review. In the event that the lenders reduce the Revolving Facilities' borrowing base below the amount drawn at the time of the redetermination, the Company would have 60 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

On October 30, 2020 the Company entered into a term loan with the Business Development Bank of Canada ("BDC") under their Business Credit Availability Program ("BCAP") which provided the Company with a non-revolving $25 million, second lien, four year term loan facility (the "BDC Term Facility"). The BDC Term Facility has a maturity date of October 30, 2024 and is secured by a floating charge debenture and a general security agreement on the assets of the Company. At March 31, 2021 the Company had drawn the full $25.0 million on the BDC Term Facility and had accrued $0.5 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 March 31, 2021 (December 31, 2020 - $0.3 million).

In addition to the amount drawn on the Senior Credit Facilities and BDC Term Facility at March 31, 2021, the Company had a working capital deficit of $10.1 million. The Company had a higher level of current liabilities due to the Company's drilling program during the first quarter of 2021.

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 March 31, 2021, these obligations include:

- **Loan agreement** – On July 14, 2020, the Company's Credit Facility was amended to include a $32.5 million Term Loan with a maturity date of May 31, 2021 and a $32.5 million revolving line of credit that, if not extended, any outstanding balances would become repayable on May 31, 2021. The Company 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 March 31, 2021 were not recognized as a liability at March 31, 2021.

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

Contractual obligations (in thousands of dollars)	Payments due by year 2021	2022	2023	2024	2025	Thereafter
Accounts payable	21,606	-	-	-	-	-
Bank debt - principal[1]	44,170	-	-	25,000	-	-
Bank debt - interest[2][3]	902	1,687	2,095	3,348	-	-
Non-cancellable office leases	283	31	-	-	-	-
Other leases	92	50	17	8	-	-
Firm service	201	233	189	137	71	21
Total	67,254	2,001	2,301	28,493	71	21

(1) Assumes the Senior Credit Facilities are not renewed on May 31, 2021, whereby outstanding balances become due on May 31, 2021 and the BDC Term Facility is payable on October 30, 2024.

(2) Assumes interest is incurred on bank debt outstanding on the Senior Credit Facilities at March 31, 2021 at the Company's effective interest rate during the current quarter and the principal balance of the Senior Credit Facilities is repaid on May 31, 2021.

(3) Assumes interest is incurred on the BDC Term Facility outstanding at March 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.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 3 to the Company's unaudited interim financial statements for the three months ended March 31, 2021. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results than reported. The Company's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results that differ materially from current estimates.

Oil and natural gas reserves

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

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

Recoverable amounts of CGUs

The recoverable amount of a CGU used in the assessment of impairment is the greater of its value-in-use ("**VIU**") and its fair value less costs to sell ("**FVLCTS**"). VIU is determined by estimating the present value of the future net cash flows from the continued use of the CGU, and is subject to the risks associated with estimating the value of reserves. FVLCTS refers to the amount obtainable from the sale of a CGU in an arm's length transaction between knowledgeable, willing parties, less costs of disposal. The criteria used in the estimation of this amount are discussed in note 4 to the audited annual financial statements for the years ended December 31, 2020 and December 31, 2019.

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

Decommissioning obligations

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

Income taxes

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

CHANGES IN ACCOUNTING POLICIES

There were no new or amended accounting standards or interpretations adopted in the three months ended March 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.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on January 1, 2021 and ended on March 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 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 timing 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 distribution of an effective vaccine also continues to raise uncertainty.

Oil and natural gas exploration and production is capital intensive and involves a number of business risks including, without limitation, the uncertainty of finding new reserves, the instability of commodity prices, weather, and various operational risks. Commodity prices are influenced by local and worldwide supply and demand, OPEC actions, ongoing global economic concerns, the US dollar exchange rate, transportation costs, political stability, the continuing impact of COVID-19 and travel bans and seasonal and weather-related changes to demand. The concern over increasing US natural gas production, driven primarily by the US shale gas plays, continues to depress the natural gas futures market. Oil prices declined sharply in the latter part of 2015 and continue to remain volatile as oil is a geopolitical commodity, affected by concerns about global economic markets, continued instability in oil producing countries and increases in production from US tight oil plays. Differentials between WTI oil prices and prices received in Alberta are volatile. The industry is subject to extensive governmental regulation with respect to the environment. Over the past number of years, several new environmental regulations at both the Federal and Provincial level were announced, though the details of how some of the regulations will be implemented have yet to be released. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain and maintain drilling licenses and other regulatory approvals, ability to obtain equipment, expiration of licenses and leases, competition from other producers, third-party transportation and processing disruption issues, sufficiency of insurance, ability to manage growth, reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These additional risks are described in more detail in the Company's most recent AIF filed with certain Canadian securities regulatory authorities on SEDAR at www.sedar.com.

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

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

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

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

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

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

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

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

OUTLOOK

The commodity price recovery in the past year has been remarkable and occurred quicker than InPlay and most in the industry expected. We are pleased to report that InPlay is ahead of schedule on our road to recovery, already reaching our goal of quickly returning to 2019 pre-COVID production levels of 5,000 boe/d. The Company is on track to generate record levels of production and AFF in 2021 resulting in substantial Free Adjusted Funds Flow ("FAFF")(2) to pay down the increase in debt that occurred in 2020. InPlay is on a faster pace than anticipated to achieve a target of one times Net Debt/EBITDA(2). This is in addition to achieving a record level of reserves in all categories as at December 31, 2020. All of these accomplishments were achieved without share dilution and places InPlay in the strongest position we have ever been to execute our strategy of top tier light oil growth per share and strong FAFF. We are excited that with increased financial flexibility, we have the option of reducing debt levels and exploring accretive acquisition opportunities such as our last acquisition in the fourth quarter of 2020.

The three 1.5 mile ERH Pembina wells drilled during the quarter are performing exceptionally well, are in the early post-completion clean-up stage and produced at a combined rate of approximately 890 boe/d (75% light oil; 5% NGLs) over the first 30 days ("IP 30") based on field estimates. These rates significantly exceed both our internal forecasted production volumes and those assigned in our 2020 year end reserve report. Performance to date on these ERH wells, while early, is similar to our previous six wells drilled in Pembina, which now have up to one and a half years of production history. These previously drilled wells exceeded our internal forecasted average initial production ("IP") 365 day rate by approximately 43% on average and produced at a higher oil weighting than the Company average. This was achieved despite these wells being temporarily curtailed in the second and third quarter of 2020 due to the historically low commodity prices caused by the COVID-19 demand destruction. We are extremely enthused by the positive results achieved from the Cardium drilling program in Pembina and look forward to the continued development of the assets acquired in the October 2020 strategic acquisition.

Based on the consistent performance of the Pembina assets and the recent results, the Company continues to refine our 2021 drilling program. Currently, while the total number of wells planned in 2021 remains unchanged, InPlay expects to shift focus towards the Pembina area, accessing the completed Pembina multi-well battery built in the first quarter. The revised program would initially target wells directly offsetting the successful first quarter 2021 Pembina wells mid-year, subject to spring breakup conditions and the availability of equipment and services.

At this time, InPlay reiterates its guidance for 2021 of estimated annual average production of 5,100 to 5,400 boe/d(1)(3) (69% light oil & NGLs), representing annual organic production growth of approximately 28% to 35% over 2020 levels. The Company is forecasting a 2021 operating income profit margin(2)(3) of approximately 64% and a net debt to 2021 EBITDA[2][3] of 1.3 – 1.5 times at year end. Solid operational results exiting the first quarter along with stable commodity pricing that has trended higher, combined with the termination of punitive hedges at the end of the second quarter (which were put in place in 2020 to protect the balance sheet and capital program), are very positive catalysts for InPlay's future success. We are very excited about the remainder of 2021 which is anticipated to be a record year for the Company based on our forecast for financial and operational results.

Notes:

1. *See " Production Breakdown by Product Type"*
2. *"AFF", "FAFF", "Net Debt/EBITDA" and "operating income profit margin" are Non-IFRS Measures and do not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and may not be comparable with the calculations of similar measures for other companies. Please refer to the section entitled "Non-GAAP Measures" for details of calculations, rationale for use and applicable reconciliation to the nearest IFRS measure.*
3. *Please refer to section entitled 'Forward-looking Information and Statements' for key budget and underlying material assumptions related to the Company's 2021 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)	**Q1 2021**	Q4 2020	Q3 2020	Q2 2020
Oil and natural gas sales	**20,001**	12,829	10,846	5,167
Oil and natural gas sales, net of royalties	**18,756**	12,132	10,056	4,639
(Loss)	**(7,536)**	(3,227)	(2,717)	(6,188)
(Loss) per share, basic and diluted	**(0.11)**	(0.05)	(0.04)	(0.09)
Exploration and development capital expenditures	**12,209**	10,633	382	488
Property acquisitions/(dispositions)	**19**	1,875	(5)	(260)
Funds flow	**6,093**	3,227	1,768	(1,395)
Adjusted funds flow[1]	**6,105**	3,291	2,008	(1,279)
Adjusted funds flow per share, basic and diluted[1]	**0.09**	0.05	0.03	(0.02)
Adjusted funds flow per boe[1]	**13.66**	8.40	5.83	(4.46)
Net debt	**79,780**	73,681	64,246	65,487

	Q1 2020	Q4 2019	Q3 2019	Q2 2019
Oil and natural gas sales	13,092	18,425	17,395	19,995
Oil and natural gas sales, net of royalties	12,183	17,357	15,737	18,386
(Loss)	(100,497)	(18,892)	(1,355)	(7,629)
(Loss) per share, basic and diluted	(1.47)	(0.28)	(0.02)	(0.11)
Exploration and development capital expenditures	11,632	4,574	8,082	4,688
Property acquisitions/(dispositions)	-	14	-	(9)
Funds flow	3,235	7,592	6,397	8,461
Adjusted funds flow[1]	3,418	7,846	6,886	8,755
Adjusted. funds flow per share, basic and diluted[1]	0.05	0.11	0.10	0.13
Adjusted funds flow per boe[1]	7.85	17.06	14.73	18.58
Net debt	63,713	55,170	58,053	56,304

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

InPlay's 2019 capital program consisted of $32.1 million of development capital focused in the Willesden Green and Pembina Cardium areas. The Company drilled 10 (5.2 net) extended reach horizontal ("ERH") wells and three (3.0 net) one-mile horizontal wells during the year ended December 31, 2019, amounting to an equivalent of 22 gross horizontal miles (11.8 net horizontal miles) and completed two (2.0 net) ERH wells that were drilled in the fourth quarter of 2018.

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

InPlay's 2020 capital program consisted of $23.1 million of development capital. The Company drilled four (4.0 net) extended reach horizontal ("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.

InPlay's capital program for the first quarter of 2021 consisted of $12.2 million of development capital. The Company drilled three (3.0 net) extended reach horizontal ("ERH") wells in Pembina and completed one (0.2 net) non-operated Nisku ERH well during the three months ended March 31, 2021, amounting to an equivalent of 4.5 gross horizontal miles (4.5 net horizontal miles). This capital spending also included the construction of a multi-well battery in Pembina which is anticipated to accommodate all of our future development of the area over the next three years.

SELECTED ANNUAL INFORMATION

Years ended December 31

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

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

ADDITIONAL INFORMATION

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

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

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

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

NON-GAAP MEASURES

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

Adjusted Funds Flow

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

Adjusted Funds Flow per Share, Basic and Diluted

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

	Three Months Ended March 31	
	2021	2020
Adjusted funds flow ($000s)	**6,105**	3,418
Weighted avg. number of common shares (basic and diluted ('000s))	**68,257**	68,257
Adjusted funds flow per share, basic and diluted	**0.09**	0.05

Adjusted Funds Flow per boe

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

	Three Months Ended March 31	
	2021	2020
Adjusted funds flow ($000s)	**6,105**	3,418
Sales volume (Mboe)	**446.9**	435.4
Adjusted funds flow per boe	**13.66**	7.85

Free Adjusted Funds Flow

Management considers free adjusted funds flow an important measure to identify the Company's ability to improve its financial condition through debt repayment, which has become more important recently with the introduction of second lien lenders. Free adjusted funds flow should not be considered as an alternative to or more meaningful than funds flow as determined in accordance with GAAP as an indicator of the Company's performance. InPlay's determination of free adjusted funds flow may not be comparable to that reported by other companies. Free adjusted funds flow is calculated by the Company as adjusted funds flow less capital expenditures and is a measure of the cashflow remaining after capital expenditures that can be used for additional capital activity, repayment of debt or decommissioning expenditures. Refer to "Forward Looking Information and Statements" section for a calculation of forecast free adjusted funds flow.

Operating Income

Management considers operating income an important measure to evaluate its operational performance as it demonstrates its field level profitability. Operating income should not be considered as an alternative to or more meaningful than net income as determined in accordance with GAAP as an indicator of the Company's performance. InPlay's determination of operating income may not be comparable to that reported by other companies. Operating income is calculated by the Company as oil and natural gas sales less royalties, operating expenses and transportation expenses and is a measure of the profitability of operations before administrative, share-based compensation, financing and other non-cash items. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure and a reconciliation to the nearest GAAP measure.

Operating Netback per BOE

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

Operating Income Profit Margin

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

Net Debt/EBITDA

Management considers Net Debt/EBITDA an important measure as it is a key metric under our first lien and second lien credit facilities and is an important measure to identify the Company's annual ability to fund financing expenses, net debt reductions and other obligations. EBITDA should not be considered as an alternative to or more meaningful than funds flow as determined in accordance with GAAP as an indicator of the Company's performance. EBITDA is calculated by the Company as adjusted funds flow before interest expense. This measure is consistent with the EBITDA formula prescribed under the Company's Credit Facility. Net Debt/EBITDA is calculated as Net Debt divided by EBITDA. Refer to "Forward Looking Information and Statements" section for a calculation of forecast Net Debt/EBITDA.

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:

- 2021 guidance based on the planned capital program of $23 million including forecasts of 2021 annual average production levels, light oil and liquids weightings, funds flow, adjusted funds flow, free adjusted funds flow, Net Debt/EBITDA ratio, operating income profit margin and growth rates;
- our estimate that our 2021 capital program is anticipated to result in a record year of production and AFF, resulting in substantial FAFF which can be used to repay debt forecasted spending on decommissioning;
- the possible refinement of our 2021 capital program and anticipated changes resulting therefrom;
- management's assessment of the potential and uncertain impact of COVID-19 on the Company's operations and results;
- the estimated time to payout of wells;
- production estimates including timing of production restart plants and the impact thereof;
- expectations regarding the business environment, industry conditions and future commodity prices;
- InPlay's business strategy, goals and management focus;
- sources of funds for the Company's operations, capital expenditures and decommissioning obligations;
- future liquidity and the Company's access to sufficient debt and equity capital;
- the resource potential of InPlay's asset base and future prospects for development and growth;
- future costs, expenses and royalty rates;
- the volume and product mix of InPlay's oil and gas production;

- future exchange rate between the $US and $Cdn
- expectations regarding InPlay's tax horizon;
- capital management strategies;
- the timing and impact of new accounting policies and standards; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

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

These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond InPlay's control. Such risks and uncertainties include, without limitation: the impact of general economic conditions; volatility in market prices for crude oil and natural gas; the impact of COVID-19; industry conditions; currency fluctuations; imprecision of reserve estimates; liabilities inherent in crude oil and natural gas operations; environmental risks; incorrect assessments of the value of acquisitions and exploration and development programs; competition from other producers; the lack of availability of qualified personnel, drilling rigs or other services; changes in income tax laws or changes in royalty rates and incentive programs relating to the oil and natural gas industry; hazards such as fire, explosion, blowouts, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; and ability to access sufficient capital from internal and external sources.

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

The key budget and underlying material assumptions used by the Company in the development of its planned 2021 capital program and associated guidance including forecasted 2021 production, funds flow, adjusted funds flow, free adjusted funds flow, Net Debt, Net Debt/EBITDA ratio and operating income profit margin are as follows:

		Current Guidance FY 2021(1)
WTI	US$/bbl	$60.50
NGL Price	$/boe	$27.30
AECO	$/GJ	$2.60
Foreign Exchange Rate	(US$/CDN$)	0.79
MSW Differential	US$/bbl	$4.00
Production	Boe/d	5,100 – 5,400
Royalties	$/boe	3.90 - 4.50
Operating Expenses	$/boe	11.50 - 13.50
Transportation	$/boe	0.80 - 0.90
Interest	$/boe	2.25 - 2.75
General and Administrative	$/boe	2.60 - 3.10
Hedging (gain)/loss	$/boe	3.75 – 4.25
Capital Expenditures	$ millions	$23
Decommissioning Expenditures	$ millions	$1.3 - $1.5
Net Debt	$ millions	$58.0 - $61.0
Forecasted Adjusted Funds Flow	$ millions	$39.0 - $42.0
Forecasted Funds Flow	$ millions	$37.5 - $40.5

		Current Guidance FY 2021(1)
Forecasted Adjusted Funds Flow	$ millions	$39.0 - $42.0
Capital Expenditures	$ millions	$23
Forecasted Free Adjusted Funds Flow	$ millions	$15.0 - $18.0

		Current Guidance FY 2021(1)
Forecasted Adjusted Funds Flow	$ millions	$39.0 - $42.0
Interest	$/boe	2.25 - 2.75
EBTIDA	$ millions	$43.0 - $46.0
Net Debt	$ millions	$58.0 - $61.0
Net Debt/EBITDA		1.3 – 1.5

1. *The above guidance and underlying assumptions are consistent with that previously released March 16, 2021.*

- Forecasted production breakdown is as follows: light oil - 56%, natural gas liquids - 13%, natural gas – 31%. 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, 2020 and Dec 31, 2021

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)
Q1 2020 Average Production	2,432	807	9,271	4,784
2020 Average Production	2,031	668	7,715	3,985
Q1 2021 Average Production	2,665	802	8,994	4,965
2021 Annual Guidance	2,960	733	9,344	5,250

ABBREVIATIONS USED

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