InPlay Oil

Management's Discussion and Analysis

For the years ended December 31, 2019 and 2018

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEARS ENDED DECEMBER 31, 2019 AND DECEMBER 31, 2018

The following management's discussion and analysis ("**MD&A**") is dated March 17, 2020 and should be read in conjunction with the audited financial statements of InPlay Oil Corp. ("**InPlay**" or the "**Company**") for the years ended December 31, 2019 and December 31, 2018. The financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") and interpretations of the IFRS Interpretations Committee.

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 and years ended December 31, 2019 and December 31, 2018 were as follows:

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Crude oil (bbls/d)	**2,466**	2,937	**2,626**	2,756
NGL (boe/d)	**869**	573	**697**	492
Natural gas (Mcf/d)	**9,978**	9,065	**10,058**	8,431
Total (boe/d)[(1)]	**4,998**	5,021	**5,000**	4,653

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

Production for the year ended December 31, 2019 was 7% higher (light crude oil and liquids; 2% higher) than the same period in 2018, primarily as a result of the added volumes from the drilling program during 2019. These increases were realized despite the October 1, 2018 disposal of assets producing approximately 250 boe/d (72% light oil and liquids).

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. Eight (4.8 net) ERH wells were drilled in Willesden Green and three (3.0 net) horizontal wells were drilled in Pembina.

The Company began its 2020 capital program drilling one (1.0 net) extended reach horizontal ("ERH") wells and three (3.0 net) one-mile horizontal wells to date in the first quarter of 2020.

Crude oil and natural gas sales

(thousands of dollars)		Three months ended December 31				Year ended December 31		
		2019		2018		**2019**		2018
Crude oil [(1)]	$	**14,754**	$	9,694	$	**63,805**	$	64,834
NGLs		**1,367**		1,635		**4,835**		6,874
Natural gas		**2,304**		1,387		**6,385**		4,711
Total crude oil and natural gas sales	$	**18,425**	$	12,716	$	**75,025**	$	76,419

(1) The amounts relating to the quarter and year ended December 31, 2018 are inclusive of $1.1 million in purchases of crude oil volumes made in the fourth quarter of 2018.

Prices

		Three months ended December 31				Year ended December 31		
		2019		2018		**2019**		2018
Crude oil ($/bbl)	$	**65.03**	$	35.88	$	**66.56**	$	64.46
NGLs ($/boe)		**17.10**		31.01		**19.02**		38.27
Natural gas ($/Mcf)		**2.51**		1.66		**1.74**		1.53
Total ($/boe)	$	**40.07**	$	27.53	$	**41.11**	$	45.00

West Texas Intermediate ("WTI") prices decreased in the fourth quarter of 2019 compared to average prices during the fourth quarter of 2018. In the fourth quarter of 2019, WTI oil prices decreased 3% averaging $56.95 US per bbl compared to $58.81 US per bbl in the fourth quarter of 2018. WTI prices also decreased over 2019 compared to 2018, with WTI oil prices decreasing 12% averaging $57.03 US per bbl in 2019 compared to

$64.77 US per bbl in 2018.

Offsetting the decreases to WTI prices for the fourth quarter and year ended December 31, 2019 compared to the same periods in 2018 were recoveries to differential. Differentials between WTI oil prices and prices received in Alberta are volatile due to factors including refining demand and pipeline capacity. InPlay sells its oil at monthly average Edmonton Par prices less quality differentials, transportation and marketing fees. Light, sweet oil differentials between Cushing, Oklahoma and Edmonton, Alberta are affected by pipeline apportionment, refinery turnarounds, rail capacity and market supply/demand conditions.

Monthly index differentials averaged $4.88 US per barrel discount for 2019 compared to $11.12 US per barrel discount for 2018. Monthly index differentials averaged $5.37 US per barrel discount for the fourth quarter of 2019 compared to $26.30 US per barrel discount for the fourth quarter of 2018. A significant widening of differentials started to occur in September of 2018 and increased further into the end of 2018 due to pipeline apportionments and refinery turnarounds. These differentials returned to more historically normal levels during the first quarter of 2019.

In the fourth quarter of 2019, natural gas AECO daily index prices increased 58% averaging $2.34 per Mcf compared to $1.48 per Mcf in the fourth quarter of 2018. Natural gas benchmark prices also increased over 2019 compared to 2018, with AEO daily index prices increasing 18% averaging $1.67 per Mcf in 2019 compared to $1.42 per Mcf in 2018. Certain NGL benchmark prices were at or near all-time lows at points during 2019.

Realized oil prices are adjusted for the Canada/US exchange rate which decreased averaging 0.75 for 2019 compared to 0.77 during 2018. The Canada/US exchange rate remained consistent at 0.76 during the fourth quarter of 2019 and 2018.

Due to the items noted above, fourth quarter 2019 realized prices increased significantly compared to the fourth quarter of 2018. The Company's average net realized price for crude oil was $65.03 per bbl for the quarter ended December 31, 2019, 81% higher than the fourth quarter 2018 price of $35.88 per bbl. The Company's average realized NGL sales price was $17.10 per boe for the fourth quarter of 2019, 45% lower than the fourth quarter of 2018 price of $31.01 per boe as a result of the continued significant reductions in butane and propane prices due to excess supply in the market. The Company's average realized natural gas sales price was $2.51 per Mcf for the three months ended December 31, 2019, 51% higher than the fourth quarter of 2018 price of $1.65 per Mcf.

Realized oil prices for 2019 also increased compared to 2018. The Company's average price for crude oil was $66.56 per bbl for 2019, 3% higher than the 2018 price of $64.46 per bbl. The Company's average realized NGL sales price was $19.02 per boe for 2019, 50% lower than the 2018 price of $38.27 per boe, also as a result of the reduced NGL prices received following the significant reductions in propane and butane pricing during the last three quarters of 2019. The Company's average realized natural gas sales price was $1.74 per Mcf for 2019, 14% higher than 2018 price of $1.53 per Mcf.

Royalties

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

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

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Total royalties ($'000s)	**1,068**	1,125	**5,827**	8,009
Total royalties (% of sales)	**5.8%**	8.9%	**7.8%**	10.5%
Total royalties ($/boe)	$ **2.32**	$ 2.43	$ **3.19**	$ 4.72

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

Derivative contracts

The Company's production is usually sold using "spot" or near-term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company may selectively enter into commodity derivative contracts in order to hedge 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, 2019 the Company did not have any commodity-based derivative contracts outstanding.

Subsequent to December 31, 2019 the Company entered into natural gas derivative contracts as follows:

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

Currency denomination	Volume (GJ/day)	Average swap price	Term
Canadian dollar	4,000	1.61/GJ	April 1, 2020 – October 31, 2020

The statements of (loss) and comprehensive (loss) for the year ended December 31, 2019 reflected the following gains/(losses) related to derivative contracts that were outstanding during 2019 and the comparative periods for 2018.

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Realized gain (loss)	**-**	(305)	**22**	(4,117)
Unrealized gain (loss)	**-**	1,539	**(149)**	1,728
Total (loss) on derivative contracts	**-**	1,234	**(127)**	(2,389)

Operating expenses

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Total operating costs ($'000s)	**7,074**	7,047	**26,206**	27,206
Total operating costs ($/boe)	**15.38**	15.26	**14.36**	16.02

Operating costs include expenses incurred to operate wells, gather and treat production volumes as well as costs to perform well and facility repairs and maintenance. For the three months ended December 31, 2019, operating expenses remained relatively unchanged at $15.38 per boe compared to $15.26 per boe for the same period in 2018. For the year ended December 31, 2019, operating expenses decreased 10% to $14.36 per boe compared to $16.02 per boe for the same period in 2018. Improvements in operating costs for 2019 compared to 2018 on a per boe basis resulted from additional focus on cost reductions and improved operating efficiencies from new technology implemented on new wells drilled and brought on production during 2019.

Transportation expenses

	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Total transportation costs ($'000s)	**307**	461	**1,474**	1,411
Total transportation costs ($/boe)	**0.67**	1.00	**0.81**	0.83

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, 2019, transportation expenses were $0.67 per boe and were lower in comparison to $1.00 per boe for the quarter ended December 31, 2018. For the year ended December 31, 2019, transportation expenses were $0.81 per boe and were also lower in comparison to $0.83 per boe for the year ended December, 2018.

Operating Income and Netback

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Revenue[(1)]	$ **18,425**	$ 12,716	$ **75,025**	$ 76,419
Royalties	**(1,068)**	(1,125)	**(5,827)**	(8,009)
Operating expenses	**(7,074)**	(7,047)	**(26,206)**	(27,206)
Transportation expenses	**(307)**	(461)	**(1,474)**	(1,411)
Operating income [(2)]	$ **9,976**	$ 4,083	$ **41,518**	$ 39,793
Sales volume (Mboe)	**459.8**	461.9	**1,824.8**	1,698.3
Per boe				
Revenue[(1)]	$ **40.07**	$ 27.53	$ **41.11**	$ 45.00
Royalties	**(2.32)**	(2.43)	**(3.19)**	(4.72)
Operating expenses	**(15.38)**	(15.26)	**(14.36)**	(16.02)
Transportation expenses	**(0.67)**	(1.00)	**(0.81)**	(0.83)
Operating netback per boe [(2)]	$ **21.70**	$ 8.84	$ **22.75**	$ 23.43
Operating income profit margin	**54%**	32%	**55%**	52%

(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 fourth quarter of 2019 increased 145% compared to the fourth quarter of 2018 reflecting more normalized light sweet oil differentials being realized starting in January 2019 and continuing throughout the year . Despite the 9% decrease in realized prices in 2019 compared to 2018, the Company's operating netback decreased by only 3% and operating income profit margins improved by 6%, primarily due to operational efficiencies resulting in lower operating costs and lower royalty rates during 2019.

General and administrative expenses

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

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Gross G&A expenditures	$ **1,882**	$ 1,876	$ **8,124**	$ 7,839
Capitalized and recoveries	**(392)**	(391)	**(1,697)**	(1,592)
General and administrative expenses	$ **1,490**	$ 1,485	$ **6,427**	$ 6,247
G&A expenses ($/boe)	$ **3.24**	$ 3.21	$ **3.52**	$ 3.68
% Capitalized and recoveries	**21%**	21%	**21%**	20%

For the year ended December 31, 2019, G&A expenses were $6.4 million ($3.52 per boe) compared to $6.2 million ($3.68 per boe) for 2018. G&A expenses were $1.5 million ($3.24 per boe) for the fourth quarter of 2019 compared to $1.5 million ($3.21 per boe) in the fourth quarter of 2018.

Share-based compensation expenses

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

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Share-based compensation	**92**	428	**861**	1,572
Capitalized portion	**(20)**	27	**(190)**	(335)
Share-based compensation expense	**72**	455	**671**	1,237

During 2019, 3,389,200 options were granted and 252,000 options were forfeited. In addition, 4,259,400 stock options were surrendered and cancelled, resulting in the recognition of $0.1 million in share based compensation expense. Subsequent to December 31, 2019, the Company granted 148,500 stock options at an average exercise price of $0.50 per share.

At December 31, 2019, the maximum number of stock options available for grant was 6,825,662.

Depletion and depreciation

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Depletion and depreciation ($'000s)	**7,077**	7,229	**29,053**	27,202
Depletion and depreciation ($/boe)	**15.39**	15.65	**15.92**	16.02

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 $29.1 million ($15.92 per boe) for the year ended December 31, 2019 compared to $27.2 million ($16.02 per boe) in 2018. Depletion and depreciation was $7.1 million ($15.39 per boe) in the fourth quarter of 2019 compared to $7.2 million ($15.65 per boe) in the fourth quarter of 2018.

Impairment loss

Indicators of impairment relating to Property, plant and equipment were considered to exist as at December 31, 2019 as the Company's net assets were greater than its market capitalization. Impairment tests were performed for each the Company's CGUs which resulted in an impairment loss of $0.7 million being recorded in the Company's statement of (loss) and comprehensive (loss) relating to the Company's Huxley 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 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.

During the year ended December 31, 2018, the Company completed a strategic disposition of certain non-core oil and gas properties in the west Pembina area of Alberta for cash consideration of $16.7 million, before closing adjustments. At September 30, 2018, the Company classified these assets as held for sale. Immediately prior to classifying the assets as held for sale, the Company conducted a review of the assets' recoverable amounts based on expected consideration to be received and transferred these assets at their carrying amount, with an impairment loss of $3.9 million being recognized. The recoverable amount was determined based on the assets' fair value less costs of disposal which was based on the purchase price before closing adjustments.

At December 31, 2019, the Company evaluated its remaining Exploration and evaluation assets for indicators of any potential impairment. As a result of this assessment, no indicators were identified and no additional

Finance expenses

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Interest expense (Credit Facility and other)	**629**	538	**2,548**	2,327
Interest expense (Lease liabilities)	**10**	-	**24**	-
Accretion on decommissioning obligations	**547**	362	**1,449**	1,547
Finance expense	**1,186**	900	**4,021**	3,874

Finance expenses were $1.2 million for the fourth quarter of 2019, compared to $0.9 million in the fourth quarter of 2018. Finance expenses were $4.0 million for the year ended December 31, 2019, compared to $3.9 million in 2018.

Income taxes

The Company has recognized a deferred tax asset in the amount of $30.3 million at December 31, 2019. The Company recognized deferred tax expense of $26.8 million during the year ended December 31, 2019.

The deferred tax asset is supported by the expected future utilization of tax attributes based upon future cashflows derived from the Company's updated forecasts and independent year end reserve report using the total proven and probable cashflows and expenditures and factoring in expected corporate general and administrative and interest expenses. As a result of the a decrease in these future cashflows, the deferred tax asset was reduced by $18.4 million as at December 31, 2019, with a corresponding charge to deferred income tax expense.

During the quarter ended June 30, 2019, the Alberta corporate tax rate decreased from 12% to 8%. The tax rate decrease will be phased in as follows: 11% effective July 1, 2019, 10% effective January 1, 2020, 9% effective

January 1, 2021, and 8% effective January 1, 2022. This rate change results in decreased future value attributable to the Company's unused tax losses and temporary differences. As a result, the Company has recognized a reduction to its deferred tax asset and a deferred income tax expense of $8.5 million 2019.

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at December 31, 2019.

Non-capital loss carryforward balances	$	87,717
Share issue costs		1,642
Canadian Exploration Expenses (CEE)		64,773
Canadian Development Expenses (CDE)		68,909
Canadian Oil and Gas Property Expenses (COGPE)		118,156
Undepreciated Capital Cost (UCC)		50,103
Total	$	391,300

FUNDS FLOW AND ADJUSTED FUNDS FLOW

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

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

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Funds flow	**7,592**	1,441	**30,984**	25,800
Decommissioning expenditures	**254**	280	**1,557**	1,240
Adjusted funds flow[1]	**7,846**	1,721	**32,541**	27,040

(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 and year ended December 31, 2019, was $7.6 million and $31.0 million, respectively, compared to $1.4 million and $25.8 million for the same periods in 2018. Adjusted funds flow for the three months and year ended December 31, 2019, was $7.8 million and $32.5 million, respectively, compared to $1.7 million and $27.0 million for the same periods in 2018. These changes are reflective of the changes to benchmark prices realized during the respective periods.

CAPITAL EXPENDITURES

Capital expenditures for the three months and year ended December 31, 2019 were $4.6 million and $32.2 million, respectively. The breakdown of capital expenditures is shown below:

The breakdown of expenditures is shown below:

(thousands of dollars)	Three months ended December 31 **2019**	2018	Year ended December 31 **2019**	2018
Land and lease	$ **30**	$ 74	$ **99**	$ 1,633
Drilling & completions	**3,213**	4,915	**23,346**	39,207
Facilities and equipping costs	**991**	1,635	**7,149**	8,022
Total exploration and development capital	**4,234**	6,624	**30,594**	48,862
Office and Capitalized G&A	**340**	330	**1,512**	1,344
Total	**4,574**	6,954	**32,106**	50,206
Net Property Acquisitions (Dispositions)(1)	**14**	(17,305)	**93**	(21,470)
Total capital expenditures	$ **4,588**	$ (10,351)	$ **32,199**	$ 28,736

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

InPlay's 2019 capital program 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.

Drilling statistics are shown below:

	Three months ended December 31				Year ended December 31			
	2019		2018		**2019**		2018	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil (1)	**6.0**	**3.5**	3.0	2.2	**13.0**	**8.2**	16.0	11.2
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**6.0**	**3.5**	3.0	2.2	**13.0**	**8.2**	16.0	11.2
Success rate	**100%**	**100%**	100%	100%	**100%**	**100%**	100%	100%

(1) The Company also drilled and abandoned a vertical stratigraphic test well in the Duvernay area during the fourth quarter of 2018 that is not included above.

SHARE INFORMATION

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

As of March 17, 2020, there were 68,256,616 common shares outstanding and 5,327,800 stock options that, subject to vesting, are convertible into, or exercisable or exchangeable for, an equivalent number of common shares of the Company.

RELATED PARTY TRANSACTIONS

InPlay had no related party transactions that were entered into under the normal course of business for the three months and years ended December 31, 2019 and December 31, 2018.

LIQUIDITY AND CAPITAL RESOURCES

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

At December 31, 2019, the Company has a syndicated $75 million senior secured revolving credit facility (the "**Credit Facility**"). The Credit Facility consists of a $65 million revolving line of credit and a $10 million operating line of credit. The Credit Facility has a term date of May 31, 2020, and, if not extended, additional advances would not be permitted and any outstanding advances would become repayable one year later on May 31, 2021. The Credit Facility is secured by a floating charge debenture and a general security agreement on the assets of the Company. At December 31, 2019 the Company had drawn $53.6 million on the Credit Facility. The available lending limit of the Credit Facility is scheduled for annual review on or before May 31, 2020 and is based on the Lenders' interpretation of the Company's reserves and future commodity prices. In addition, a provision has been put in place until the next annual review on May 31, 2020 in which the borrowing base may be redetermined if requested by any lender in the event the outstanding principal under the Credit Facility exceeds $60 million. There can be no assurance that the amount or terms of the available Credit Facility will not be adjusted at the next review. In the event that the lenders reduce the borrowing base below the amount drawn at the time of the redetermination, the Company would have 60 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. There are standard reporting covenants under the Credit Facility however there are no financial covenants. The Company was in compliance with these standard reporting covenants as at December 31, 2019.

In addition, at December 31, 2019 the Company had a working capital deficit of $1.5 million. The Company expects to have a higher level of current liabilities due to the increased amounts of accounts payable and accrued liabilities related to the active drilling program underway at year end.

The Company's Net debt/adjusted funds flow(1) ratio for the year ended December 31, 2019 improved to 1.7x compared to 2.0x for the year ended December 31, 2018 largely due to the impact of decreased realized prices on adjusted funds flow for the three months ended December 31, 2018.

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

OFF-BALANCE SHEET ARRANGEMENTS

The Company had no guarantees or off-balance sheet arrangements other than as described below under "Contractual Obligations."

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. At December 31, 2019, these obligations include:

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

As at December 31, 2019 the Company had the following minimum contractual obligations:

Contractual obligations (in thousands of dollars)	Payments due by year 2020	2021	2022	2023	2024	Thereafter
Accounts payable	13,933	-	-	-	-	-
Bank debt - principal(1)	-	53,635	-	-	-	-
Bank debt - interest(2)	2,448	1,020	-	-	-	-
Non-cancellable office leases	377	377	31	-	-	-
Other leases	154	87	19	-	-	-
Firm service(3)	225	70	44	42	42	52
Total	17,137	55,189	94	42	42	52

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

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

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 3 to the Company's audited financial statements for the years ended December 31, 2019 and December 31, 2018. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results than reported. The Company's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results that differ materially from current estimates.

Oil and natural gas reserves

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

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

Recoverable amounts of CGUs

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

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

Decommissioning obligations

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

Income taxes

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

CHANGES IN ACCOUNTING POLICIES

There were no new or amended accounting standards or interpretations adopted in the year ended December 31, 2019, other than the following:

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

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

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

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

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

CONTROLS AND PROCEDURES

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. 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 for the foregoing purposes.

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, for the foregoing purpose. 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, 2019 and ended on December 31, 2019 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

BUSINESS RISKS

Oil and natural gas exploration and production is capital intensive and involves a number of business risks including, without limitation, the uncertainty of finding new reserves, the instability of commodity prices, weather, and various operational risks. Commodity prices are influenced by local and worldwide supply and demand, OPEC actions, ongoing global economic concerns, the US dollar exchange rate, transportation costs, political stability, and seasonal and weather-related changes to demand. The concern over increasing US natural gas production, driven primarily by the US shale gas plays, continues to depress the natural gas futures market. Oil prices declined sharply in the latter part of 2015 and continue to remain volatile as oil is a geopolitical commodity, affected by concerns about global economic markets, continued instability in oil producing countries and increases in production from US tight oil plays. Differentials between WTI oil prices and prices received in Alberta are volatile. The industry is subject to extensive governmental regulation with respect to the environment.

Over the past number of years, several new environmental regulations at both the Federal and Provincial level were announced, though the details of how some of the regulations will be implemented have yet to be released. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain and maintain drilling licenses and other regulatory approvals, ability to obtain equipment, expiration of licenses and leases, competition from other producers, third-party transportation and processing disruption issues, sufficiency of insurance, ability to manage growth, reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These additional risks are described in more detail in the Company's most recent AIF filed with 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.

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

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, the novel coronavirus (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 began the 2020 capital program drilling one (1.0 net) ERH horizontal Willesden Green well and three (3.0 net) horizontal Pembina wells in the first quarter of 2020. The Company also recompleted and commissioned a water disposal well in Pembina which is expected to provide long term savings in the area. All wells drilled in the first quarter have been completed and placed on production albeit at lower ramp up rates than would normally occur, as a result of the current low oil price.

In January of 2020, the Company's Board of Directors had approved a 2020 capital program of $35 million which was less than projected AFF on WTI futures pricing of $57 USD/bbl. With the significant drop and volatility in world crude oil prices as a result of the COVID – 19 outbreak and the corresponding oil price war, consistent with past practices the Company will manage its spending and adjust the capital program accordingly throughout 2020 and no longer has plans for capital spending of $35 million. InPlay has completed its first quarter capital program and only minimal capital spending is expected over the second quarter during spring break-up. As such, no major capital spending decisions are being made at this time. Capital planning decisions for the second half of 2020 and any updated forecasts will be made in due course in consideration of forecasted AFF reflecting the prevailing commodity prices at that time.

The Company's low decline rate, strong operating netbacks, top-tier capital efficiencies, lack of drilling commitments and primarily operated capital program provide flexibility in this volatile market. Efforts have been initiated to optimize operations in order to minimize costs and preserve value for the Company. All operations will be thoroughly vetted to optimize corporate cash flows which may include shutting in any wells that that will not generate positive cash flow under current prices (net of fixed cost considerations). Further operating and corporate cost efficiencies will also be pursued in consideration of the current pricing environment.

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 2019**	Q3 2019	Q2 2019	Q1 2019
Oil and natural gas sales	**18,425**	17,395	19,995	19,210
Oil and natural gas sales, net of royalties	**17,357**	15,737	18,386	17,718
Profit (loss)	**(18,892)**	(1,355)	(7,629)	1,035
Profit (loss) per share, basic and diluted	**(0.28)**	(0.02)	(0.11)	0.02
Exploration and development capital expenditures	**4,574**	8,082	4,688	14,763
Property acquisitions/(dispositions)	**14**	-	(9)	87
Funds flow	**7,592**	6,397	8,461	8,534
Adjusted funds flow(1)	**7,846**	6,886	8,755	9,054
Adjusted funds flow per share, basic and diluted(1)	**0.11**	0.10	0.13	0.13
Adjusted funds flow per boe(1)	**17.06**	14.73	18.58	21.24
Net debt	**55,170**	58,053	56,304	60,033

	Q4 2018	Q3 2018	Q2 2018	Q1 2018
Oil and natural gas sales	12,716	22,801	20,993	19,909
Oil and natural gas sales, net of royalties	11,591	20,153	18,748	17,919
Profit (loss)	(7,887)	(1,775)	(326)	1,390
Profit (loss) per share, basic and diluted	(0.12)	(0.03)	0.00	0.02
Exploration and development capital expenditures	6,954	17,376	12,329	13,546
Property acquisitions/(dispositions)	(17,305)	(26)	184	(4,321)
Funds flow	1,441	9,962	7,305	7,095
Adjusted funds flow(1)	1,721	10,006	7,376	7,939
Adjusted. funds flow per share, basic and diluted(1)	0.03	0.15	0.11	0.12
Adjusted funds flow per boe(1)	3.73	22.79	18.44	19.98
Net debt	53,670	66,005	58,616	53,407

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

The Company's 2018 drilling program consisted of $50.2 million of capital mainly focused on the Willesden Green bioturbated Cardium where the Company drilled 12 (8.6 net) extended reach horizontal ("ERH") wells and 4 (2.6 net) one-mile horizontal wells. Completion of 2 (2.0 net) of these ERH wells was performed in January 2019. In aggregate, InPlay drilled an equivalent of 23.0 gross horizontal miles (16.5 net horizontal miles). In addition, we completed our first Duvernay horizontal well during the second quarter of 2018. One vertical stratigraphic test well was drilled in the Duvernay area in the fourth quarter extending the land tenure on this block for an additional five years. The Company also spent $1.4 million acquiring an additional 12 sections of undeveloped Crown land in the Duvernay area. The Company purchased minor producing assets which had significant associated undeveloped lands and beneficial interests in various facilities in the Willesden Green area of Alberta, Canada for consideration of $5.5 million in the first quarter of 2018. The Company also completed the sale of a non-core processing facility and associated equipment and infrastructure for proceeds of $10.0 million during the first quarter of 2018. On October 1, 2018 the Company completed a strategic disposition of certain non-core oil and gas properties in the west Pembina area of Alberta for cash consideration of $16.6 million disposing of approximately 250 boe/d.

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

SELECTED ANNUAL INFORMATION

Years ended December 31

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

(1) The oil and natural gas sales exclude realized and unrealized gains (losses) on risk management derivative contracts: 2019 excludes $0.02 million realized gain and ($0.1) million unrealized loss; 2018 excludes ($4.1) million realized loss and $1.7 million unrealized gain; 2017 excludes $1.1 million realized gain and ($0.03) million unrealized loss.

ADDITIONAL INFORMATION

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

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

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

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

NON-GAAP MEASURES

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

Adjusted Funds Flow

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

(thousands of dollars)	Three months ended December 31		Year ended December	
	2019	2018	**2019**	2018
Adjusted funds flow	**7,846**	1,721	**32,541**	27,040
Weighted avg. number of common shares (basic and diluted ('000s)	**68,257**	67,987	**68,257**	67,912
Adjusted funds flow per share, basic and diluted	**0.11**	0.03	**0.48**	0.40

Adjusted Funds Flow per boe

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

(thousands of dollars)	Three months ended December 31		Year ended December 31	
	2019	2018	**2019**	2018
Adjusted funds flow	**7,846**	1,721	**32,541**	27,040
Sales volume (Mboe)	**459.8**	461.9	**1,824.8**	1,698.3
Adjusted funds flow per boe	**17.06**	3.73	**17.83**	15.92

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/Adjusted funds flow

Management considers net debt/ adjusted funds flow to be an important measure of InPlay's liquidity and ability to generate funds necessary to repay upcoming obligations. Net debt/adjusted funds flow is calculated by the Company as net debt divided by adjusted funds flow for the current year m. A reconciliation of net debt to net debt/adjusted funds flow is as follows:

(thousands of dollars)	Year ended December 31	
	2019	2018
Net debt	**55,170**	53,670
Adjusted funds flow	**32,541**	27,040
Net debt/Adjusted funds flow	**1.7x**	2.0x

FORWARD-LOOKING STATEMENTS

This MD&A contains certain forward-looking statements and forward-looking information (collectively referred to herein as "**FLI**" or "**forward-looking statements**") within the meaning of applicable Canadian securities laws. All statements other than statements of present or historical fact are forward-looking statements. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "believe", "plan", "intend", "objective", "continuous", "ongoing", "estimate", "expect", "may", "will", "project", "should", or similar words suggesting future outcomes. In particular, this MD&A contains forward-looking statements relating, but not limited, to:

- drilling and development plans, and the timing thereof;
- InPlay's business strategy, goals and management focus;
- sources of funds for the Company's operations, capital expenditures and decommissioning obligations;
- future liquidity and the Company's access to sufficient debt and equity capital;
- the resource potential of InPlay's asset base and future prospects for development and growth;
- expectations regarding the business environment, industry conditions and future commodity prices, including the potential impact of COVID-19;
- expectations regarding InPlay's 2020 forecasted capital expenditures, production estimates including current 2020 average and exit forecasts, future operating costs, cash flows and forecasted 2020 adjusted funds flow;
- 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; 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 following table summarizes the Company's actual results for 2019 compared to the most recently forecasted information:

	Prior Forecast	2019 Actuals	% Variance
Production (boe/d)	5,000 – 5,200	5,000	-
Oil and liquids weighting (%)	67%	66%	(1)
E&D Capital Expenditures ($ million)	$32.0	$32.1	-
Net wells drilled	8.2	8.2	-
Operating income profit margin (%)	55% - 56%	55%	-
Funds flow ($ million)	$30 - $33	$31.0	-
Adjusted funds flow ($ million)	$31 - $34	$32.5	-

In January 2020, the Company disclosed forecasted information for 2020 including the forecast capital program of $35 million, net wells to be drilled, annual average production, AFF and operating income profit margin. The Company has elected to withdraw this FLI as this forecast is no longer realistic given the significant declines in the spot price for oil for various reasons linked to the COVID-19 pandemic and other conditions impacting worldwide oil prices.

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