Management's Discussion and Analysis

For the years ended December 31, 2018 and 2017

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEARS ENDED DECEMBER 31, 2018 AND DECEMBER 31, 2017

The following management's discussion and analysis ("**MD&A**") is dated March 19, 2019 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, 2018 and December 31, 2017. 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 potential 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.**". InPlay has the same directors and management as Prior InPlay. Effective November 10, 2016 the 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. The number of commons shares for all periods shown in this MD&A were adjusted retrospectively to reflect the InPlay Exchange Ratio.

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

	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Crude oil (bbls/d)	**2,937**	2,503	**2,756**	2,310
NGL (boe/d)	**573**	371	**492**	352
Natural gas (Mcf/d)	**9,065**	7,866	**8,431**	7,857
Total (boe/d)[1]	**5,021**	4,185	**4,653**	3,972

(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 fourth quarter and year ended December 31, 2018 was considerably higher than the respective comparable periods for 2017 due to the additional volumes from the drilling program that started in the fourth quarter of 2017 and continued throughout 2018.

Average production volumes in the fourth quarter of 2018 compared to the third quarter of 2018 were as follows:

	Three months ended	
	Dec 31, 2018	Sept 30, 2018
Crude oil (bbls/d)	**2,937**	2,775
NGL (boe/d)	**573**	541
Natural gas (Mcf/d)	**9,065**	8,738
Total (boe/d)	**5,021**	4,773

Production for the quarter ended December 31, 2018 increased compared to the quarter ended September 30, 2017 due to 3.0 gross (2.2 net) wells being brought on production late in October 2018.

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 2018 capital program 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 two (2.0 net) of these ERH wells that were drilled in the fourth quarter of 2018 occurred 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 also drilled in the Duvernay area in the fourth quarter extending our land tenure for an additional four to five years. The Company also spent $1.4 million acquiring an additional 12 sections of undeveloped Crown land in the Duvernay area in 2018.

The Company's drilling program has continued in the first quarter of 2019, drilling an additional 5 (2.7 net) ERH wells to date in the first quarter of 2019.

Crude oil and natural gas sales

		Three months ended December 31			Year ended December 31	
(thousands of dollars)		**2018**	2017		**2018**	2017
Crude oil (1)	$	**9,694**	$ 15,157	$	**64,834**	$ 50,821
NGLs		**1,635**	1,450		**6,874**	4,595
Natural gas		**1,387**	1,410		**4,711**	6,823
Total crude oil and natural gas sales	$	**12,716**	$ 18,017	$	**76,419**	$ 62,239

(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	
		2018	2017		**2018**	2017
Crude oil ($/bbl)	$	**35.88**	$ 65.81	$	**64.46**	$ 57.02
NGLs ($/boe)		**31.01**	42.52		**38.27**	35.74
Natural gas ($/Mcf)		**1.66**	1.95		**1.53**	2.38
Total ($/boe)	$	**27.53**	$ 46.79	$	**45.00**	$ 42.93

Crude oil benchmark prices decreased in the fourth quarter compared to average prices during the third quarter 2018, affecting realized oil prices. In the fourth quarter of 2018, WTI oil prices decreased 15% averaging $58.81 US per bbl compared to $69.50 US per bbl in the third quarter of 2018.

Crude oil benchmark prices improved in the fourth quarter compared to average prices during the fourth quarter of 2017. In the fourth quarter of 2018, WTI oil prices increased 6% averaging $58.81 US per bbl compared to $55.40 US per bbl in the fourth quarter of 2017. Crude oil benchmark prices also improved over 2018 compared to 2017, with WTI oil prices increasing 27% averaging $64.77 US per bbl in 2018 compared to $50.95 US per bbl in 2017.

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.

Starting in September, pipeline apportionments and refinery turnarounds caused a widening in these differentials. The monthly index differential widened substantially and delivery apportionments were instituted by shippers resulting in reduced pricing on all apportioned volumes. Monthly index differentials averaged $26.30 US per barrel discount for the fourth quarter of 2018 compared to $1.14 US per barrel for the fourth quarter of 2017. This average differential also increased for 2018, averaging $11.12 US per barrel discount compared to $2.46 US per barrel in 2017. The Company realized higher differentials above the average monthly index in the amount of $6.20 bbl CAD/bbl over the quarter ($2.06 CAD/bbl over 2018) due to discounted apportionment sales resulting from extended refinery turnarounds in the Midwest USA, increased oil supplies and transportation infrastructure restrictions.

Realized oil prices are adjusted for the Canada/US exchange rate which decreased averaging 0.76 for the fourth quarter of 2018 compared to 0.79 for the fourth quarter of 2017. The Canada/US exchange rate remained consistent at 0.77 during 2018 and 2017.

Due to the factors above, fourth quarter 2018 realized prices decreased compared to the fourth quarter of 2017. The Company's average price for crude oil was $35.88 per bbl for the quarter ended December 31, 2018, 45% lower than the fourth quarter 2017 price of $65.81 per bbl. The Company's average realized natural gas sales price was $1.65 per Mcf for the three months ended December 31, 2018, 15% lower than the fourth quarter of 2017 price of $1.95 per Mcf. The impact of natural gas prices was limited as natural gas revenue only comprised

4% of total Company revenues for the quarter.

Realized oil prices for year ended December 31, 2018 increased compared to 2017. The Company's average price for crude oil was $64.46 per bbl for 2018, 7% higher than the 2017 price of $60.27 per bbl. Realized natural gas prices decreased over the two respective periods. The Company's average realized natural gas sales price was $1.53 per Mcf for 2018, 36% lower than the 2017 price of $2.38 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	
	2018	2017	**2018**	2017
Total royalties ($'000s)	**1,125**	1,762	**8,009**	6,267
Total royalties (% of sales)	**8.9%**	9.8%	**10.5%**	10.1%
Total royalties ($/boe)	$ **2.43**	$ 4.58	$ **4.72**	$ 4.32

Royalties rates as a percentage of sales and per boe have decreased during the fourth quarter of 2018 due to the significant decrease in realized crude oil prices over the three month period ended December 31, 2018.

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, 2018 the following commodity-based derivative contracts were outstanding and recorded at estimated fair value:

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

Currency denomination	Volume (bpd)	Bought put price	Sold call price	Sold put price	Term	Fair value ($'000 CAD)
US dollar	250	42.00/bbl	50.00/bbl	65.10/bbl	April 1, 2018 – March 31, 2019	$149

(1) 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.

The statements of (loss) and comprehensive (loss) for the year ended December 31, 2018 reflected the following gains related to derivative contracts that were outstanding during 2018 and the comparative periods for 2017.

(thousands of dollars)	Three months ended December 31 2018	2017	Year ended December 31 2018	2017
Realized gain (loss)	$ **(305)**	$ 163	$ **(4,117)**	$ 1,114
Unrealized (loss)	**1,539**	(1,819)	**1,728**	(30)
Total gain (loss) on derivative contracts	$ **1,234**	$ (1,656)	$ **(2,389)**	$ 1,084

The following commodity-based derivative contracts were held by the Company during the year ended December 31, 2018:

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

Currency denomination	Volume (GJ/day)	Average swap price	Term
Canadian dollar	1,000	3.055 /GJ	Jan 1, 2017 – March 31, 2018
Canadian dollar	1,000	2.95 /GJ	May 1, 2017 – March 31, 2018

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

Currency denomination	Volume (bpd)	Average swap price	Term
US dollar	200	60.00/bbl	Jan 1, 2018 – March 31, 2018
US dollar	500	57.00/bbl	Jan 1, 2018 – June 30, 2018

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

Currency denomination	Volume (bpd)	Sold call price	Sold put price	Term
US dollar	200	47.00/bbl	52.00/bbl	Sept 1, 2017 – March 31, 2018
US dollar	200	46.00/bbl	53.00/bbl	Sept 1, 2017 – June 30, 2018
US dollar	200	46.00/bbl	53.40/bbl	Oct 1, 2017 – June 30, 2018
US dollar	300	48.00/bbl	57.00/bbl	Nov 1, 2017 – Dec 31, 2018

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

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

Currency denomination	Volume (bpd)	Bought put price	Sold call price	Sold put price	Term
US dollar	300	42.00/bbl	50.00/bbl	64.35/bbl	Jan 1, 2018 – Dec 31, 2018
US dollar	250	42.00/bbl	50.00/bbl	65.10/bbl	April 1, 2018 – March 31, 2019

(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.

Operating expenses

	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Total operating costs ($'000s)	$ **7,047**	$ 5,929	$ **27,206**	$ 23,346
Total operating costs ($/boe)	**15.26**	15.40	**16.02**	16.10

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, 2018, operating expenses decreased to $15.26 per boe compared to $15.40 per boe for the same period in 2017. For the year ended December 31, 2018, operating expenses also decreased to $16.02 per boe compared to $16.10 per boe for the same period in 2017. Total operating costs are up in the three months and year ended December 31, 2018 compared to same periods in 2017 reflecting increased variable operating costs due to increased production from the 2018 drilling program. Improvements in operating costs on a per boe basis reflect fixed operating costs being incurred over a larger production base.

Transportation expenses

	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Total transportation costs ($'000s)	$ **461**	$ 193	$ **1,411**	$ 894
Total transportation costs ($/boe)	**1.00**	0.50	**0.83**	0.62

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, 2018, transportation expenses were $1.00 per boe and were higher in comparison to $0.50 per boe for the quarter ended December 31, 2017. For the year ended December 31, 2018, transportation expenses were $0.83 per boe and were also higher in comparison to $0.62 per boe for the year ended December, 2017.

Transportation expenses for the year and quarter ended December 31, 2018 on a per boe basis were higher than 2017 due to the Company incurring more transportation costs in order to assist in crude movements during the apportionment issues faced during the quarter.

Operating Income and Netback

	Three months ended December 31		Year ended December 31	
(thousands of dollars)	**2018**	2017	**2018**	2017
Revenue[1]	$ **12,716**	$ 18,017	$ **76,419**	$ 62,239
Royalties	**(1,125)**	(1,762)	**(8,009)**	(6,267)
Operating expenses	**(7,047)**	(5,929)	**(27,206)**	(23,346)
Transportation expenses	**(461)**	(193)	**(1,411)**	(894)
Operating income [2]	$ **4,083**	$ 10,133	$ **39,793**	$ 31,732

Sales volume (Mboe)	**461.9**	385.0	**1,698.3**	1,449.3
Per boe				
Revenue[1]	$ **27.53**	$ 46.79	$ **45.00**	$ 42.93
Royalties	**(2.43)**	(4.58)	**(4.72)**	(4.32)
Operating expenses	**(15.26)**	(15.40)	**(16.02)**	(16.10)
Transportation expenses	**(1.00)**	(0.50)	**(0.83)**	(0.62)
Operating netback per boe [2]	$ **8.84**	$ 26.31	$ **23.43**	$ 21.89

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

(2) Operating income and operating netback per BOE 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 were higher for the year ended December 31, 2018 compared to the year ended December 31, 2017 largely due to higher revenue from higher commodity prices and higher production volumes. For the quarter ended December 31, 2018 operating income and operating netback per boe were lower compared to the quarter ended December 31, 2017, primarily due to lower realized oil prices as a result of lower WTI prices and the widening Edmonton light sweet differential experienced during the quarter.

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:

	Three months ended December 31		Year ended December 31	
(thousands of dollars)	**2018**	2017	**2018**	2017
Gross G&A expenditures	$ **1,876**	$ 2,079	$ **7,839**	$ 7,419
Capitalized and recoveries	**(391)**	(346)	**(1,592)**	(1,490)
General and administrative expenses	$ **1,485**	$ 1,733	$ **6,247**	$ 5,929
G&A expenses ($/boe)	$ **3.21**	$ 4.50	$ **3.68**	$ 4.09
% Capitalized and recoveries	**21%**	17%	**20%**	20%

For the year ended December 31, 2018, G&A expenses were $6.2 million ($3.68 per boe) compared to $5.9 million ($4.09 per boe) for 2017. G&A expenses were $1.5 million ($3.21 per boe) for the fourth quarter of 2018 compared to $1.5 million ($3.49 per boe) in the third quarter of 2018 and $1.7 million ($4.50 per boe) for the fourth quarter of 2017.

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).

	Three months ended December 31		Year ended December 31	
(thousands of dollars)	**2018**	2017	**2018**	2017
Share-based compensation	$ **428**	$ 593	$ **1,572**	$ 2,362
Capitalized portion	**27**	(183)	**(335)**	(751)
Share-based compensation expense	$ **455**	$ 410	$ **1,237**	$ 1,611

During the year ended December 31, 2018, 1,519,200 options were granted and 20,100 were forfeited. At December 31, 2018 the maximum number of stock options available for grant was 6,825,662.

Depletion and depreciation

	Three months ended December 31		Year ended December 31	
	2018	2017	**2018**	2017
Depletion and depreciation ($'000s)	$ **7,229**	$ 6,156	$ **27,202**	$ 22,551
Depletion and depreciation ($/boe)	**15.65**	15.99	**16.02**	15.55

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 $27.2 million ($16.02 per boe) for the year ended December 31, 2018 compared to $22.5 million ($15.55 per boe) in 2017. Depletion and depreciation was $7.2 million ($15.65 per boe) in the fourth quarter of 2018 compared to $7.2 million ($16.42 per boe) in the third quarter of 2018 and $6.2 million ($15.99 per boe) in the fourth quarter of 2017.

Impairment loss

Indicators of impairment relating to Property, plant and equipment were considered to exist as at December 31, 2018 as the Company's net assets were greater than its market capitalization. Impairment tests were performed for each the Company's CGUs which did not result in an impairment loss being recorded in the Company's statement of (loss) and comprehensive (loss). The Company used the income approach technique to measure fair value of the CGUs whereby the net present value of the future cash flows were calculated using a discount rate of 12%. The future cash flows were based on level 3 fair value hierarchy inputs: the Company's reserves prepared by its independent reserves evaluator, including key assumptions regarding the discount rate, quantities of reserves and production volumes, future commodity prices as prepared by its independent reserves evaluator, royalty obligations, operating expenses, development costs, and decommissioning costs.

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.

Exploration and evaluation expense

During the year ended December 31, 2018, the Company recorded to Exploration and evaluation expense the drilling of a vertical stratigraphic test well in the amount of $1.2 million. An amount of $1.6 million was also recorded as Exploration and evaluation expense relating to the expiry of undeveloped land leases during the year and anticipated near term undeveloped land lease expiries. The Company also transferred $3.4 million in Exploration and evaluation assets to Property, plant and equipment during the year when these assets demonstrated technical feasibility and commercial viability. At this time, these assets were tested for impairment resulting in an Exploration and evaluation expense of $4.2 million being recorded in the year ended December 31, 2018.

At December 31, 2018, 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 impairment was recorded relating to the Company's Exploration and evaluation assets.

Gain on Disposal

During the year ended December 31, 2018, the Company sold a gas processing facility and associated gathering equipment and infrastructure assets for cash proceeds of $10 million, recognizing a gain on disposition of $2.7 million.

Finance expenses

	Three months ended December 31		Year ended December 31	
(thousands of dollars)	**2018**	2017	**2018**	2017
Interest expense (Credit Facility and other)	$ **538**	$ 517	$ **2,327**	$ 1,602
Accretion on decommissioning obligations	**362**	363	**1,547**	1,480
Finance expenses	$ **900**	$ 880	$ **3,874**	$ 3,082

Finance expenses were $0.9 million for the fourth quarter of 2018, compared to $1.1 million in the third quarter of 2018 and $0.9 million in the fourth quarter of 2017. Finance expenses were $3.9 million for the year ended December 31, 2018, compared to $3.1 million in the comparable period of 2017.

Income taxes

The Company has recognized a deferred tax asset in the amount of $57.1 million at December 31, 2018. The Company recognized a deferred tax recovery of $0.9 million during the year ended December 31, 2018.

The deferred tax asset is supported by the expected future utilization of tax attributes based upon future cashflows derived from the company's 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.

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at December 31, 2018.

Non-capital loss carryforward balances	$ 83,762
Share issue costs	2,003
Canadian Exploration Expenses (CEE)	63,563
Canadian Development Expenses (CDE)	65,301
Canadian Oil and Gas Property Expenses (COGPE)	128,818
Undepreciated Capital Cost (UCC)	45,376
Total	$ 388,823

CAPITAL EXPENDITURES

Capital expenditures were $50.2 million and net property dispositions were $21.5 million for the year ended December 31, 2018. The Company spent $6.9 million on capital expenditures in the fourth quarter of 2018 in addition to dispositions of $17.3 million.

The breakdown of expenditures is shown below:

	Three months ended December 31		Year ended December 31	
(thousands of dollars)	**2018**	2017	**2018**	2017
Land and lease	$ **74**	$ 14,092	$ **1,633**	$ 14,425
Drilling & completions	**4,915**	11,101	**39,207**	29,566
Facilities and equipping costs	**1,635**	1,312	**8,022**	3,758
Total exploration and development capital	**6,624**	26,505	**48,862**	47,749
Office and Capitalized G&A	**330**	487	**1,344**	1,475
Total	**6,954**	26,992	**50,206**	49,224
Net Property Acquisitions (Dispositions)[1]	**(17,305)**	(152)	**(21,470)**	1,067
Total capital expenditures	$ **(10,351)**	$ 26,840	$ **28,736**	$ 50,291

(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.

Refer to the 'Review of Financial Results' section for a description of the Company's 2018 capital program.

Drilling statistics are shown below:

	Three months ended December 31				Year ended December 31			
	2018		2017		**2018**		2017	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil [1]	**3.0**	**2.2**	4.0	4.0	**16.0**	**11.2**	12.0	10.1
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**3.0**	**2.2**	4.0	4.0	**16.0**	**11.2**	12.0	10.1
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 19, 2019, there were 68,256,616 common shares outstanding and 6,364,500 stock options that were convertible into, exercisable or exchangeable for, the same 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 year ended December 31, 2018.

A member of InPlay's board of directors and executive management participated in the flow-through common share issuance during 2017 as described in note 12 to the financial statements. 55,000 flow-through common shares were acquired for proceeds of $99,000. This share offering was done under the same terms and conditions as the other participants as described in note 12 to the financial statements.

LIQUIDITY AND CAPITAL RESOURCES

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

During the year ended December 31, 2018, the Company increased its syndicated senior secured revolving credit facility from $60 million to $75 million (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, 2019, and, if not extended, additional advances would not be permitted and any outstanding advances would become repayable one year later on May 31, 2020. The Credit Facility is secured by a floating charge debenture and a general security agreement on the assets of the Company. At December 31, 2018 the Company had drawn $45.4 million on the Credit Facility. The available lending limit of the Credit Facility is scheduled for annual review on or before May 31, 2019 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 available Credit Facility will not be adjusted at the next review. In the event that the lenders reduced 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, 2018.

In addition, at December 31, 2018 the Company had a working capital (deficit) of ($8.9) million. The Company expects to have a higher level of working capital (deficit) due to the decreased accrued receivables in December 2018 caused by a significant decrease in realized prices and the increased amounts of accounts payable and accrued liabilities related to the active drilling program underway at year end.

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, 2018, these obligations include:

- **Loan agreement** – The reserves-based, extendable, committed-term Credit Facility has a term date of May 31, 2019. If not extended, any outstanding advances would become repayable on May 31, 2020. 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, 2018 were not recognized as a liability at December 31, 2018.

As at December 31, 2018 the Company had the following minimum contractual obligations:

Contractual obligations (in thousands of dollars)	Payments due by year 2019	2020	2021	2022	2023	Thereafter
Accounts payable	15,696	-	-	-	-	-
Bank debt - principal(1)	-	45,400	-	-	-	-
Bank debt - principal(2)	2,074	864	-	-	-	-
Non-cancellable office leases(3)	206	-	-	-	-	-
Firm service(4)	303	188	59	46	44	100
Total	18,279	46,452	59	46	44	100

(1) Assumes the Credit Facility is not renewed as of May 31, 2019, and the entire outstanding balance becomes payable on May 31, 2020.

(2) Assumes interest is incurred on bank debt outstanding at December 31, 2018 at the Company's effective interest rate during the quarter and the principal balance is repaid on May 31, 2020.

(3) Both parties are entitled to terminate the lease agreement at any point after January 31, 2019 provided six months notice is provided to the other party. This commitment table above assumes that this termination will occur on February 1, 2019.

(4) 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 defendant in various legal actions and other disputes arising 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 financial statements. 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, 2018, other than the following:

IFRS 9 "Financial Instruments". The Company has retrospectively adopted, as of January 1, 2018, all of the requirements of IFRS 9 "Financial Instruments", as amended in July 2014 ("IFRS 9"). IFRS 9 replaces the provisions of IAS 39 "Financial Instruments: Recognition and Measurement" ("IFRS 39") that relate to the recognition, classification and measurement of financial assets and financial liabilities, derecognition of financial instruments, impairment of financial assets and hedge accounting. IFRS 9 uses a single approach to determine whether a financial asset is classified and measured at amortized cost, fair value through other comprehensive income or fair value through profit or loss. The new standard has also introduced a single expected credit loss impairment model to determine impairment of financial assets, which is based on changes in credit quality since initial recognition. The adoption of this standard did not result in any adjustments to the amounts recognized in the Company's financial statements for the year ended December 31, 2017. For additional information on the effect of adoption of IFRS 15, refer to note 3 in the Company's financial statements year ended December 31, 2018.

IFRS 15 "Revenue from Contracts with Customers". The Company has adopted IFRS 15 as of January 1, 2018 using modified retrospective application, which resulted in changes in the accounting policies of the

Company. IFRS 15 replaces IAS 11, "Construction Contracts", IAS 18, "Revenue" and several revenue-related interpretations. IFRS 15 provides a single, principles-based five-step model to be applied to all contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive when control is transferred to the purchaser. The adoption of this standard did not result in any adjustments to the amounts recognized in the Company's financial statements for the year ended December 31, 2017. For additional information on the effect of adoption of IFRS 15, refer to note 3 in the Company's financial statements for the year ended December 31, 2018.

NEW AND PENDING ACCOUNTING STANDARDS

Standards that are issued and that the Company reasonably expects to be applicable at a future date are listed below.

IFRS 16 "Leases". On January 13, 2016 the IASB issued IFRS 16 Leases. For lessees applying IFRS 16, a single recognition and measurement model for leases would apply, with required recognition of assets and liabilities for most leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. The standard will come into effect for annual periods beginning on or after January 1, 2019 with earlier adoption permitted. The Company intends to adopt IFRS 16 in its financial statements for the annual periods beginning on January 1, 2019. The expected impact on the opening statement of financial position at January 1, 2019, is an immaterial increase to Property, plant and equipment and a corresponding immaterial increase to total liabilities. Interest expense will be recognized on the lease obligation and lease payments will be applied against the lease obligation. Depreciation will be incurred on the portion of the lease recorded to Property, plant and equipment.

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, 2018 and ended on December 31, 2018 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 throughout 2016, 2017, 2018 and into 2019, 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 year, 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 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.

OUTLOOK

Following the improvements in crude oil price differentials seen at the beginning of 2019, InPlay initiated its 2019 capital program beginning with the completions of the two ERH horizontal Willesden Green wells that were drilled in 2018. We commenced drilling 2.7 net ERH wells in the first quarter of our estimated 9 net horizontal well drilling program budgeted for 2019. All wells drilled in the first quarter have been completed with initial results in line with previous wells which have exceeded our forecasted type curves.

The Company is on track with our focused capital budget of $36 million for the year drilling approximately 9 net ERH wells with the majority being Cardium wells in Willesden Green. The remaining ERH wells are expected to be drilled and brought on production in the second half of 2019. Our 2019 guidance is maintained with annual average production estimated at 4,900 to 5,100 boe/d (approximately 70% oil & liquids) with growth between 6 and 10 percent for oil and liquids, and on a total boe basis, exit production of 5,400 to 5,600 boe/d (70% oil & liquids) with growth between 10 and 14 percent. This guidance is based on realizing an annual average WTI price of $54.00 per bbl (USD), $1.50 per mcf AECO, a foreign exchange ratio of 0.75 CDN/USD and an Edmonton light sweet differential of ($7.50) per bbl (USD). Strengthening WTI crude oil pricing currently at $59 (USD), above our forecast pricing, in addition to the narrowing of Edmonton light sweet differentials to more normalized levels of $4-$6 (USD) are supportive to our capital program matching estimated adjusted funds flow from operations. This program is expected to continue to yield strong returns with anticipated top quartile light oil production growth amongst our light oil weighted peers.

SELECTED QUARTERLY INFORMATION

The following table provides financial and operating results for the last eight quarters. Commodity prices remain volatile, affecting adjusted funds flow from operations and profit (loss) throughout those quarters.

SELECTED QUARTERLY INFORMATION

($ amounts in thousands, except per share amounts)	**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)	1,561
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)
Cash from operating activities	**4,536**	11,638	7,015	7,223
Adjusted funds flow from operations(1)	**1,721**	10,006	7,376	7,938
Adj. funds flow from operations per share, basic and diluted(1)	**0.03**	0.15	0.11	0.12
Net debt(1)	**53,670**	66,005	58,616	53,407

	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Oil and natural gas sales	18,017	14,489	14,584	15,149
Oil and natural gas sales, net of royalties	16,255	12,980	13,171	13,566
Profit (loss)	(6,939)	(2,228)	457	1,010
Profit (loss) per share, basic and diluted	(0.11)	(0.04)	0.01	0.02
Exploration and development capital expenditures	26,992	8,292	4,446	9,511
Property Acquisitions (Dispositions)	(152)	-	1,219	(16)
Cash from (used in) operating activities	6,460	3,659	6,431	6,000
Adjusted funds flow from operations(1)	8,043	4,662	6,171	6,096
Adj. funds flow from operations per share, basic and diluted(1)	0.13	0.08	0.10	0.10
Net debt(1)	51,266	41,950	37,960	37,987

(1) "Net debt", "Adjusted funds flow from operations" and "Adjusted funds flow from operations per share, basic and diluted" are not recognized measures under GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to the "Non-GAAP Measures" section in this Management's Discussion and Analysis for the description and methods of calculation of these Non GAAP Measures and applicable reconciliations to the nearest GAAP measure.

In the first quarter of 2017, 7.0 (5.1 net) wells were drilled of which 3.0 (2.8 net) were awaiting completion and tie in at the end of the quarter. The drilling, completion and equipping program continued into the second quarter of 2017 with the completion of 2.0 gross (1.8 net) wells drilled in the first quarter and starting the drilling of 1.0 gross (1.0 net) well which was completed in the third quarter, in addition to an asset acquisition which closed on June 6, 2017. Into the third quarter of 2017, the remaining 1.0 (1.0 net) well drilled in the first quarter was completed.

A 3.0 (3.0 net) well pad was drilled and completed in the fourth quarter of 2017, along with the drilling of our first East Basin Duvernay Shale horizontal well (1.0 net). Flow-through common shares were issued by the Company in the fourth quarter for proceeds of $10.1 million. A total of $14.1 million was spent acquiring undeveloped land at crown land sales during the fourth quarter of 2017.

InPlay commenced its 2018 program late in 2017. The 2018 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 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.

The Company's drilling program has continued in the first quarter of 2019, drilling an additional 5 (2.7 net) extended reach horizontal wells to date in the first quarter of 2019.

SELECTED ANNUAL INFORMATION

Years ended December 31

(in thousands, except per share amounts)		2018	2017	2016
Total oil and natural gas sales[1]	$	**76,419**	62,239	27,850
Oil and natural gas sales, net of royalties[1]		**68,410**	55,972	25,382
Earnings (loss)		**(8,598)**	(7,701)	20,019
Earnings (loss) per share, basic and diluted		**(0.13)**	(0.12)	1.02
Total assets		**314,021**	323,793	303,409
Total bank loans		**45,400**	44,888	29,755
Total net debt[2]		**53,670**	51,266	34,556

(1) Includes royalty and other income classified with oil and natural gas sales. The oil and natural gas sales exclude realized and unrealized gains and (losses) on risk management derivative contracts: 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; and 2016 excludes $2.7 million realized gain and ($4.8) million unrealized loss.

(2) Net debt is a non-GAAP measure. Refer to "Net debt" in the section entitled "Non-GAAP Measures" at the end of this MD&A.

ADDITIONAL INFORMATION

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

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

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

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

NON-GAAP MEASURES

Included in this document are references to the terms "adjusted funds flow from operations", "adjusted funds flow from operations per share, basic and diluted", "operating income", "operating netback per boe" and "net debt". 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, "net cash flow provided by operating activities", "(loss) before taxes" or "(loss) and comprehensive (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 from Operations

InPlay considers adjusted funds flow from operations to be an important measure of InPlay's ability to generate the funds necessary to finance capital expenditures. Adjusted funds flow from operations should not be considered as an alternative to or more meaningful than net cash flow from operating activities as determined in accordance with GAAP as an indicator of the Company's performance. InPlay's determination of adjusted funds flow from operations may not be comparable to that reported by other companies. All references to adjusted funds flow from operations throughout this MD&A are calculated as net cash flow provided by operating activities adjusting for the impact of operating net change in non-cash working capital and decommissioning expenditures. These items are adjusted from net cash flow provided by operating activities as there is uncertainty with the timing, collection and payment of these items and decommissioning expenditures are incurred on a discretionary and irregular basis, making the exclusion of these items relevant in Management's view to the reader in the evaluation of InPlay's operating performance.

Adjusted Funds Flow from Operations per Share, Basic and Diluted

Adjusted funds flow from operations per share, basic and diluted is calculated by the Company as adjusted funds flow from operations divided by the weighted average number of common shares outstanding for the respective period. Management considers adjusted funds flow from operations per boe an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices.

A reconciliation of net cash flow provided by operating activities to adjusted funds flow from operations and a calculation of adjusted funds flow from operations per share, basic and diluted, is as follows:

	Three months ended December 31		Year ended December 31	
(thousands of dollars)	**2018**	2017	**2018**	2017
Net cash flow provided by operating activities	**4,536**	6,460	**30,411**	22,552
Net change in operating non-cash working capital	**3,095**	(1,190)	**4,611**	(1,778)
Decommissioning expenditures	**(280)**	(393)	**(1,240)**	(644)
Adjusted funds flow from operations	**1,721**	8,043	**27,040**	24,974
Weighted avg. number of common shares (basic and diluted)	**67,987**	63,876	**67,912**	62,688
Adj. funds flow from operations per share, basic and diluted	**0.03**	0.13	**0.40**	0.40

Operating Income

Operating income is calculated by the Company as oil and natural gas sales less royalties, operating expenses and transportation expenses and is a measure of the profitability of operations before administrative, share-based compensation, financing and other non-cash items. Management considers operating income an important measure to evaluate its operational performance as it demonstrates its field level profitability. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure.

Operating Netback per BOE

Operating netback per boe is calculated by the Company as operating income divided by average production for the respective period. 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. Refer to the section entitled "Operating income and netback" within this MD&A for a calculation of this measure.

Net Debt

Net debt is calculated as the amount of outstanding bank loans plus accounts payable and accrued liabilities less accounts receivable and accrued receivables, prepaid expenses and deposits and inventory. See note 19 to the Company's financial statements for the calculations of these measures for the years ended December 31, 2018 and December 31, 2017. InPlay closely monitors working capital and net debt as part of its capital structure with a goal of maintaining a strong financial position in order to fund current operations and future growth.

FORWARD-LOOKING STATEMENTS

This MD&A contains certain forward-looking statements and forward-looking information (collectively referred to herein as "**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;
- expectations regarding InPlay's 2019 forecasted capital expenditures, production estimates including 2019 average and exit forecasts, future operating costs, cash flows and adjusted funds flow from operations;
- the volume and product mix of InPlay's oil and gas production;
- targeted production growth;
- future exchange rate between the $US and $Cdn
- expectations regarding InPlay's tax horizon;
- expectations regarding InPlay's Credit Facility and 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).

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