



Management's Discussion and Analysis

For the three and nine months ended September 30, 2025

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2025 AND SEPTEMBER 30, 2024

The following management's discussion and analysis ("MD&A") is dated November 11, 2025 and should be read in conjunction with the unaudited financial statements of InPlay Oil Corp. ("InPlay" or the "Company") for the three and nine months ended September 30, 2025 and September 30, 2024 and the audited annual financial statements for the years ended December 31, 2024 and December 31, 2023. The financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards"), applicable to the preparation of interim financial statements, including IAS 34 Interim Financial Reporting.

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

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

DESCRIPTION OF BUSINESS

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

PEMBINA ASSET ACQUISITION

On April 7, 2025, the Company closed the previously announced acquisition of Cardium light oil focused assets in the Pembina area of Alberta (the "**Pembina Asset Acquisition**") from Obsidian Energy Ltd. ("**Obsidian**") for consideration of approximately \$291.6 million. Consideration consisted of \$203 million cash payment, the issuance of 9,139,784 common shares of InPlay to Obsidian valued at \$8.58 per share based on the closing price of InPlay shares on April 6, 2025, and the inclusion of InPlay's non-operated assets at Willesden Green Unit 2 (the "**Unit Interest**").

The transaction has been accounted for as a business combination under IFRS 3.

The fair value at April 7, 2025 of the total consideration transferred (net of adjustments) and the amounts recognized attributed to the assets acquired was as follows:

Consideration:	(\$'000s)
Cash consideration	203,489
Share consideration	78,419
Unit Interest	9,656
Total Consideration	291,564
Recognized amounts of assets acquired and liabilities assumed:	
Property, plant and equipment	476,591
Exploration and evaluation	11,628
Right-of-use asset	1,723
Decommissioning obligation	(196,655)
Lease liability	(1,723)
Total identifiable net assets	291,564

During the three months ended September 30, 2025, the acquired amount of Property, plant and equipment was decreased by \$1.7 million as a result of adjustments relating to the acquisition, with a corresponding decrease in the amount of cash consideration.

The fair value of the decommissioning obligation at April 7, 2025 was based on the estimated future cash flows to decommission the acquired property, plant and equipment at the end of its useful life. The discount rate used to determine the net present value of the decommissioning obligation was a credit adjusted risk-free rate of 8.5%. At June 30, 2025 the decommissioning liability was revalued at risk-free discount rates of 2.7% to 3.6%, depending on the estimated timing of the future settlement of the obligations, resulting in incremental additions of \$191.1 million of decommissioning obligation and corresponding additions to property, plant and equipment.

The acquired assets contributed revenues consisting of oil and natural gas sales net of royalties of approximately \$94.9 million and operating income, which is defined as oil and natural gas sales net of royalties less operating and transportation costs, of \$57.3 million to InPlay for the period from April 7, 2025 to September 30, 2025.

For the nine months ended September 30, 2025 \$10.6 million of transaction and integration costs were incurred for advisory and professional fees associated with the transaction.

The fair values of the identifiable assets and liabilities acquired as reported in the table above were estimated based on information available at the time of preparation of the financial statements and could be subject to change.

COMMON SHARE CONSOLIDATION AND COMPARATIVE FIGURES

At the Company's Special Meeting of Shareholders held on April 4, 2025, shareholders approved a six for one common share consolidation effective for shareholders of record as of April 14, 2025. Effective April 14, 2025, shareholders of record received one share for every six common shares held, with common shares trading on a consolidation basis beginning April 17, 2025. Common share, per common share, dividend, stock option, DSU, RSU and PSU amounts for periods prior to the six for one common share consolidation have been updated to reflect the common share consolidation.

REVIEW OF FINANCIAL RESULTS

Production

Average production volumes for the three and nine months ended September 30, 2025 and September 30, 2024 were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Crude oil (bbls/d)	9,122	3,279	7,647	3,467
NGLs (boe/d)	2,334	1,418	2,105	1,448
Natural gas (Mcf/d)	45,081	21,052	38,596	21,446
Total (boe/d) ⁽¹⁾⁽²⁾⁽³⁾	18,970	8,206	16,185	8,489
Crude oil and NGLs (%)	60%	57%	60%	58%

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

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

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

Production for the three and nine months ended September 30, 2025 was 131% and 91% higher, respectively, compared to the three and nine months ended September 30, 2024 as a result of additional production from the Pembina Asset Acquisition and production from the Company's drilling program in the first quarter of 2025. The light oil and liquids weighting for the three and nine months ended September 30, 2025 of 60% and 60%, respectively, improved compared to the three and nine months ended September 30, 2024 as a result of the Acquired Assets having a higher light oil weighting.

InPlay's capital program for first nine months of 2025 consisted of \$40.8 million of development capital. The Company drilled, completed and brought on production four (3.2 net) extended reach horizontal ("ERH") Cardium wells, drilled and completed three (3.0 net) ERH wells that came on production in October and drilled two (2.0 net) wells that are currently being completed. The Company completed a significant operated gas plant expansion and other facility projects. The Company also completed an active well servicing program during the first nine months of 2025 spending \$3.0 million of capital on optimization activities.

Revenues

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Crude oil	69,315	28,659	174,053	91,154
Natural gas	3,093	1,473	15,875	9,551
NGLs	6,939	4,085	19,994	12,969
Total crude oil and natural gas sales ⁽¹⁾	79,347	34,217	209,922	113,674

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

Prices

	Three Months Ended September 30		Nine Months Ended September 30	
Average Realized Price⁽¹⁾	2025	2024	2025	2024
Crude oil (\$/bbl)	82.59	94.99	83.37	95.97
NGLs (\$/boe)	32.31	31.31	34.79	32.70
Natural gas (\$/Mcf)	0.75	0.76	1.51	1.63
Total (\$/boe)	45.47	45.32	47.50	48.87
WTI (\$USD/bbl)	64.93	75.10	66.70	77.54
Edmonton Light Sweet to WTI Diff. (\$USD/bbl)	2.20	3.35	3.34	5.21
CAD/USD Exchange Rate	0.72	0.73	0.71	0.74
AECO (\$/GJ)	0.60	0.65	1.42	1.38

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

In the third quarter of 2025, WTI oil prices decreased 14% averaging \$64.93 US per bbl compared to \$75.10 US per bbl in the third quarter of 2024. In the first nine months of 2025, WTI oil prices decreased 14% averaging \$66.70 US per bbl compared to \$77.54 US per bbl in the first nine months of 2024.

Differentials between WTI oil prices and prices received in Alberta improved in the three and nine months ended September 30, 2025 compared to the same periods in 2024. These differentials can be volatile due to factors including refining demand and pipeline capacity. InPlay sells oil at monthly average Edmonton Par prices less quality differentials, transportation and marketing fees. Light, sweet oil differentials between Cushing, Oklahoma and Edmonton, Alberta are affected by pipeline apportionment, refinery turnarounds, rail capacity and market supply/demand conditions. Monthly index differentials averaged \$2.20 US per barrel discount for the third quarter of 2025 compared to \$3.35 US per barrel discount for the third quarter of 2024. Monthly index differentials averaged \$3.34 US per barrel discount for the first nine months of 2025 compared to \$5.21 US per barrel discount for the same period in 2024.

Realized oil prices are adjusted for the Canada/US exchange rate which decreased averaging 0.72 for the third quarter of 2025 from 0.73 during the third quarter of 2024. The Canada/US exchange rate decreased over the first nine months of 2025 at 0.71 compared to 0.74 over the first nine months of 2024.

Due to the items noted above, realized oil prices for the three and nine months ended September 30, 2025 decreased compared to the three and nine months ended September 30, 2024. The Company's average net realized price for crude oil was \$82.59 per bbl for the third quarter of 2025, 13% lower than the third quarter 2024 realized price of \$94.99 per bbl. The Company's average net realized price for crude oil was \$83.37 per bbl for the first nine months of 2025, 13% lower than the first nine months of 2024 realized price of \$95.97 per bbl.

Natural gas prices remain at historically low levels. In the third quarter of 2025, natural gas AECO daily index prices decreased 8% averaging \$0.60 per GJ compared to \$0.65 per GJ in the third quarter of 2024. In the first nine months of 2025, natural gas AECO daily index prices increased 3% averaging \$1.42 per GJ compared to \$1.38 per GJ in the first nine months of 2024.

The Company's average realized natural gas sales price was \$0.75 per Mcf for the third quarter of 2025, 1% lower than \$0.76 per Mcf realized in the third quarter of 2024. The Company's average realized natural gas sales price was \$1.51 per Mcf for the nine months ended September 30, 2025, decreasing by 7% compared to \$1.63 per Mcf in the first nine months of 2024.

Realized NGL pricing improved for the three months ended September 30, 2025 compared to the same period in 2024. The Company's average realized NGL price was \$32.31 per boe for the second quarter of 2025, 3% higher than \$31.31 per boe realized in the third quarter of 2024. The Company's average realized NGL sales price was \$34.79 per boe for the first nine months of 2025, improving by 6% when compared to the first nine months of 2024 realized price of \$32.70 per boe.

Royalties

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Total royalties (\$'000s)	12,436	5,122	29,005	14,711
Total royalties (% of sales)	15.7%	15.0%	13.8%	12.9%
Total royalties (\$/boe)	7.13	6.78	6.56	6.33

Royalties during the three and nine months ended September 30, 2025 remained relatively flat on a per boe basis compared to the same periods in 2024, tracking revenue and commodity prices. Royalties on an absolute basis increased as a result of additional production from the Pembina Asset Acquisition. Royalties on a percentage of revenue basis increased due to new wells drilled in the first quarter of 2025 coming off of the royalty holiday period early given the strong performance of these wells.

Derivative contracts

The Company's production is predominantly sold using near-term contracts with complementary spot sales as needed, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company may selectively enter into commodity derivative contracts in order to hedge a portion of oil and

natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts.

At September 30, 2025, commodity-based derivative contracts totaling the amounts below were outstanding and recorded at estimated fair value:

	Q4/25	Q1/26	Q2/26	Q3/26	Q4/26	Q1/27
Natural Gas AECO Swap (mcf/d)	15,800	15,165	14,215	14,215	8,560	4,265
Hedged price (\$AECO/mcf)	\$2.65	\$2.85	\$3.00	\$3.00	\$3.05	\$3.65
Natural Gas AECO Costless Collar (mcf/d)	12,640	12,320	11,375	11,375	16,400	18,950
Hedged price (\$AECO/mcf)	\$2.20 - \$3.40	\$2.25 - \$3.50	\$2.45 - \$3.50	\$2.45 - \$3.50	\$2.80 - \$4.40	\$2.90 - \$4.85
Crude Oil WTI Swap (bbl/d)	2,500	3,750	2,000	2,000	2,000	2,000
Hedged price (\$USD WTI/bbl)	\$62.20	\$60.30	\$60.90	\$60.90	\$61.05	\$61.05
Crude Oil WTI Costless Collar (bbl/d)	2,300	-	-	-	-	-
Hedged price (\$USD WTI/bbl)	\$56.30 - \$62.70	-	-	-	-	-
Crude Oil WTI Three-way Collar (bbl/d)	1,300	1,000	2,500	1,750	1,750	-
Low sold put price (\$USD WTI/bbl)	\$59.50	\$50.00	\$50.00	\$50.00	\$50.00	-
Mid bought put price (\$USD WTI/bbl)	\$67.50	\$57.50	\$57.50	\$57.50	\$57.50	-
High sold call price (\$USD WTI/bbl)	\$83.00	\$72.10	\$71.95	\$72.15	\$72.15	-
Electricity AESO Swap (kW)	1,000	1,000	1,000	1,000	1,000	1,000
Hedged price (\$kWh)	\$0.06217	\$0.06217	\$0.06217	\$0.06217	\$0.06217	\$0.06217

Subsequent to September 30, 2025, the Company entered into the following hedges:

Type of contract: average forward rate swap (USD/CAD):

Reference currency	USD Amount (\$'000s)	Average forward swap rate (USD/CAD)	Term
US Dollar	2,000	1.379	Jan. 1, 2026 – June 30, 2026
US Dollar	8,000	1.388	October 1, 2025 – December 31, 2025

Type of contract: costless collar (USD/CAD):

Reference currency	USD Amount (\$'000s)	Bought put rate (USD/CAD)	Sold call rate (USD/CAD)	Term
US dollar	2,000	1.35	1.40	Jan. 1, 2026 – June 30, 2026

Type of contract: variable rate collar (USD/CAD):

Reference currency	USD Amount (\$'000s)	Put Strike rate	Restrike rate	Call Strike rate	Term
US dollar	3,750	1.35	1.38	1.40	July 1, 2026 – Dec. 31, 2026

Operating expenses

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Total operating expenses (\$'000s)	30,728	12,085	70,977	35,786
Total operating expenses (\$/boe)	17.61	16.01	16.06	15.39

Operating expenses include expenses incurred to operate wells, gather and treat production volumes as well as costs to perform well and facility repairs and maintenance. For the three months ended September 30, 2025, operating expenses per boe were \$17.61 per boe compared to \$16.01 per boe for the same period in 2024. For the nine months ended September 30, 2025, operating expenses per boe were \$16.06 per boe compared to \$15.39 per boe for the same period in 2024. Operating expenses on an absolute basis increased as a result of additional production from the Pembina Asset Acquisition. Operating expenses on a per boe basis increased due to additional well servicing, additional facility maintenance associated with turnarounds and approximately \$1.0 million of one time prior period costs being recognized during the quarter.

Transportation expenses

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Total transportation expenses (\$'000s)	1,513	667	3,759	2,296
Total transportation expenses (\$/boe)	0.87	0.88	0.85	0.99

Transportation expenses include costs incurred to transport processed crude oil, liquids and natural gas products to the point of sale, as well as firm-service take or pay contracts that InPlay has secured directly to transport its natural gas. Expenses incurred to transport production that is not yet in a suitable condition to be shipped on a common-carrier pipeline from the well or battery to a cleaning facility or fractionation plant are included within operating expenses.

For the quarter ended September 30, 2025, transportation expenses were \$0.87 per boe and decreased in comparison to \$0.88 per boe for the quarter ended September 30, 2024. For the nine months ended September 30, 2025, transportation expenses were \$0.85 per boe and also decreased in comparison to \$0.99 per boe for the nine months ended September 30, 2024. This decrease was due to additional production from the Pembina Asset Acquisition being tied-in by pipelines. Transportation expenses on an absolute basis increased as a result of additional production from the Pembina Asset Acquisition.

Operating Income and Netback

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Revenue ⁽¹⁾	79,347	34,217	209,922	113,674
Royalties	(12,436)	(5,122)	(29,005)	(14,711)
Operating expenses	(30,728)	(12,085)	(70,977)	(35,786)
Transportation expenses	(1,513)	(667)	(3,759)	(2,296)
Operating income ⁽²⁾	34,670	16,343	106,181	60,881
Sales volume (Mboe)	1,745.2	755.0	4,418.6	2,325.9
Per boe (\$)				
Revenue ⁽¹⁾	45.47	45.32	47.50	48.87
Royalties	(7.13)	(6.78)	(6.56)	(6.33)
Operating expenses	(17.61)	(16.01)	(16.06)	(15.39)
Transportation expenses	(0.87)	(0.88)	(0.85)	(0.99)
Operating netback per boe ⁽²⁾	19.86	21.65	24.03	26.16
Operating income profit margin ⁽²⁾	44%	48%	51%	54%

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

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

Operating netback per boe decreased slightly for the three and nine months ended September 30, 2025 compared to the three and nine months ended September 30, 2024 reflecting the decreases to realized commodity prices over these periods. Operating income on an absolute basis increased as a result of additional production from the Pembina Asset Acquisition.

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 after capitalized G&A and recoveries:

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Gross G&A expenditures	5,450	3,083	14,303	9,015
Capitalized and recoveries	(1,691)	(600)	(3,634)	(1,856)
General and administrative expenses	3,759	2,483	10,669	7,159
G&A expenses (\$/boe)	2.15	3.29	2.41	3.08
% Capitalized and recoveries	31%	19%	25%	21%

For the quarter ended September 30, 2025, G&A expenses were \$3.8 million (\$2.15 per boe) compared to \$2.5 million (\$3.29 per boe) for the same period in 2024. For the nine months ended September 30, 2025, G&A expenses were \$10.7 million (\$2.41 per boe) compared to \$7.2 million (\$3.08 per boe) for the same period in 2024. Lower G&A expenses on a per boe basis in the third quarter and first nine months of 2025 in comparison to the same periods in 2024 are a result of G&A expenses being incurred over a larger production base. G&A expenses on an absolute basis increased as a result of increased payroll and other administrative costs as a result in the increased scale of the Company after the Pembina Asset Acquisition.

Share-based compensation expenses

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

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Share-based compensation	1,112	769	5,674	3,130
Capitalized portion	(227)	(183)	(1,331)	(721)
Share-based compensation expense	885	586	4,343	2,409

For the quarter ended September 30, 2025, share-based compensation expense was \$0.9 million compared to \$0.6 million for the same period in 2024. For the nine months ended September 30, 2025, share-based compensation expense was \$4.3 million compared to \$2.4 million for the same period in 2024. Share-based compensation expenses were higher in the third quarter and first nine months of 2025 due to additional share-based compensation as a result of the number of units granted to new employees added after the Pembina Asset Acquisition and vesting profiles of options, RSUs and PSUs granted in 2025.

During the nine months ended September 30, 2025, 379,833 options were granted, 106,783 options were exercised and 8,300 options were forfeited.

At September 30, 2025, the maximum number of stock options available for grant was 2,783,834 and 704,197 stock options were outstanding.

In 2022, the Company implemented a Restricted and Performance Award Incentive Plan (“**RPAP**”) under which Restricted Awards (“**RAs**”) and Performance Awards (“**PAs**”) may be granted to directors, officers, employees, consultants or other service providers of the Company. Each RA and PA entitles the holder to an award value vesting generally over a three-year period. The award value of PAs is adjusted for a payout multiplier which can range from 0.0 to 2.0 and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. A payout multiplier of 1.0 was approved by the Board of Directors for 2022. A payout multiplier of 1.4 was approved by the Board of Directors for 2023. A payout multiplier of 1.4 was approved by the Board of Directors for 2024. The corporate performance measures are based upon certain financial and operating results of the Company as pre-determined by the Board, including shareholder returns relative to the Company's peer group, leverage ratios, adjusted funds flow per share in excess of capital expenditures, reserve recycle ratios, production per share growth and execution of the Company's corporate strategy. The Company, at its discretion, is eligible to settle the award value of vesting RAs and PAs either in cash or in common shares acquired by an independent trustee in the open market. The RPAP includes a value make whole provision to all RA and PA holders when dividends are issued to shareholders. The dividend equivalent provision compensates RA and PA holders with additional RAs or PAs equal to the value of the dividends paid on a per unit basis on the dividend payment date.

The movements of outstanding RAs and PAs during the nine months ended September 30, 2025 and the year ended December 31, 2024 were as follows:

	Number of RAs	Number of PAs
Outstanding at December 31, 2023	214,723	130,693
Granted during the period	4,833	-
Dividend make-whole adjustment	17,754	10,612
Vested during the period	(744)	-
Forfeited during the period	-	29,993
Outstanding at December 31, 2024	236,566	171,298
Granted during the period	564,856	526,688
Dividend make-whole adjustment	46,098	40,439
Vested during the period	(240,697)	(196,853)
Payout multiplier adjustment	-	64,665
Forfeited during the period	(11,520)	(3,187)
Outstanding at September 30, 2025	595,303	603,050

Depletion and depreciation

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Depletion and depreciation (\$'000s)	28,496	11,610	71,195	35,096
Depletion and depreciation (\$/boe)	16.33	15.38	16.11	15.09

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

Depletion and depreciation was \$28.5 million (\$16.33 per boe) for the quarter ended September 30, 2025 compared to \$11.6 million (\$15.38 per boe) for the same period in 2024. Depletion and depreciation was \$71.2 million (\$16.11 per boe) for the nine months ended September 30, 2025 compared to \$35.1 million (\$15.09 per boe) for the same period in 2024. Depletion and depreciation on an absolute basis increased as a result of the increased Property, plant and equipment assets and increased production from the Pembina Asset Acquisition.

Impairment

At September 30, 2025 there were no indicators of impairment. All previously recorded impairments have been fully reversed.

Indicators of impairment relating to Property, plant and equipment were considered to exist as at December 31, 2024 as the Company's net assets were greater than its market capitalization. An impairment test was performed for the Company's CGU which did not result in an impairment loss being recorded in the Company's statements of profit and comprehensive income. The Company measured the fair value less costs of disposal of the CGU whereby the net present value of the after tax future cash flows were calculated using a discount rate of 13%. 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, expected future rates of production, future commodity prices, operating expenses, and future development costs.

If the discount rate used was one percent higher, no impairment would have been recorded for the year ended December 31, 2024. If the commodity prices used in the impairment tests were five percent lower, no

impairment would have been recorded for the year ended December 31, 2024.

The following table shows the benchmark commodity prices used in the impairment calculation of Property, plant and equipment at December 31, 2024 of which is based on an average of independent reserve evaluator pricing estimates.

	Light, Sweet Crude Edmonton (\$Cdn/bbl)	AECO Gas Price (\$Cdn/MMBtu)
Year	December 31, 2024	December 31, 2024
2025	71.58	2.36
2026	74.48	3.33
2027	75.81	3.48
2028	77.66	3.69
2029	79.22	3.76
2030	80.80	3.83
2031	82.42	3.91
2032	84.06	3.99
2033	85.74	4.07

At September 30, 2025 there were no indicators of impairment relating to the Company's Exploration and evaluation assets.

Finance expenses

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Interest expense (Credit Facility and other)	5,920	1,402	12,572	4,326
Interest expense (Lease liabilities)	65	320	743	975
Accretion on decommissioning obligations	3,429	761	8,336	2,219
Finance expense	9,414	2,483	21,651	7,520

Finance expenses were \$9.4 million for the third quarter of 2025, compared to \$2.5 million in the third quarter of 2024. Finance expenses were \$21.7 million for the nine months ended September 30, 2025, compared to \$7.5 million during the same period in 2024. Finance expenses increased for the three and nine months ended September 30, 2025 as a result of higher accretion costs relating to the decommissioning obligations acquired in the Pembina Asset Acquisition and higher debt levels after closing of the Pembina Asset Acquisition.

Income taxes

The Company has recognized a deferred tax asset of \$18.4 million at September 30, 2025. The Company recognized deferred income tax recovery of \$1.4 million during the three months ended September 30, 2025 and deferred income tax recovery of \$2.4 million during the nine months ended September 30, 2025.

The deferred tax asset is supported by the expected future utilization of tax attributes based upon future cashflows derived from the Company's updated forecasts and independent year end reserve report using the total proved cashflows and expenditures and factoring in expected corporate general and administrative and interest expenses. As a result of changes in these future cashflows, deferred income tax expense was debited by \$0.6 million during the nine months ended September 30, 2025 (September 30, 2024 - \$0.1 million credit) with a corresponding impact to the deferred income tax asset. At September 30, 2025, the Company had \$2.9 million of unrecognized deferred tax asset (December 31, 2024 - \$2.3 million).

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at September 30, 2025.

(thousands of dollars)

Non-capital loss carryforward balances	125,788
Share issue costs	1,666
Canadian Exploration Expenses (CEE)	56,750
Canadian Development Expenses (CDE)	96,612
Canadian Oil and Gas Property Expenses (COGPE)	295,465
Undepreciated Capital Cost (UCC)	92,280
Total	668,561

ADJUSTED FUNDS FLOW

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Funds flow	24,781	12,177	70,186	47,580
Transaction and integration costs	477	-	10,618	-
Decommissioning expenditures	1,542	927	2,861	2,194
Adjusted funds flow⁽¹⁾	26,800	13,104	83,665	49,774

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

Adjusted funds flow for the three and nine months ended September 30, 2025 was \$26.8 million and \$83.7 million, respectively, compared to \$13.1 million and \$49.8 million for the three and nine months ended September 30, 2024. Adjusted funds flow increased as a result of additional production from the Pembina Asset Acquisition, partially offset by lower realized prices in 2025 compared to 2024.

CAPITAL EXPENDITURES

Capital expenditures for the three months ended September 30, 2025 were \$22.3 million of development capital. Capital expenditures for the nine months ended September 30, 2025 were \$40.8 million of development capital and \$293.6 million primarily related to the Pembina Asset Acquisition. The breakdown of capital expenditures is shown below:

(thousands of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	2024	2025	2024
Drilling & completions	12,740	16,913	22,618	39,863
Facilities and equipping costs, net of dispositions	7,901	3,240	13,005	7,278
Well optimization	887	1,515	2,956	4,419
Total development capital	21,528	21,668	38,579	51,560
Office and Capitalized G&A	731	409	2,087	1,410
Capital expenditures – PP&E	22,259	22,077	40,666	52,970
Land and lease	46	24	140	78
Exploratory drilling	-	3,077	-	3,816
Capital expenditures – PP&E and E&E	22,305	25,178	40,806	56,864
Property acquisitions (dispositions)	(1,710)	(13)	291,907⁽¹⁾	(37)
Total capital expenditures	20,595	25,165	332,713	56,827

(1) Includes total consideration for the Pembina Asset Acquisition including cash consideration of \$203.5 million, share consideration of \$78.4 million and Unit Interest of \$9.7 million.

InPlay's capital program for first nine months of 2025 consisted of \$40.8 million of development capital. The Company drilled, completed and brought on production four (3.2 net) extended reach horizontal ("ERH") Cardium wells, drilled and completed three (3.0 net) ERH wells that came on production in October and drilled two (2.0 net) wells that are currently being completed. The Company completed a significant operated gas plant expansion and other facility projects. The Company also completed an active well servicing program during the first nine months of 2025 spending \$3.0 million of capital on optimization activities.

Drilling statistics are shown below:

	Three months ended September 30				Nine Months Ended September 30			
	2025		2024		2025		2024	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	6	5.2	6	6.0	9	8.2	15	12.6
Natural gas	-	-	-	-	-	-	-	-
Dry	-	-	-	-	-	-	-	-
Total	6	5.2	6	6.0	9	8.2	15	12.6
Success rate	100%	100%	100%	100%	100%	100%	100%	100%

SHARE INFORMATION

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

As of November 11, 2025, there were 27,838,349 common shares outstanding, which excludes 110,636 common shares held in trust for the potential future settlement of awards issued under the Company's Restricted and Performance Award Incentive Plan, and an additional 704,197 stock options that, subject to vesting, are convertible into, or exercisable or exchangeable for, an equivalent number of common shares of the Company. In addition, there were 595,303 RAs and 603,050 PAs outstanding.

The Company periodically provides funds to an independent trustee to acquire common shares in the open market, which are held in trust for the potential future settlement of Restricted and Performance award values. The common shares held in trust are netted out of share capital, including the cumulative purchase cost, until they are distributed for future settlements. For the nine months ended September 30, 2025, the independent trustee purchased 237,522 common shares for a total cost of \$2.1 million and as at September 30, 2025, the independent trustee held 110,636 common shares in trust.

The Company's Board of Directors approved the implementation of a monthly base cash dividend of \$0.015 per share (\$0.09 per share post 6:1 share consolidation) commencing in November 2022 which resulted in the payment of \$19.5 million in dividends during the nine months ended September 30, 2025 (September 30, 2024 - \$12.3 million). The issuance of the monthly base dividend is subject to the discretion of the Board of Directors.

Subsequent to September 30, 2025, the Board of Directors approved and declared monthly cash dividends of \$0.09 per share, designated as eligible dividends, payable to shareholders of record on October 15, 2025 and November 14, 2025. The dividend payment date for these dividends is October 31, 2025 and November 28, 2025.

RELATED PARTY TRANSACTIONS

InPlay had no related party transactions that were entered into under the normal course of business for the three and nine months ended September 30, 2025 and September 30, 2024.

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, sustain the future development of the business and continue to provide a dividend to its shareholders. 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.

Concurrent with completion of the Acquisition on April 7, 2025, InPlay entered into an amended and restated credit agreement with a syndicate of lenders (the "**Lenders**") pursuant to which the aggregate available borrowing capacity under InPlay's Senior Credit Facility was increased from \$110 million to \$330 million by way of an increased \$190 million revolving credit facility (the "**Revolving Credit Facility**") with a term out date extended to September 30, 2026, a \$110 million two-year amortizing term loan (the "**Term Facility**") and a letter of credit facility of up to \$30 million, which was subsequently reduced to \$5.5 million upon the required placement of a letter of credit in the third quarter of 2025.

Revolving Credit Facility

The Revolving Credit Facility consists of a \$140 million revolving line of credit and a \$50 million operating line of credit. The Revolving Credit Facility has a term out date of September 30, 2026, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable one year later on September 30, 2027. The Revolving Credit Facility is secured by a floating charge debenture of \$150 million and a general security agreement on the assets of the Company. At September 30, 2025, the Company had drawn \$121.1 million on the Revolving Credit Facility. There are standard reporting covenants under the Revolving Credit Facility and no financial covenants. In addition, there is an additional affirmative covenant to satisfy certain prescribed hedging requirements under the Revolving Credit Facility. The Company was in compliance with these covenants as at September 30, 2025.

Under the Revolving Credit Facility, advances can be drawn as prime rate loans and bear interest at the bank's prime lending rate plus interest rates between 2.00% and 5.50%. Advances may also be drawn as Canadian Overnight Repo Rate Average ("CORRA") loans, Secured Overnight Finance Rate ("SOFR") loans, and letters of credit, subject to the CORRA rate plus margins ranging from 3.00% to 6.50%. These interest rates, fees and margins vary based on adjusted debt to earnings metrics determined at each quarter end for the preceding 12 months.

The available lending limit of the Revolving Credit Facility is scheduled for semi-annual renewal on or before November 30, 2025 and is based on the Lenders' interpretation of the Company's oil and natural gas reserves and future commodity prices. There can be no assurance that the amount or terms of the Revolving Credit Facility will not be adjusted at the next semi-annual review. In the event that the lenders reduce the borrowing base under the Revolving Credit Facility below the amount drawn at the time of the redetermination, the Company would have 60 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the Revolving Credit Facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

Term Facility

The Term Facility has a maturity date of April 7, 2027 and is secured by a floating charge debenture of \$150 million and a general security agreement on the assets of the Company. The Term Facility includes quarterly amortization payments of \$4.1 million and quarterly payments equating to 50% of excess cash flow as defined by the Term Facility credit agreement. The \$110 million Term Facility was fully drawn upon of the Acquisition. At September 30, 2025, \$102.1 million was drawn on the Term Facility. The covenant and security package under the Term Facility is substantially the same as the Revolving Credit Facility, with the exception of the Term Facility having a Debt to Earnings before interest, taxes, depreciation and amortization ("EBITDA") covenant whereby this ratio is not to exceed 2.00:1.00, and a fixed charge coverage ratio covenant whereby this ratio is not to exceed 1.75:1.00. The Company was in compliance with these standard reporting covenants and financial covenants as at September 30, 2025.

Under the Term Facility, advances can be drawn as prime rate loans and CORRA loans and bear interest at the

bank's applicable prime lending or CORRA loan rates plus margins ranging from 2.25% to 3.75% of which these margins are dependent upon amounts drawn on the Term Facility.

In addition to the amount drawn on the Credit Facilities at September 30, 2025, the Company had a current assets (excluding derivative contracts) less accounts payable and accrued liabilities deficit of \$5.2 million.

OFF-BALANCE SHEET ARRANGEMENTS

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

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. At September 30, 2025, these obligations include:

- **Loan agreements** – The Revolving Credit Facility has a term out date of September 30, 2026 and, if not extended, any outstanding balances would have become repayable one year later on September 30, 2027. The Term Facility has a maturity date of April 7, 2027. Refer to the "Liquidity and Capital Resources" section for more information.
- **Firm service transportation commitments** – The Company has entered into firm service transportation agreements. Fees related to transportation periods subsequent to September 30, 2025 were not recognized as a liability at September 30, 2025.

As at September 30, 2025 the Company had the following minimum contractual obligations:

Contractual obligations (in thousands of dollars)	2025	2026	2027	2028	2029+
Accounts payable	64,355	-	-	-	-
Credit facilities - principal ⁽¹⁾⁽²⁾	4,125	16,500	202,547	-	-
Credit facilities - interest ⁽³⁾⁽⁴⁾	5,543	20,971	7,933	-	-
Lease liability	682	2,951	1,784	506	858
Firm service	721	3,911	2,589	1,208	1,142
Gas processing	861	3,486	3,555	3,636	-
Total	76,287	47,819	218,408	5,350	2,000

⁽¹⁾ Assumes the Revolving Credit Facility is not renewed on September 30, 2026, whereby outstanding balances become due one year later on September 30, 2027.

⁽²⁾ Assumes quarterly amortization payments of \$4.1 million are made against the Term Facility with the remaining amount repaid on April 7, 2027. These quarterly amortization payments are made through additional draws on the Revolving Credit Facility.

⁽³⁾ Assumes interest is incurred on amounts outstanding on the Revolving Credit Facility at September 30, 2025 at the Company's effective interest rate during the current quarter and the principal balance is repaid September 30, 2027.

⁽⁴⁾ Assumes interest is incurred on amounts outstanding on the Term Facility at September 30, 2025, with quarterly amortization payments of \$4.1 million, at the Company's effective interest rate during the current quarter and the remaining principal balance is repaid April 7, 2027.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 3 to the Company's unaudited interim financial statements for the three and nine months ended September 30, 2025. 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 commodity prices and operating costs, expected future rates of production and timing and amount of future capital expenditures. By their nature, these estimates are subject to measurement uncertainties and interpretations and the impact on the financial statements could be material. The Company expects that over time, its reserves estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels and may be affected by changes in commodity prices.

Recoverable amounts of CGUs

The recoverable amount of a CGU used in the assessment of impairment is the greater of its value-in-use ("VIU") and its fair value less costs to sell ("FVLCTS"). VIU is determined by estimating the present value of the future net cash flows from the continued use of the CGU, and is subject to the risks associated with estimating the value of reserves. FVLCTS refers to the amount obtainable from the sale of a CGU in an arm's length transaction between knowledgeable, willing parties, less costs of disposal. The criteria used in the estimation of this amount are discussed in note 4 to the audited annual financial statements for the years ended December 31, 2024 and December 31, 2023.

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.

Business combinations

The amounts recorded for identifiable assets acquired, liabilities assumed, goodwill or a gain from a bargain purchase will depend on management's assumptions and estimates of future events, in particular, those assumptions and estimates used in the estimation of the fair value of oil and natural gas reserves. Key assumptions developed by management used to determine the fair value of the PP&E assets acquired included the discount rates, expected future rates of production, future commodity prices, operating expenses, and development costs.

Management applies significant judgment in estimating the fair value of the PP&E assets acquired in a business combination. To estimate the fair value of the PP&E assets, management uses a discounted future cash flow model to determine the net present value of after tax future cash flows from the oil and natural gas reserves. The fair values of identifiable assets and liabilities acquired are estimated based on information available at the time of preparation of the financial statements and could be subject to change.

CHANGES IN ACCOUNTING POLICIES

There were no new or amended accounting standards or interpretations adopted in the nine months ended September 30, 2025.

The Company has reviewed the following reporting and accounting standards that have been issued, but are not yet effective:

IFRS 18 "Presentation and Disclosure in Financial Statements"

The IASB has issued IFRS 18 – Presentation and Disclosure in Financial Statements to achieve comparability of the financial performance of similar entities. The standard, which replaces IAS 1, impacts the presentation of primary financial statements and notes, mainly the income statement where companies will be required to present separate categories of income and expense for operating, investing, and financing activities with prescribed subtotals for each new category. IFRS 18 will require management-defined performance measures to be explained and included in a separate note within the financial statements. The standard is effective for financial statements beginning on January 1, 2027, including interim financial statements and requires retrospective application. The Company is currently assessing the impact of this standard.

IFRS 7 "Financial Instruments" & IFRS 9 "Financial Instruments: Disclosures"

On May 30, 2024, the IASB issued amendments to IFRS 9, "Financial Instruments", and IFRS 7, "Financial Instruments: Disclosures". The amendments include clarifications on the derecognition of financial liabilities and the classification of certain financial assets. In addition, new disclosure requirements for equity instruments designated as fair value through other comprehensive income were added. The amendments are effective for annual periods beginning on or after January 1, 2026, and is to be applied retrospectively. The Company is currently assessing the impact of this standard.

CONTROLS AND PROCEDURES

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that:

(i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on July 1, 2025 and ended on September 30, 2025 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, aggression by Russia towards Ukraine and other neighbouring nations, the war in the Middle East, and the actions, including sanctions, taken by NATO nations against this aggression, U.S. tariffs, counter tariffs and support for existing treaty and trade relationships, the US dollar exchange rate, transportation costs, political stability, Indigenous land claims, inflation and rising interest rates 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 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. Current areas of geopolitical risk include: Russia's military invasion of Ukraine; and rising civil unrest and activism globally. 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, cyber security risks, 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 regulatory approval process and the requirements for extensive landowner consultation.

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

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

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

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

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

Based on the Company's current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict the Company's ability to access its properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous

working conditions. Certain of the Company's assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to the Company's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

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

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

The election of President Trump in the U.S. may result in legislative and regulatory changes that could have an adverse effect on InPlay and its financial condition. In particular, there is uncertainty regarding the newly implemented U.S. tariffs and support for existing treaty and trade relationships, including with Canada. Implementation by the U.S. government of new legislative or regulatory policies could impose additional costs on InPlay, decrease U.S. demand for InPlay's products, or otherwise negatively impact InPlay, which may have a material adverse effect on InPlay's business, financial condition and operations. In addition, this uncertainty may adversely impact: (i) the ability of companies to transact business with companies such as InPlay; (ii) InPlay's profitability; (iii) regulation affecting the Canadian oil and gas industry; (iv) global stock markets (including the TSX); and (v) general global economic conditions. All of these factors are outside of InPlay's control but may nonetheless lead InPlay to adjust its strategy in order to compete effectively in global markets.

OUTLOOK

During the third quarter, InPlay continued to build on the momentum generated by its April 7, 2025 acquisition of Cardium-focused light oil assets in the Pembina area of Alberta (the "**Acquisition**"). Due to the outperformance of base production and material outperformance of our 2025 drilling program, current production rates are ahead of forecast at 19,750 boe/d (61% light oil and NGLs), with two (2.0 net) operated ERH wells scheduled to come onstream in the next week. As a result, InPlay is increasing its 2025 average annual production guidance to 16,900 boe/d – 17,100 boe/d⁽¹⁾ (60% - 62% light oil and NGLs), up 4% from the mid-point of the previous guidance range of 16,000 boe/d – 16,800 boe/d⁽¹⁾ (60% - 62% light oil and NGLs).

The third quarter marked InPlay's most active capital program of the year, as the Company advanced the development of its expanded inventory of high-quality locations. InPlay drilled six (5.2 net) wells in Pembina during the third quarter. Three (3.0 net) of these wells were completed through quarter end and brought on production in mid-October and two (2.0 net) wells are currently being completed and are expected to be brought on production in mid-November. The Company also participated in one (0.2 net) non-operated well, which was drilled, completed, and brought on production in September.

InPlay's 2025 drilling program is now complete, with 8.2 net wells drilled this year, with an additional 4.0 net wells drilled on the acquired assets in the first quarter. InPlay's disciplined approach in this focused area has

resulted in strong capital efficiencies, with forecasted 2025 exploration and development expenditures expected to be approximately \$53 million, at the lower end of our previous guidance range of \$53 - \$60 million. This includes the acceleration of our 2026 capital program by building three leases and initiating drilling operations on our first 2026 planned well before year-end. With the majority of capital spending completed by the end of October, and new wells coming online from the third and fourth quarter, InPlay expects to deliver strong free adjusted funds flow ("FAFF")⁽³⁾ in the fourth quarter.

Notes:

1. See table in the Reader Advisories for key budget and underlying material assumptions related to the Company's 2025 capital program and associated guidance.
2. See "Production Breakdown by Product Type"
3. Capital management measure. See "Non-IFRS and Other Financial Measures" contained within this MD&A.
4. Non-IFRS measure or ratio that does not have a standardized meaning under International Financial Reporting Standards (IFRS) and GAAP and therefore may not be comparable with the calculations of similar measures for other companies. Please refer to "Non-GAAP and Other Financial Measures" within this MD&A for details of calculations, rationale for use and applicable reconciliation to the nearest IFRS measure.

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 throughout those quarters.

(\$ amounts in thousands, except per share amounts)	Q3 2025	Q2 2025	Q1 2025	Q4 2024
Oil and natural gas sales	79,347	91,639	38,936	40,039
Oil and natural gas sales, net of royalties	66,911	79,844	34,162	34,786
Profit (loss)	(4,803)	(3,194)	(2,887)	2,220
Profit (loss) per share, basic	(0.17)	(0.12)	(0.19)	0.12
Profit (loss) per share, diluted	(0.17)	(0.12)	(0.18)	0.12
Capital expenditures – PP&E	22,259	4,571	13,836	6,191
Capital expenditures – E&E	46	42	52	13
Property acquisitions (dispositions)	(1,710)	293,247	343	-
Adjusted funds flow ⁽²⁾	26,800	40,080	16,782	18,749
Adjusted funds flow per share, basic ⁽³⁾	0.96	1.49	1.10	1.26
Adjusted funds flow per share, diluted ⁽³⁾	0.96	1.49	1.06	1.20
Adjusted funds flow per boe ⁽³⁾	15.36	21.59	20.54	21.74
Net debt ⁽²⁾	228,409	223,223	63,286	60,895
	Q3 2024	Q2 2024	Q1 2024	Q4 2023
Oil and natural gas sales	34,217	41,460	37,997	47,631
Oil and natural gas sales, net of royalties	29,096	36,396	33,471	41,292
Profit	146	5,415	1,686	11,576
Profit per share, basic	0.01	0.36	0.11	0.78
Profit per share, diluted	0.01	0.36	0.11	0.78
Capital expenditures – PP&E	22,077	5,389	25,504	14,590
Capital expenditures – E&E	3,101	767	26	42
Property acquisitions (dispositions)	(13)	-	(25)	-
Adjusted funds flow ⁽²⁾	13,104	20,145	16,525	23,544
Adjusted funds flow per share, basic ⁽³⁾	0.90	1.32	1.08	1.56
Adjusted funds flow per share, diluted ⁽³⁾	0.84	1.32	1.08	1.56
Adjusted funds flow per boe ⁽³⁾	17.36	25.57	21.10	26.67
Net debt ⁽²⁾	68,021	50,841	59,897	45,679

⁽¹⁾ Quarterly amounts may not add to equal the total annual amounts due to rounding.

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

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

InPlay's capital program for 2023 consisted of \$84.5 million of development capital. The Company drilled, completed and brought on production 12 (10.5 net) extended reach horizontal ("ERH") wells in Willesden Green, five (5.0 net) ERH wells in Pembina, one (1.0 net) multilateral Belly River well and three (0.6 net) non-operated Willesden Green ERH wells during this period. This activity amounted to the drilling of 21 gross (17.1 net) wells for an equivalent of 30 gross horizontal miles (24.2 net horizontal miles). During 2023 InPlay also completed two natural gas facility upgrades in Willesden Green to reduce our reliance on 3rd party facilities to improve run time, alleviate back pressure on producing wells and increase natural gas capacity to allow for future development in the area.

InPlay's capital program for 2024 consisted of \$63.1 million of exploration and development capital. The Company drilled, completed and brought on production two (1.9 net) extended reach horizontal ("ERH") wells in Willesden Green, two (2.0 net) one-mile horizontal wells in Willesden Green, three (3.0 net) ERH wells in Pembina, four (4.0 net) Pembina Cardium Unit #7 ERH wells, one (1.0 net) Belly River well, and three (0.65 net) non-operated Willesden Green ERH wells during 2024. This activity amounted to the drilling of 15 gross (12.6 net) wells. Additionally, the Company incurred drilling costs on one (1.0 net) Glaucinite well where drilling challenges resulted in casing failure and led to the termination of drilling operations. InPlay is currently evaluating options for this well. In addition, approximately \$5.4 million was spent on the optimization of wells during 2024 on changing plunger lifts to downhole pumps and lowering pumps in horizontal wells.

On April 7, 2025, the Company closed the previously announced acquisition of Cardium light oil focused assets in the Pembina area of Alberta (the "**Pembina Asset Acquisition**") from Obsidian Energy Ltd. ("**Obsidian**") for consideration of approximately \$291.6 million. Consideration consisted of \$203 million cash payment, the issuance of 9,139,784 common shares of InPlay to Obsidian valued at \$8.58 per share based on the closing price of InPlay shares on April 6, 2025, and the inclusion of InPlay's non-operated assets at Willesden Green Unit 2 (the "**Unit Interest**").

InPlay's capital program for first nine months of 2025 consisted of \$40.8 million of development capital. The Company drilled, completed and brought on production four (3.2 net) extended reach horizontal ("ERH") Cardium wells, drilled and completed three (3.0 net) ERH wells that came on production in October and drilled two (2.0 net) wells that are currently being completed. The Company completed a significant operated gas plant expansion and other facility projects. The Company also completed an active well servicing program during the first nine months of 2025 spending \$3.0 million of capital on optimization activities.

SELECTED ANNUAL INFORMATION

Years ended December 31

(in thousands, except per share amounts)	2024	2023	2022
Total oil and natural gas sales ⁽¹⁾	153,713	179,366	238,590
Oil and natural gas sales, net of royalties ⁽¹⁾	133,749	156,850	200,198
Profit	9,469	32,702	83,896
Profit per share, basic	0.66	2.22	5.82
Profit per share, diluted	0.60	2.16	5.52
Total assets	476,255	472,956	430,911
Total credit facilities	63,134	47,161	29,210
Total net debt ⁽²⁾	60,895	45,679	32,963

⁽¹⁾ The oil and natural gas sales exclude realized and unrealized gains (losses) on risk management derivative contracts: 2024 excludes \$2.8 million realized gain and (\$0.5 million) unrealized loss; 2023 excludes \$3.6 million realized gain and (\$1.7 million) unrealized loss; and 2022 excludes (\$6.6 million) realized loss and \$2.4 million unrealized gain.

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

ADDITIONAL INFORMATION

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

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

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

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

NON-GAAP AND OTHER FINANCIAL MEASURES

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

Non-GAAP Financial Measures and Ratios

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

Free Adjusted Funds Flow ("FAFF")

Management considers FAFF an important measure to identify the Company's ability to improve its financial condition through debt repayment and its ability to provide returns to shareholders. FAFF should not be considered as an alternative to or more meaningful than AFF as determined in accordance with GAAP as an indicator of the Company's performance. FAFF is calculated by the Company as AFF less exploration and development capital expenditures and property dispositions (acquisitions) and is a measure of the cashflow remaining after capital expenditures that can be used for additional capital activity, corporate acquisitions, repayment of debt or decommissioning expenditures or potentially return of capital to shareholders. Refer to the "Forward Looking Information and Statements" section for a calculation of forecast FAFF.

Free Adjusted Funds Flow Yield

InPlay uses "free adjusted funds flow yield" as a key performance indicator. When presented on a corporate basis, free adjusted funds flow is calculated by the Company as free adjusted funds flow divided by the market capitalization of the Company. When presented on an asset basis for acquisition purposes, free adjusted funds flow is calculated by the Company as free adjusted funds flow divided by the operating income of the Acquired Assets. Management considers FAFF yield to be an important performance indicator as it demonstrates a

Company or asset's ability to generate cash to pay down debt and provide funds for potential distributions to shareholders. Refer to the "Forward Looking Information and Statements" section for a calculation of forecast FAFF Yield.

Operating Income/ Operating Netback per boe/ Operating Income Profit Margin

InPlay uses "operating income", "operating netback per boe" and "operating income profit margin" as key performance indicators. Operating income is calculated by the Company as oil and natural gas sales less royalties, operating expenses and transportation expenses and is a measure of the profitability of operations before administrative, share-based compensation, financing and other non-cash items. Management considers operating income an important measure to evaluate its operational performance as it demonstrates its field level profitability. Operating income should not be considered as an alternative to or more meaningful than net income as determined in accordance with GAAP as an indicator of the Company's performance. 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. Operating income profit margin is calculated by the Company as operating income as a percentage of oil and natural gas sales. 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. Refer to the section entitled "Operating income and netback" within document for a calculation of these measures and a reconciliation to the nearest GAAP measure. Refer to the "Forward Looking Information and Statements" section for a calculation of forecast operating income, operating netback per boe and operating income profit margin.

Net Debt to EBITDA

Management considers Net Debt to EBITDA an important measure as it is a key metric to identify the Company's ability to fund financing expenses, net debt reductions and other obligations. EBITDA is calculated by the Company as adjusted funds flow before interest expense. When this measure is presented quarterly, EBITDA is annualized by multiplying by four. When this measure is presented on a trailing twelve-month basis, EBITDA for the twelve months preceding the net debt date is used in the calculation. This measure is consistent with the EBITDA formula prescribed under the Company's Credit Facility. Net Debt to EBITDA is calculated as Net Debt divided by EBITDA. Refer to the "Forward Looking Information and Statements" section for a calculation of forecast Net Debt to EBITDA.

Capital Management Measures

Adjusted Funds Flow

Management considers adjusted funds flow to be an important measure of InPlay's ability to generate the funds necessary to finance capital expenditures. Adjusted funds flow is a GAAP measure and is disclosed in the notes to the Company's financial statements for the three and nine months ended September 30, 2025. All references to adjusted funds flow throughout this document are calculated as funds flow adjusting for transaction and integration costs and decommissioning expenditures. Transaction and integration costs are non-recurring costs for the purposes of an acquisition, making the exclusion of these items relevant in Management's view to the reader in the evaluation of InPlay's operating performance. Decommissioning expenditures are adjusted from funds flow as they are incurred on a discretionary and irregular basis and are primarily incurred on previous operating assets. The Company also presents adjusted funds flow per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of profit per common share.

Net Debt

Net debt is a GAAP measure and is disclosed in the notes to the Company's financial statements for the three and nine months ended September 30, 2025. The Company closely monitors its capital structure with the goal

of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. The Company uses net debt (bank debt plus accounts payable and accrued liabilities less accounts receivables and accrued receivables, prepaid expenses and deposits and inventory) as an alternative measure of outstanding debt. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

Supplementary Measures

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

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

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

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

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

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

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This document 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", "targets", "should", or similar words suggesting future outcomes. In particular, this document contains forward-looking statements relating, but not limited, to:

- 2025 guidance based on the planned capital program of \$53 million including forecasts of 2025 annual average production levels, light oil and liquids weightings, adjusted funds flow, free adjusted funds flow, Net Debt/EBITDA ratio, and growth rates;
- the information contained within the "Outlook" section;
- the possible refinement of our 2025 capital program and anticipated changes resulting therefrom;
- management's assessment of the potential and uncertain continuing impacts of the Russian/Ukraine and Middle East conflicts on the Company's operations and results;
- the estimated time to payout of wells;
- production estimates;
- expectations regarding the business environment, industry conditions and future commodity prices;
- InPlay's business strategy, goals and management focus;

- sources of funds for the Company's operations, capital expenditures and decommissioning obligations;
- future liquidity and the Company's access to sufficient debt and equity capital;
- the resource potential of InPlay's asset base and future prospects for development and growth;
- future costs, expenses and royalty rates;
- the volume and product mix of InPlay's oil and gas production;
- future exchange rate between the \$US and \$Cdn
- expectations regarding InPlay's tax horizon;
- capital management strategies;
- the anticipated continuation of the Company's monthly dividend program and the amounts of dividends;
- the timing and impact of new accounting policies and standards;
- treatment under governmental and other regulatory regimes and tax, environmental and other laws;
- the potential scope and duration of tariffs, export taxes, export restrictions or other trade actions;
- magnitude and duration of potential new or increased tariffs may be imposed on goods imported from Canada into the United States, which could adversely impact InPlay's revenues;
- the potential for new and increased U.S. tariffs and protectionist trade measures on Canadian oil and gas imports;
- changes in political and economic conditions, including risks associated with tariffs, export taxes, export restrictions or other trade actions;
- impacts of any tariffs imposed on Canadian exports into the United States by the Trump administration and any retaliatory steps taken by the Canadian federal government;
- with a global footprint and supply chain, InPlay's results and operations could be adversely affected by economic or geopolitical developments, including protectionist trade policies such as tariffs, or other events;
- conditions in international markets, including social and political conditions, civil unrest, terrorist activity, governmental changes, restrictions on the ability to transfer capital across borders, tariffs and other protectionist measures; and
- the risk that the new U.S. administration imposes additional tariffs on Canadian goods, including crude oil and natural gas, and that such tariffs (and/or the Canadian government's response to such tariffs) adversely affect the demand and/or market price for InPlay's products and/or otherwise adversely affect InPlay.

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 labour 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, world events, market conditions, drilling success and potential timing delays.

These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond InPlay's control. Such risks and uncertainties include, without limitation: the impact of general economic conditions; volatility in market prices for crude oil and natural gas; the risk that (i) the U.S. and/or Canadian governments increases the rate or scope of new tariffs effected on March 4, 2025, and subsequently paused on March 6, 2025, if they come into effect in the future, or imposes new tariffs on the import of goods from one country to the other, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed by the U.S. on other countries and responses thereto could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and InPlay; the ongoing Russia/Ukraine and Middle East conflicts; 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 document 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 document 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 and risks that could affect InPlay's operations and financial results are included in the Company's public disclosure documents on file with Canadian securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.ca) or at InPlay's website (www.inplayoil.com).

The internal projections, expectations, or beliefs underlying our Board approved 2025 capital budget and associated guidance are subject to change in light of, among other factors, changes to U.S. economic, regulatory and/or trade policies (including tariffs), the impact of world events including the Russia/Ukraine conflict and war in the Middle East, ongoing results, prevailing economic circumstances, volatile commodity prices, and changes in industry conditions and regulations. InPlay's 2025 financial outlook and revised guidance provides shareholders with relevant information on management's expectations for results of operations, excluding any potential acquisitions or dispositions, for such time periods based upon the key assumptions outlined herein. Readers are cautioned that events or circumstances could cause capital plans and associated results to differ materially from those predicted and InPlay's revised guidance for 2025 may not be appropriate for other purposes. Accordingly, undue reliance should not be placed on same.

Forward-looking statements or information are based on a number of material factors, expectations or assumptions of InPlay which have been used to develop such statements and information, but which may prove to be incorrect. Although InPlay believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because InPlay can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the current U.S. economic, regulatory and/or trade policies; the impact of increasing competition; the general stability of the economic and political environment in which InPlay operates; the timely receipt of any required regulatory approvals; the ability of InPlay to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects in which InPlay has an

interest in to operate the field in a safe, efficient and effective manner; the ability of InPlay to obtain debt financing on acceptable terms; the anticipated tax treatment of the monthly base dividend; that other than the tariffs that came into effect on March 4, 2025 (some of which were subsequently paused on March 6, 2025), neither the U.S. nor Canada (i) increases the rate or scope of such tariffs (if they come into effect in the future), or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; the potential scope and duration of tariffs, export taxes, export restrictions or other trade actions; magnitude and duration of potential new or increased tariffs may be imposed on goods imported from Canada into the United States, which could adversely impact InPlay's revenues; the potential for new and increased U.S. tariffs and protectionist trade measures on Canadian oil and gas imports; changes in political and economic conditions, including risks associated with tariffs, export taxes, export restrictions or other trade actions; impacts of any tariffs imposed on Canadian exports into the United States by the Trump administration and any retaliatory steps taken by the Canadian federal government; that InPlay's results and operations could be adversely affected by economic or geopolitical developments, including protectionist trade policies such as tariffs, or other events; conditions in international markets, including social and political conditions, civil unrest, terrorist activity, governmental changes, restrictions on the ability to transfer capital across borders, tariffs and other protectionist measures; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and cost of pipeline, storage and facility construction and the ability of InPlay to secure adequate product transportation; future commodity prices; that various conditions to a shareholder return strategy can be satisfied; the ongoing impact of the Russia/Ukraine conflict and war in the Middle East; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which InPlay operates; and the ability of InPlay to successfully market its oil and natural gas products.

Without limitation of the foregoing, readers are cautioned that the Company's future dividend payments to shareholders of the Company, if any, and the level thereof will be subject to the discretion of the Board of Directors of InPlay. The Company's dividend policy and funds available for the payment of dividends, if any, from time to time, is dependent upon, among other things, levels of FAFF, leverage ratios, financial requirements for the Company's operations and execution of its growth strategy, fluctuations in commodity prices and working capital, the timing and amount of capital expenditures, credit facility availability and limitations on distributions existing thereunder, and other factors beyond the Company's control. Further, the ability of the Company to pay dividends will be subject to applicable laws, including satisfaction of solvency tests under the Business Corporations Act (Alberta), and satisfaction of certain applicable contractual restrictions contained in the agreements governing the Company's outstanding indebtedness. Further, the actual amount, the declaration date, the record date and the payment date of any dividend are subject to the discretion of the InPlay Board of Directors. There can be no assurance that InPlay will pay dividends in the future.

The forward-looking information and statements included herein are not guarantees of future performance and should not be unduly relied upon. Such information and statements, including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in industry regulations and legislation (including, but not limited to, tax laws, royalties, and environmental regulations); risks related to an international trade war, including the risk that the U.S. government imposes additional tariffs on Canadian goods, including crude oil and natural gas, and that such tariffs (and/or the Canadian government's response to such tariffs) adversely affect the demand and/or market price for InPlay's products and/or otherwise adversely affects InPlay; the continuing impact of the Russia/Ukraine conflict and war in the Middle East; potential changes to U.S. economic, regulatory and/or trade policies as a result of a change in government; inflation and the risk of a global recession; changes in our planned 2025 capital program; changes in our approach to shareholder returns; changes in commodity prices and other assumptions outlined herein; the risk that dividend payments may be reduced, suspended or cancelled; the potential for variation in the quality of the reservoirs in which InPlay operates; changes in the

demand for or supply of InPlay's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans or strategies of InPlay or by third party operators of InPlay's properties; changes in InPlay's credit structure, increased debt levels or debt service requirements; inaccurate estimation of InPlay's light crude oil and natural gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in InPlay's continuous disclosure documents filed on SEDAR+ including InPlay's Annual Information Form dated March 31, 2025 and the annual management's discussion & analysis for the year ended December 31, 2024.

This document contains future-oriented financial information and financial outlook information (collectively, "FOFI") about InPlay's financial and leverage targets and objectives, potential dividends, and beliefs underlying our Board approved 2025 capital budget and associated guidance, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. The actual results of operations of InPlay and the resulting financial results will likely vary from the amounts set forth in this document and such variation may be material. InPlay and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's reasonable estimates and judgments. However, because this information is subjective and subject to numerous risks, it should not be relied on as necessarily indicative of future results. Except as required by applicable securities laws, InPlay undertakes no obligation to update such FOFI. FOFI contained in this document was made as of the date of this document and was provided for the purpose of providing further information about InPlay's anticipated future business operations and strategy. Readers are cautioned that the FOFI contained in this document should not be used for purposes other than for which it is disclosed herein.

The forward-looking information and statements contained in this document speak only as of the date hereof and InPlay does not assume any obligation to publicly update or revise any of the included forward-looking statements or information, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Risk Factors to FLI

Risk factors that could materially impact successful execution and actual results of the Company's 2025 capital program and associated guidance and estimates include:

- risks related to an international trade war, including the risk that the U.S. government imposes additional tariffs on Canadian goods, including crude oil and natural gas, and that such tariffs (and/or the Canadian government's response to such tariffs) adversely affect the demand and/or market price for the Company's products and/or otherwise adversely affect the Company;
- volatility of petroleum and natural gas prices and inherent difficulty in the accuracy of predictions related thereto;
- the extent of any unfavourable impacts of wildfires in the province of Alberta.
- changes in Federal and Provincial regulations;
- the Company's ability to secure financing for the Board approved 2025 capital program and longer-term capital plans sourced from AFF, bank or other debt instruments, asset sales, equity issuance, infrastructure financing or some combination thereof; and
- those additional risk factors set forth in the Company's MD&A and most recent Annual Information Form filed on SEDAR+.

Key Budget and Underlying Material Assumptions to FLI

The key budget and underlying material assumptions used by the Company in the development of its 2025 guidance are as follows:

Management's Discussion and Analysis

		Actuals FY 2024	Updated Guidance FY 2025	Previous Guidance FY 2025 ⁽¹⁾
WTI	US\$/bbl	\$75.72	\$65.00	\$63.10
NGL Price	\$/boe	\$32.99	\$34.75	\$35.00
AECO	\$/GJ	\$1.39	\$1.60	\$2.30
Foreign Exchange Rate	CDN\$/US\$	0.73	0.71	0.70
MSW Differential	US\$/bbl	\$4.51	\$3.25	\$3.70
Production	Boe/d	8,712	16,900 – 17,100	16,000 – 16,800
Revenue	\$/boe	48.21	45.25 – 50.25	46.75 – 51.75
Royalties	\$/boe	6.26	6.00 – 7.10	5.25 – 6.75
Operating Expenses	\$/boe	15.12	16.00 – 17.00	15.00 – 17.00
Transportation	\$/boe	0.97	0.80 – 1.00	0.80 – 1.05
Interest	\$/boe	2.19	2.80 – 3.40	2.80 – 3.50
General and Administrative	\$/boe	3.06	2.15 – 2.60	2.00 – 2.75
Hedging loss (gain)	\$/boe	(0.86)	(0.00) – (1.00)	(0.00) – (1.00)
Decommissioning Expenditures	\$ millions	\$3.4	\$4.0 – \$4.5	\$5.5 – \$6.5
Adjusted Funds Flow	\$ millions	\$68.5	\$119 – \$122	\$124 – \$133
Dividends	\$ millions	\$16	\$27	\$26 – \$27

		Actuals FY 2024	Updated Guidance FY 2025	Previous Guidance FY 2025 ⁽¹⁾
Adjusted Funds Flow	\$ millions	\$68.5	\$119 – \$122	\$124 – \$133
Capital Expenditures	\$ millions	\$63	\$53	\$53 – \$60
Free Adjusted Funds Flow	\$ millions	\$5.5	\$66 – \$69	\$68 – \$76
Shares outstanding, end of year	# millions	15.0	28.0	28.0
Assumed share price	\$/share	\$10.38	12.50	\$6.60
Market capitalization	\$ millions	\$156	\$350	\$185
FAFF Yield	%	4%	19% – 21%	35% – 40%

		Actuals FY 2024	Updated Guidance FY 2025	Previous Guidance FY 2025 ⁽¹⁾
Revenue	\$/boe	48.21	45.25 – 50.25	46.75 – 51.75
Royalties	\$/boe	6.26	6.00 – 7.10	5.25 – 6.75
Operating Expenses	\$/boe	15.12	16.00 – 17.00	15.00 – 17.00
Transportation	\$/boe	0.97	0.80 – 1.00	0.80 – 1.05
Operating Netback	\$/boe	25.86	21.75 – 26.75	23.75 – 28.75
Operating Income Profit Margin		54%	51%	53%

		Actuals FY 2024	Updated Guidance FY 2025	Previous Guidance FY 2025 ⁽¹⁾
Adjusted Funds Flow	\$ millions	\$68.5	\$143 – \$150 ⁽²⁾	\$146 – \$164 ⁽⁴⁾
Interest	\$/boe	2.19	3.00 – 3.50 ⁽²⁾	3.05 – 3.65 ⁽⁴⁾
EBITDA	\$ millions	\$76	\$166 – \$173 ⁽²⁾	\$168 – \$186 ⁽⁴⁾
Net Debt	\$ millions	\$61	\$213 – \$216	\$213 – \$221
Net Debt/EBITDA		0.8	1.2 – 1.3	1.1 – 1.3

⁽¹⁾ As previously released May 8, 2025.

⁽²⁾ InPlay's EBITDA for this column is based on Q4 2025 annualized figures.

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

PRODUCTION BREAKDOWN BY PRODUCT TYPE

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

	Light and Medium Crude oil (bbls/d)	NGLs (boe/d)	Conventional Natural gas (Mcf/d)	Total (boe/d)
Q1 2024 Average Production	3,452	1,487	22,000	8,605
Q2 2024 Average Production	3,671	1,438	21,291	8,657
Q3 2024 Average Production	3,279	1,418	21,052	8,206
2024 Average Production	3,523	1,499	22,139	8,712
Q1 2025 Average Production	3,429	1,572	24,452	9,076
Q2 2025 Average Production	10,328	2,401	46,029	20,401
Q3 2025 Average Production	9,122	2,334	45,081	18,970
2025 Previous Annual Guidance	7,890	2,070	38,640	16,400 ⁽¹⁾
2025 Updated Annual Guidance	8,170	2,145	40,110	17,000 ⁽²⁾

Notes:

1. This reflects the mid-point of the Company's previous 2025 production guidance range of 16,000 to 16,800 boe/d.
2. This reflects the mid-point of the Company's previous 2025 production guidance range of 16,900 to 17,100 boe/d.
3. With respect to forward-looking production guidance, product type breakdown is based upon management's expectations based on reasonable assumptions but are subject to variability based on actual well results.

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

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