Management's Discussion and Analysis

For the three and six months ended June 30, 2024

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2024 AND JUNE 30, 2023

The following management's discussion and analysis ("**MD&A**") is dated August 14, 2024 and should be read in conjunction with the unaudited financial statements of InPlay Oil Corp. ("**InPlay**" or the "**Company**") for the three and six months ended June 30, 2024 and June 30, 2023 and the audited annual financial statements for the years ended December 31, 2023 and December 31, 2022. 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.

REVIEW OF FINANCIAL RESULTS

Production

Average production volumes for the three and six months ended June 30, 2024 and June 30, 2023 were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Crude oil (bbls/d)	**3,671**	3,658	**3,561**	3,722
NGLs (boe/d)	**1,438**	1,187	**1,462**	1,322
Natural gas (Mcf/d)	**21,291**	21,772	**21,645**	22,208
Total (boe/d)(1)(2)(3)	**8,657**	8,474	**8,631**	8,746
Crude oil and NGLs (%)	**59%**	57%	**58%**	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 ("Nl 51-101").

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

Production for the three and six months ended June 30, 2024 was 2% higher and flat respectively compared to the three and six months ended June 30, 2023. The light oil and liquids weighting of 59% for the three months ended June 30, 2024 improved compared to the three months ended June 30, 2023. The light oil and liquids weighting of 58% for the six months ended June 30, 2024 remained flat compared to the six months ended June 30, 2023.

InPlay's capital program for first half of 2024 consisted of $31.7 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, three (3.0 net) ERH wells in Pembina and three (0.65 net) non-operated Willesden Green ERH wells during the first quarter of 2024, with the majority of these new wells coming on production late in March. The Company also drilled one (1.0 net) Belly River well during the second quarter of 2024 which is expected to be on production in the third quarter and started drilling one (1.0 net) Willesden Green Glauconite well in June. Approximately $2.9 million was spent on the optimization of wells during the first half of 2024 where pumps in older, low-rate horizontal wells have been lowered.

(thousands of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Crude oil	**34,373**	30,944	**62,495**	64,091
NGLs	**4,325**	3,645	**8,883**	8,880
Natural gas	**2,762**	5,173	**8,079**	12,092
Total crude oil and natural gas sales	**41,460**	39,762	**79,457**	85,063

Prices

	Three Months Ended June 30		Six Months Ended June 30	
Average Realized Price(1)	**2024**	2023	**2024**	2023
Crude oil ($/bbl)	**102.89**	92.97	**96.42**	95.12
NGLs ($/boe)	**33.06**	33.73	**33.38**	37.12
Natural gas ($/Mcf)	**1.43**	2.61	**2.05**	3.01
Total ($/boe)	**52.63**	51.56	**50.58**	53.74
WTI ($USD/bbl)	**80.57**	73.78	**78.76**	74.96
AECO ($/GJ)	**1.12**	2.32	**1.74**	2.69

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

In the second quarter of 2024, WTI oil prices increased 9% averaging $80.57 US per bbl compared to $73.78 US per bbl in the second quarter of 2023. In the first half of 2024, WTI oil prices increased 5% averaging $78.76 US per bbl compared to $74.96 US per bbl in the first half of 2023.

Differentials between WTI oil prices and prices received in Alberta increased in the three and six months ended June 30, 2024 compared to the same periods in 2023. These differentials can be volatile due to factors including refining demand and pipeline capacity. InPlay sells oil at monthly average Edmonton Par prices less quality differentials, transportation and marketing fees. Light, sweet oil differentials between Cushing, Oklahoma and Edmonton, Alberta are affected by pipeline apportionment, refinery turnarounds, rail capacity and market supply/demand conditions. Monthly index differentials averaged $3.63 US per barrel discount for the second quarter of 2024 compared to $3.08 US per barrel discount for the second quarter of 2023, improving significantly from the differential of $8.65 US per barrel in the first quarter of 2024. Monthly index differentials averaged $6.14 US per barrel discount for the first half of 2024 compared to $2.98 US per barrel discount for the same period in 2023.

Realized oil prices are adjusted for the Canada/US exchange rate which decreased averaging 0.73 for the second quarter of 2024 from 0.74 during the second quarter of 2023. The Canada/US exchange rate remained flat over the first half of 2024 at 0.74 compared to 0.74 over the first half of 2023.

Due to the items noted above, realized oil prices for the three and six months ended June 30, 2024 increased compared to the three and six months ended June 30, 2023. The Company's average net realized price for crude oil was $102.89 per bbl for the second quarter of 2024, 11% higher than the second quarter 2023 realized price of $92.97 per bbl. The Company's average net realized price for crude oil was $96.42 per bbl for the first half of 2024, 1% higher than the first half of 2023 realized price of $95.12 per bbl.

In the second quarter of 2024, natural gas AECO daily index prices decreased 52% averaging $1.12 per GJ compared to $2.32 per GJ in the second quarter of 2023. In the first half of 2024, natural gas AECO daily index prices decreased 35% averaging $1.74 per GJ compared to $2.69 per GJ in the first half of 2023.

The Company's average realized natural gas sales price was $1.43 per Mcf for the second quarter of 2024, 45% lower than the second quarter of 2023 realized price of $2.61 per Mcf as a result of depressed natural gas prices. The Company's average realized natural gas sales price was $2.05 per Mcf for the six months ended June 30, 2024, 32% lower than the first half of 2023 realized price of $3.01 per Mcf.

Realized NGL pricing remained relatively unchanged for the three months ended June 30, 2024 compared to the same period in 2023. The Company's average realized NGL price was $33.06 per boe for the second quarter compared $33.73 per boe in the second quarter of 2023. The Company's average realized NGL sales price was $33.38 per boe for the first half of 2024, 10% lower than the first half of 2023 realized price of $37.12 per boe, also as a result of lower realized butane prices.

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 June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Total royalties ($'000s)	**5,063**	3,137	**9,590**	10,791
Total royalties (% of sales)	**12.2%**	8.0%	**12.1%**	12.7%
Total royalties ($/boe)	**6.43**	4.07	**6.10**	6.82

Royalties during the second quarter of 2024 were higher on an absolute and per boe basis as a result of the royalty credits realized in the three months ended June 30, 2023 related to Crown Gas Cost Allowance credit adjustment for 2022 and prior period Crown royalty gas incentive period calculation amendments.

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 June 30, 2024 the Company had the following commodity-based derivative contracts outstanding:

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

Currency denomination	Volume (mcf/day)	Average swap price	Term
Canadian dollar	1,900	2.00/mcf	April 1, 2024 – October 31, 2024

Type of contract: costless collar[(1)] (natural gas pricing AECO):

Currency denomination	Volume (mcf/day)	Bought put price	Sold call price	Term
Canadian dollar	1,900	2.06/mcf	2.48/mcf	Feb. 1, 2024 – Dec. 31, 2024
Canadian dollar	1,900	2.11/mcf	3.06/mcf	Feb. 1, 2024 – March 31, 2025
Canadian dollar	1,900	2.85/mcf	3.85/mcf	Nov. 1, 2024 – March 31, 2025

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

Type of contract: costless collar[(2)] (crude oil pricing WTI):

Currency denomination	Volume (bbl/day)	Bought put price	Sold call price	Term
US dollar	1,000	72.00/bbl	80.25/bbl	April 1, 2024 – June 30, 2024

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

Type of contract: three-way collar[(3)] (crude oil pricing WTI):

Currency denomination	Volume (bbl/day)	Sold put price	Bought put price	Sold call price	Term
US dollar	1,000	64.00/bbl	74.00/bbl	82.48/bbl	July 1, 2024 – Dec. 31, 2024

(3) The WTI three-way collars are a combination high priced sold call, low priced sold put and a mid-priced bought put. The high sold call price is the maximum price the Company will receive for the contract volumes. The mid bought put price is the minimum price InPlay will receive, unless the market price falls below the low sold put strike price, in which case InPlay receives market price plus the difference between the mid bought put price minus the low sold put price

The statements of profit and comprehensive income for the three and six months ended June 30, 2024 reflected the following gains (losses) related to derivative contracts that were outstanding during 2024 and the comparative periods for 2023.

(thousands of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Realized gain	**195**	1,598	**422**	1,598
Unrealized gain (loss)	**1,130**	(1,439)	**337**	440
Total gain (loss) on derivative contracts	**1,325**	159	**759**	2,038

Subsequent to June 30, 2024, InPlay entered into an electricity hedge fixing InPlay's electricity cost for one megawatt ("MW") for a four year term at $62.17 per megawatt hour ("MWh").

Operating expenses

	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Total operating expenses ($'000s)	**11,672**	11,731	**23,701**	23,666
Total operating expenses ($/boe)	**14.81**	15.21	**15.09**	14.95

Operating costs include expenses incurred to operate wells, gather and treat production volumes as well as costs to perform well and facility repairs and maintenance. For the three months ended June 30, 2024, operating expenses per boe decreased to $14.81 per boe compared to $15.21 per boe for the same period in 2023. For the six months ended June 30, 2024, operating expenses per boe increased slightly to $15.09 per boe compared to $14.95 per boe for the same period in 2023.

Transportation expenses

	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Total transportation expenses ($'000s)	**773**	749	**1,630**	1,492
Total transportation expenses ($/boe)	**0.98**	0.97	**1.04**	0.94

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 June 30, 2024, transportation expenses were $0.98 per boe and were flat in comparison to $0.97 per boe for the quarter ended June 30, 2023. For the six months ended June 30, 2024, transportation expenses were $1.04 per boe and were slightly higher in comparison to $0.94 per boe for the six months ended June 30, 2023.

Operating Income and Netback

(thousands of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Revenue(1)	**41,460**	39,762	**79,457**	85,063
Royalties	**(5,063)**	(3,137)	**(9,590)**	(10,791)
Operating expenses	**(11,672)**	(11,731)	**(23,701)**	(23,666)
Transportation expenses	**(773)**	(749)	**(1,630)**	(1,492)
Operating income (2)	**23,952**	24,145	**44,536**	49,114
Sales volume (Mboe)	**787.8**	771.1	**1,570.9**	1,582.9
Per boe				
Revenue(1)	**52.63**	51.56	**50.58**	53.74
Royalties	**(6.43)**	(4.07)	**(6.10)**	(6.82)
Operating expenses	**(14.81)**	(15.21)	**(15.09)**	(14.95)
Transportation expenses	**(0.98)**	(0.97)	**(1.04)**	(0.94)
Operating netback per boe (2)	**30.41**	31.31	**28.35**	31.03
Operating income profit margin (2)	**58%**	61%	**56%**	58%

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

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

Operating income and operating netback per boe remained relatively unchanged for the three months ended June 30, 2024 and decreased slightly for the six months ended June 30, 2024 compared to the three and six months ended June 30, 2023 reflecting the decreases to realized commodity prices over these periods.

General and administrative expenses

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

(thousands of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Gross G&A expenditures	**2,885**	3,429	**5,932**	6,630
Capitalized and recoveries	**(641)**	(630)	**(1,256)**	(1,330)
General and administrative expenses	**2,244**	2,799	**4,676**	5,300
G&A expenses ($/boe)	**2.85**	3.63	**2.98**	3.35
% Capitalized and recoveries	**22%**	18%	**21%**	20%

For the quarter ended June 30, 2024, G&A expenses were $2.2 million ($2.85 per boe) compared to $2.8 million ($3.63 per boe) for the same period in 2023. For the six months ended June 30, 2024, G&A expenses were $4.7 million ($2.98 per boe) compared to $5.3 million ($3.35 per boe) for the same period in 2023. Lower G&A expenses on a per boe and total basis in the second quarter and first half of 2024 in comparison to the same periods in 2023 are a result of less external services required during these periods in 2024.

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 and comprehensive income.

(thousands of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Share-based compensation	**878**	1,257	**2,361**	2,258
Capitalized portion	**(206)**	(267)	**(539)**	(505)
Share-based compensation expense	**672**	990	**1,822**	1,753

For the quarter ended June 30, 2024, share-based compensation expense was $0.7 million compared to $1.0 million for the same period in 2023. For the six months ended June 30, 2024, share-based compensation expense was $1.8 million compared to $1.8 million for the same period in 2023.

During the six months ended June 30, 2024, 62,200 options were exercised.

At June 30, 2024, the maximum number of stock options available for grant was 9,011,935 and 2,636,680 stock options were outstanding.

In 2022, the Company implemented a Restricted and Performance Award Incentive Plan 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 evenly 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. 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 is eligible, at its discretion, 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 movements of outstanding RAs and PAs during the six months ended June 30, 2024 and the year ended December 31, 2023 were as follows:

	Number of RAs	Number of PAs
Outstanding at December 31, 2022	735,749	428,710
Granted during the period	772,095	489,700
Dividend make-whole adjustment	82,181	50,066
Vested during the period	(245,791)	(150,882)
Forfeited during the period	(55,897)	(33,438)
Outstanding at December 31, 2023	1,288,337	784,156
Granted during the period	29,000	-
Dividend make-whole adjustment	48,144	28,841
Vested during the period	(4,466)	-
Payout multiplier adjustment	-	179,957
Outstanding at June 30, 2024	**1,361,015**	**992,954**

Depletion and depreciation

	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Depletion and depreciation ($'000s)	**11,817**	11,270	**23,485**	23,017
Depletion and depreciation ($/boe)	**15.00**	14.62	**14.95**	14.54

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 $11.8 million ($15.00 per boe) for the quarter ended June 30, 2024 compared to $11.3 million ($14.62 per boe) for the same period in 2023. Depletion and depreciation was $23.5 million ($14.95 per boe) for the six months ended June 30, 2024 compared to $23.0 million ($14.54 per boe) for the same period in 2023.

Impairment

At June 30, 2024 there were no indicators of impairment. As of December 31, 2023, all previously recorded impairments had been fully reversed.

Indicators of impairment relating to Property, plant and equipment were considered to exist as at December 31, 2023 as the Company's net assets were greater than its market capitalization. Impairment tests were 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, 2023. 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, 2023.

The following table shows the benchmark commodity prices used in the impairment calculation of Property, plant and equipment at December 31, 2023 of which are based on an average of independent reserve evaluator pricing estimates.

	Light, Sweet Crude Edmonton ($Cdn/bbl)	AECO Gas Price ($Cdn/MMBtu)
Year	December 31, 2023	December 31, 2023
2024	92.91	2.20
2025	95.04	3.37
2026	96.07	4.05
2027	97.99	4.13
2028	99.95	4.21
2029	101.94	4.30
2030	103.98	4.38
2031	106.06	4.47
2032	108.18	4.56
2033	110.35	4.65

At June 30, 2024 there were no indicators of impairment relating to the Company's Exploration and evaluation assets.

Finance expenses

(thousands of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Interest expense (Credit Facility and other)	**1,450**	1,030	**2,923**	2,141
Interest expense (Lease liabilities)	**325**	30	**655**	48
Accretion on decommissioning obligations	**740**	716	**1,459**	1,446
Finance expense	**2,515**	1,776	**5,037**	3,635

Finance expenses were $2.5 million for the second quarter of 2024, compared to $1.8 million in the second quarter of 2023. Finance expenses were $5.0 million for the six months ended June 30, 2024, compared to $3.6 million during the same period in 2023. Finance expenses increased for the three and six months ended June 30, 2024 as a result bank debt outstanding and increases to interest associated with new leases entered into in the fourth quarter of 2023.

Income taxes

The Company has recognized a deferred tax asset of $16.2 million at June 30, 2024. The Company recognized deferred income tax expense of $1.6 million during the three months ended June 30, 2024 and deferred income tax expense of $2.2 million during the six months ended June 30, 2024.

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 credited by $nil during the six months ended June 30, 2024 (June 30, 2023 - $0.5 million) with a corresponding impact to the deferred income tax asset. At June 30, 2024, the Company had $2.5 million of unrecognized deferred tax asset (December 31, 2023 - $2.5 million).

InPlay is not currently cash taxable and had the following estimated Canadian federal income tax pool balances at June 30, 2024.

(thousands of dollars)	
Non-capital loss carryforward balances	112,665
Share issue costs	438
Canadian Exploration Expenses (CEE)	53,814
Canadian Development Expenses (CDE)	95,109
Canadian Oil and Gas Property Expenses (COGPE)	96,846
Undepreciated Capital Cost (UCC)	46,817
Total	405,689

ADJUSTED FUNDS FLOW

(thousands of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Funds flow	**19,400**	21,543	**35,404**	41,936
Decommissioning expenditures	**745**	225	**1,267**	1,125
Adjusted funds flow(1)	**20,145**	21,768	**36,671**	43,061

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

Adjusted funds flow for the three and six months ended June 30, 2024 was $20.1 million and $36.7 million respectively compared to $21.8 million and $43.1 million for the three and six months ended June 30, 2023. These decrease for the six month period year over year is reflective of the decreases in benchmark prices realized during the respective periods.

CAPITAL EXPENDITURES

Capital expenditures for the three months ended June 30, 2024 were $5.4 million of development capital. Capital expenditures for the six months ended June 30, 2024 were $30.9 million of development capital. The breakdown of capital expenditures is shown below:

(thousands of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2024	2023	**2024**	2023
Drilling & completions	**2,036**	10,388	**22,950**	32,394
Facilities and equipping costs, net of dispositions	**1,225**	1,734	**4,038**	8,519
Well optimization	**1,605**	155	**2,904**	375
Total development capital	**4,866**	12,277	**29,892**	41,288
Office and Capitalized G&A	**523**	481	**1,001**	1,038
Capital expenditures – PP&E	**5,389**	12,758	**30,893**	42,326
Land and lease	**27**	16	**54**	48
Exploratory drilling	**740**	-	**740**	-
Capital expenditures – PP&E and E&E	**6,156**	12,774	**31,687**	42,374
Property acquisitions (dispositions)	**-**	-	**(25)**	327
Total capital expenditures	**6,156**	12,774	**31,662**	42,701

InPlay's capital program for first half of 2024 consisted of $31.7 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, three (3.0 net) ERH wells in Pembina and three (0.65 net) non-operated Willesden Green ERH wells during the first quarter of 2024, with the majority of these new wells coming on production late in March. The Company also drilled one (1.0 net) Belly River well during the second quarter of 2024 which is expected to be on production in the third quarter and started drilling one (1.0 net) Willesden Green Glauconite well in June. Approximately $2.9 million was spent on the optimization of wells during the first half of 2024 where pumps in older, low-rate horizontal wells have been lowered.

Drilling statistics are shown below:

	Three months ended June 30				Six months ended June 30			
	2024		2023		**2024**		2023	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**1**	**1.0**	2	1.9	**9**	**6.6**	11	8.3
Natural gas	**-**	**-**	-	-	**-**	**-**	-	-
Dry	**-**	**-**	-	-	**-**	**-**	-	-
Total	**1**	**1.0**	2	1.9	**9**	**6.6**	11	8.3
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 August 14, 2024, there were 90,119,356 common shares outstanding, which includes 949,736 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 2,636,680 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 1,361,015 RAs and 992,954 PAs outstanding.

The Company periodically provide 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 six months ended June 30, 2024, the independent trustee purchased 255,075 common shares for a total cost of $0.5 million and as at June 30, 2024, the independent trustee held 949,736 common shares in trust.

On November 10, 2023, the Company announced that the Toronto Stock Exchange had accepted the notice of the Company's intention to renew its Normal Course Issuer Bid ("NCIB"). Pursuant to the NCIB, the Company is permitted to purchase up to 6,637,064 common shares representing approximately 10% of its public float as at October 31, 2023 over a twelve month period commencing November 14, 2023. During the six months ended June 30, 2024, the Company did not purchase any common shares for cancellation.

The Company's Board of Directors approved the implementation of a monthly base cash dividend of $0.015 per share commencing in November 2022 which resulted in the payment of $8.2 million in dividends during the six months ended June 30, 2024 (June 30, 2023 - $8.0 million).

Subsequent to June 30, 2024, the Board of Directors approved and declared monthly cash dividends of $0.015 per share, designated as eligible dividends, payable to shareholders of record on July 15, 2024 and August 15, 2024. The dividend payment date for these dividends is July 31, 2024 and August 30, 2024.

RELATED PARTY TRANSACTIONS

InPlay had no related party transactions that were entered into under the normal course of business for the three and six months ended June 30, 2024 and June 30, 2023.

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.

On June 24, 2024, the Company renewed its senior credit facility (the "Credit Facility"). The Credit Facility has a borrowing base of $110 million and consists of a $95 million revolving line of credit and a $15 million operating line of credit. The Credit Facility has a term out date of June 30, 2025, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable one year later on June 30, 2026. The Credit Facility is secured by a floating charge debenture of $150 million and a general security agreement on the assets of the Company. At June 30, 2024, the Company had drawn $54.6 million on the Credit Facility. There are standard reporting covenants under the Credit Facility and no financial covenants. The Company was in compliance with these standard reporting covenants as at June 30, 2024.

Under the 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 Credit Facility is scheduled for semi-annual renewal on or before November 30, 2024 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 Credit Facility will not be adjusted at the next semi-annual review. In the event that the lenders reduce the borrowing base under the 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 Credit Facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

In addition to the amount drawn on the Credit Facility at June 30, 2024 the Company had a current assets (excluding derivative contracts) less accounts payable and accrued liabilities surplus of $3.8 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 June 30, 2024, these obligations include:

- **Loan agreements** – The Credit Facility has a term out date of June 30, 2025 and, if not extended, any outstanding balances would have become repayable one year later on June 30, 2026. 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 June 30, 2024 were not recognized as a liability at June 30, 2024.

As at June 30, 2024 the Company had the following minimum contractual obligations:

Contractual obligations (in thousands of dollars)	2024	2025	2026	2027	2028+
Accounts payable	24,311	-	-	-	-
Bank debt - principal[1]	-	-	54,618	-	-
Bank debt - interest[2]	2,714	5,427	2,714	-	-
Lease liability	165	723	812	732	1,554
Firm service	597	1,182	636	-	-
Gas processing	1,540	3,417	3,486	3,555	3,636
Total	29,327	10,749	62,266	4,287	5,190

(1) Assumes the Credit Facility is not renewed on June 30, 2025, whereby outstanding balances become due on June 30, 2026.

(2) Assumes interest is incurred on bank debt outstanding on the Credit Facility at June 30, 2024 at the Company's effective interest rate during the current quarter and the principal of the Credit Facility is repaid June 30, 2026.

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 six months ended June 30, 2024. 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, 2023 and December 31, 2022.

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

Decommissioning obligations

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

Income taxes

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

CHANGES IN ACCOUNTING POLICIES

There were no new or amended accounting standards or interpretations adopted in the six months ended June 30, 2024, except as noted below.

The following accounting policy was adopted during the six months ended June 30, 2024.

IAS 1 "Presentation of Financial Statements"

The Company has adopted, as of January 1, 2024, the amendments to IAS 12 Income Taxes as issued by the IASB in May 2021. These amendments require entities to recognize deferred tax on transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences. The impact of this amendment did not have a material impact on the Company's financial statements.

The Company has reviewed the following reporting and accounting standard that has been issued, but is 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 FVOCI 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 April 1, 2024 and ended on June 30, 2024 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 neighboring nations, the war in the Middle East, and the actions, including sanctions, taken by NATO nations against this aggression, 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 declined sharply in the latter part of 2015 and continue to remain volatile as oil is a geopolitical commodity, affected by concerns about global economic markets, continued instability in oil producing countries and increases in production from US tight oil plays. 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.

OUTLOOK

The Company has brought one well on production since first quarter drilling and has adjusted plans so that the majority of the remaining wells in the year will come on production in late October to early November. These new wells will come online into higher anticipated winter natural gas pricing where forward future gas prices are forecasted to be approximately three times higher than current prices. This timing will lead to strong production and FAFF in the fourth quarter with the limited capital program.

We recently finished drilling operations on a two (2.0 net) horizontal Cardium well pad in Willesden Green where completions are expected to start in the coming days. InPlay plans to drill four (4.0 net) additional wells throughout the remainder of the year, including a minimum of three (3.0 net) ERH wells in Pembina Cardium Unit 7. This area delivers strong oil production rates augmented with high gas rates and lower production declines compared to other Cardium wells in our inventory, all of which result in this area generating some of the strongest returns within the Company. We are excited to resume development in this highly prolific area (after entering into long term gas handling agreement in the first quarter) and expect to pursue continuous development over the next few years.

InPlay continues to be disciplined with capital allocation and anticipates the Company's 2024 budgeted exploration and development expenditures remain unchanged at $64 - $67 million, with the developed well count dropping from 14 – 15 to 12.6. The Company is adjusting its annual production guidance by 4% to 8,700 – 9,000 boe/d (58% – 60% light crude oil and NGLs), mainly reflecting the foregone production from the Glauconite well, downtime and shut-ins, and the planned rescheduling to bring wells on later in the year. AFF(3) is forecasted to be $80 to $85 million based on USD $80 WTI for the remainder of the year, with estimated FAFF(4) of $13 to $21 million. The Company's leverage metrics are projected to remain at levels which are among the lowest in our peer group with net debt to EBITDA(4) forecasted to be 0.5x – 0.6x for 2024.

Notes:

1. *See table in the Reader Advisories for key budget and underlying material assumptions related to the Company's 2024 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)	**Q2 2024**	Q1 2024	Q4 2023	Q3 2023
Oil and natural gas sales	**41,460**	37,997	47,631	46,672
Oil and natural gas sales, net of royalties	**36,394**	33,470	41,292	41,285
Profit	**5,415**	1,686	11,576	7,507
Profit per share, basic	**0.06**	0.02	0.13	0.08
Profit per share, diluted	**0.06**	0.02	0.13	0.08
Capital expenditures – PP&E	**5,389**	25,504	14,590	27,441
Capital expenditures – E&E	**767**	26	42	18
Property acquisitions (dispositions)	**-**	(25)	-	-
Net Corporate acquisitions(1)	**-**	-	-	-
Adjusted funds flow(2)	**20,145**	16,525	23,544	25,179
Adjusted funds flow per share, basic(3)	**0.22**	0.18	0.26	0.28
Adjusted funds flow per share, diluted(3)	**0.22**	0.18	0.26	0.28
Adjusted funds flow per boe(3)	**25.57**	21.10	26.67	30.40
Net debt(2)	**50,841**	59,897	45,679	48,810

	Q2 2023	Q1 2023	Q4 2022	Q3 2022
Oil and natural gas sales	39,762	45,301	58,161	56,985
Oil and natural gas sales, net of royalties	36,625	37,648	47,786	46,378
Profit	4,330	9,291	20,736	15,352
Profit per share, basic	0.05	0.11	0.24	0.18
Profit per share, diluted	0.05	0.10	0.23	0.17
Capital expenditures – PP&E	12,758	29,568	13,616	24,511
Capital expenditures – E&E	16	32	31	31
Property acquisitions (dispositions)	-	327	-	-
Net Corporate acquisitions(1)	-	-	(321)	89
Adjusted funds flow(2)	21,768	21,296	30,271	30,232
Adjusted funds flow per share, basic(3)	0.25	0.24	0.35	0.35
Adjusted funds flow per share, diluted(3)	0.24	0.24	0.33	0.33
Adjusted funds flow per boe(3)	28.23	26.23	34.19	34.61
Net debt(2)	41,821	46,204	32,963	45,615

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

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

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

InPlay's capital program for 2022 consisted of $77.6 million of development capital. The Company drilled, completed and brought on production six (6.0 net) extended reach horizontal ("ERH") wells in Pembina, ten (9.3 net) ERH wells on our Prairie Storm assets, two (2.0 net) Belly River wells and one (0.2 net) non-operated Willesden Green ERH well.

During 2022, InPlay reduced its net debt by 59% to $32.9 million at December 31, 2022 from $80.2 million at December 31, 2021.

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 first half of 2024 consisted of $31.7 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, three (3.0 net) ERH wells in Pembina and three (0.65 net) non-operated Willesden Green ERH wells during the first quarter of 2024, with the majority of these new wells coming on production late in March. The Company also drilled one (1.0 net) Belly River well during the second quarter of 2024 which is expected to be on production in the third quarter and started drilling one (1.0 net) Willesden Green Glauconite well in June. Approximately $2.9 million was spent on the optimization of wells during the first half of 2024 where pumps in older, low-rate horizontal wells have been lowered.

SELECTED ANNUAL INFORMATION

Years ended December 31 (in thousands, except per share amounts)	**2023**	2022	2021
Total oil and natural gas sales(1)	**179,366**	238,590	113,854
Oil and natural gas sales, net of royalties(1)	**156,850**	200,198	102,259
Profit	**32,702**	83,896	115,071
Profit per share, basic	**0.37**	0.97	1.65
Profit per share, diluted	**0.36**	0.92	1.61
Total assets	**472,956**	430,911	406,484
Total bank debt	**47,161**	29,210	79,127
Total net debt(2)	**45,679**	32,963	80,196

(1) The oil and natural gas sales exclude realized and unrealized gains (losses) on risk management derivative contracts: 2023 excludes $3.6 million realized gain and ($1.7 million) unrealized loss; 2022 excludes ($6.6 million) realized loss and $2.4 million unrealized gain; and 2021 excludes ($13.1 million) realized loss and $1.0 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 before corporate acquisitions 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.

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 Senior 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 six months ended June 30, 2024. All references to adjusted funds flow throughout this document are calculated as funds flow adjusting for decommissioning expenditures. 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 six months ended June 30, 2024. 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:

- 2024 guidance based on the planned capital program of $64 - $67 million including forecasts of 2024 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 2024 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; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

Forward-looking statements regarding InPlay are based on certain key expectations and assumptions of InPlay concerning anticipated financial performance, business prospects, strategies, regulatory developments, current commodity prices and exchange rates, applicable royalty rates, tax laws, future well production rates and reserve volumes, future operating costs, the performance of existing wells, the success of its exploration and development activities, the sufficiency and timing of budgeted capital expenditures in carrying out planned activities, the availability and cost of labor and services, the impact of increasing competition, conditions in general economic and financial markets, availability of drilling and related equipment effects of regulation by governmental agencies, the ability to obtain financing on acceptable terms which are subject to change based on commodity prices, 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 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 2024 capital budget and associated guidance are subject to change in light of, among other factors, 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 2024 financial outlook and 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 guidance for 2024 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 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; the timing and amount of purchases under the Company's NCIB; 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.

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 defer materially from those anticipated in such forward-looking information or statements including, without limitation: the continuing impact of the Russia/Ukraine conflict and war in the Middle East; inflation and the risk of a global recession; changes in our planned 2024 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 we operate; changes in the demand for or supply of our 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 our properties; changes in our credit structure, increased debt levels or debt service requirements; inaccurate estimation of our light crude oil and natural gas reserve and resource volumes; limited, unfavorable 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 our Annual Information Form and our MD&A.

This document contains future-oriented financial information and financial outlook information (collectively, "FOFI") about InPlay's financial and leverage targets and objectives, potential dividends, share buybacks and beliefs underlying our Board approved 2024 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 2024 capital program and associated guidance and estimates include:

- 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 2024 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 Company's 2024 guidance remains the same as previously released January 29, 2024 except as noted below. The key budget and underlying material assumptions used by the Company in the development of its 2024 guidance are as follows:

		Actuals FY 2023	Updated Guidance FY 2024	Previous Guidance FY 2024(1)
WTI	US$/bbl	$77.62	$79.38	$79.61
NGL Price	$/boe	$36.51	$35.40	$36.65
AECO	$/GJ	$2.50	$1.85	$1.90
Foreign Exchange Rate	CDN$/US$	0.74	0.73	0.73
MSW Differential	US$/bbl	$3.25	$4.55	$4.50
Production	Boe/d	9,025	8,700 – 9,000	9,000 – 9,500
Revenue	$/boe	54.45	51.00 – 56.00	52.25 – 57.25
Royalties	$/boe	6.84	6.40 – 7.90	6.40 – 7.90
Operating Expenses	$/boe	15.05	13.00 – 15.25	12.75 – 15.75
Transportation	$/boe	0.95	0.85 – 1.10	0.85 – 1.10
Interest	$/boe	1.65	1.80 – 2.40	1.50 – 2.00
General and Administrative	$/boe	3.13	2.50 – 3.25	2.50 – 3.25
Hedging loss (gain)	$/boe	(1.10)	(0.00) – (0.50)	(0.00) – (0.50)
Decommissioning Expenditures	$ millions	$3.3	$4.0 – $4.5	$4.0 – $4.5
Adjusted Funds Flow	$ millions	$92	$80 – $85	$90 – $97
Dividends	$ millions	$16	$16 – $17	$16 – $17

		Actuals FY 2023	Updated Guidance FY 2024	Previous Guidance FY 2024(1)
Adjusted Funds Flow	$ millions	$92	$80 – $85	$90 – $97
Capital Expenditures	$ millions	$84.5	$64 – $67	$64 – $67
Free Adjusted Funds Flow	$ millions	$7	$13 – $21	$23 – $33

		Actuals FY 2023	Updated Guidance FY 2024	Previous Guidance FY 2024(1)
Revenue	$/boe	54.45	51.00 – 56.00	52.25 – 57.25
Royalties	$/boe	6.84	6.40 – 7.90	6.40 – 7.90
Operating Expenses	$/boe	15.05	13.00 – 15.25	12.75 – 15.75
Transportation	$/boe	0.95	0.85 – 1.10	0.85 – 1.10
Operating Netback	$/boe	31.61	28.00 – 33.00	30.00 – 35.00
Operating Income Profit Margin		58%	58%	59%

		Actuals FY 2023	Updated Guidance FY 2024	Previous Guidance FY 2024(1)
Adjusted Funds Flow	$ millions	$92	$80 – $85	$90 – $97
Interest	$/boe	1.65	1.90 – 2.40	1.50 – 2.00
EBITDA	$ millions	$98	$87 – $92	$96 – $103
Net Debt	$ millions	$46	$48 – $53	$37 – $44
Net Debt/EBITDA		0.5	0.5 – 0.6	0.4 – 0.5

(1) As previously released May 9, 2024.

- 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 press release consists of the constituent product types as defined in NI 51-101 and their respective quantities disclosed in the table below:

	Light and Medium Crude oil (bbls/d)	NGLs (boe/d)	Conventional Natural gas (Mcf/d)	Total (boe/d)
Q1 2023 Average Production	3,788	1,458	22,648	9,020
Q2 2023 Average Production	3,658	1,187	21,772	8,474
2023 Average Production	3,822	1,396	22,839	9,025
Q1 2024 Average Production	3,452	1,487	22,000	8,605
Q2 2024 Average Production	3,671	1,438	21,291	8,657
2024 Updated Annual Guidance	3,735	1,435	22,080	8,850(1)
2024 Previous Annual Guidance	4,010	1,455	22,710	9,250(2)

Notes:

1. *This reflects the mid-point of the Company's 2024 production guidance range of 9,000 to 9,500 boe/d.*
2. *With respect to forward-looking production guidance, product type breakdown is based upon management's expectations based on reasonable assumptions but are subject to variability based on actual well results.*

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 ("Nl 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