MANAGEMENT'S DISCUSSION AND ANALYSIS
For the three and six months ended June 30, 2025

This management's discussion and analysis of financial condition and results of operations ("MD&A") of Obsidian Energy Ltd. ("Obsidian Energy", the "Company", "we", "us", "our") should be read in conjunction with the Company's unaudited interim condensed consolidated financial statements for the three and six months ended June 30, 2025 and the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2024. The date of this MD&A is July 29, 2025. All dollar amounts contained in this MD&A are expressed in millions of Canadian dollars unless noted otherwise.

Throughout this MD&A and in other materials disclosed by the Company, we adhere to generally accepted accounting principles ("GAAP"), however the Company also employs certain non-GAAP measures to analyze financial performance, financial position, and cash flow, including funds flow from operations, netback, sales, gross revenues, net operating costs, net debt and free cash flow. Additionally, other financial measures are also used to analyze performance. These non-GAAP and other financial measures do not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable to similar measures provided by other issuers. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss) and cash flow from operating activities, as indicators of our performance.

This MD&A also contains oil and natural gas information and forward-looking statements. Please see the Company's disclosure under the headings "Non-GAAP and Other Financial Measures", "Oil and Natural Gas Information", and "Forward-Looking Statements" included at the end of this MD&A.

Quarterly Financial Summary
(millions, except per share and production amounts) (unaudited)

Three months ended	**Jun. 30 2025**	Mar. 31 2025	Dec. 31 2024	Sep. 30 2024	Jun. 30 2024	Mar. 31 2024	Dec. 31 2023	Sep. 30 2023
Production revenues	**$ 136.3**	$ 211.0	$ 213.6	$ 218.2	$ 208.4	$ 177.3	$ 173.3	$ 200.4
Cash flow from operating activities	**55.2**	96.7	115.0	110.3	77.9	58.7	117.7	95.3
Basic per share (1)	**0.79**	1.32	1.55	1.45	1.02	0.76	1.49	1.18
Diluted per share (1)	**0.75**	1.27	1.49	1.40	0.98	0.73	1.44	1.15
Funds flow from operations (2)	**65.8**	100.1	107.7	124.7	115.2	84.4	97.0	98.9
Basic per share (3)	**0.94**	1.36	1.45	1.64	1.51	1.09	1.23	1.22
Diluted per share (3)	**0.90**	1.31	1.39	1.58	1.44	1.05	1.18	1.19
Net income (loss)	**15.3**	15.4	(284.8)	33.2	37.1	11.9	34.3	24.8
Basic per share	**0.22**	0.21	(3.83)	0.44	0.48	0.15	0.44	0.31
Diluted per share	**$ 0.21**	$ 0.20	$ (3.83)	$ 0.42	$ 0.46	$ 0.15	$ 0.42	$ 0.30
Production								
Light oil (bbl/d)	**6,314**	12,727	13,271	13,722	13,782	13,079	12,176	12,452
Heavy oil (bbl/d)	**12,041**	10,887	11,621	10,624	7,026	6,748	5,851	6,260
NGLs (bbl/d)	**2,189**	3,072	3,176	3,148	3,193	2,783	2,614	2,708
Natural gas (mmcf/d)	**50**	70	72	73	71	70	68	69
Total (boe/d)(4)	**28,943**	38,416	40,119	39,714	35,773	34,238	31,974	32,937

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(3) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures".
(4) Disclosure of production on a per boe basis in this MD&A consists of the constituent product types and their respective quantities. See also "Supplemental Production Disclosure" and "Oil and Natural Gas Information".

Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow

	Three months ended June 30		Six months ended June 30	
(millions, except per share amounts)	**2025**	2024	**2025**	2024
Cash flow from operating activities	**$ 55.2**	$ 77.9	**$ 151.9**	$ 136.6
Change in non-cash working capital	**4.3**	29.7	**(1.5)**	43.1
Decommissioning expenditures	**4.0**	4.0	**10.6**	14.1
Onerous office lease settlements	**-**	2.2	**0.7**	4.5
Deferred financing costs	**(0.6)**	(0.6)	**(1.0)**	(1.2)
Restructuring	**0.7**	-	**0.8**	-
Transaction costs	**2.2**	1.4	**4.4**	1.4
Other expenses	**-**	0.6	**-**	1.1
Funds flow from operations (1)	**65.8**	115.2	**165.9**	199.6
Capital expenditures	**(40.2)**	(59.2)	**(168.6)**	(173.5)
Decommissioning expenditures	**(4.0)**	(4.0)	**(10.6)**	(14.1)
Free Cash Flow (1)	**$ 21.6**	$ 52.0	**$ (13.3)**	$ 12.0
Per share – funds flow from operations (2)				
Basic per share	**$ 0.94**	$ 1.51	**$ 2.31**	$ 2.60
Diluted per share	**$ 0.90**	$ 1.44	**$ 2.23**	$ 2.50

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(2) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures".

Cash flow from operating activities and funds flow from operations decreased in Q2 2025 compared to Q2 2024 primarily due to lower production revenues, as a result of lower commodity prices and lower production levels due to the disposition of our operated Pembina assets at the start of Q2 2025. The disposition of the operated Pembina assets and associated lower production and lower revenues also impacted funds flow from operations for the first six months of 2025 compared to the 2024 period.

Pembina Disposition

On April 7, 2025, the Company closed the disposition (the "Pembina disposition") to InPlay Oil Corp. ("InPlay") of our operated Pembina (Cardium) assets (the "Pembina Assets"). Total consideration for the transaction included approximately $211 million of cash (inclusive of interim closing adjustments), 9,139,784 common shares of InPlay ("InPlay Shares") (updated to reflect InPlay's consolidation of its common shares on a one for six basis effective April 14, 2025) and a $15 million value associated with acquiring InPlay's 34.6 percent interest in the Willesden Green Cardium Unit #2 property. The transaction included all the Company's assets in Pembina, with the exception of our non-operated interest in Pembina Cardium Unit #11 which we retain. The transaction had an effective date of December 1, 2024. As part of the transaction, InPlay assumed all assets and liabilities associated with the Pembina Assets, including the Company’s decommissioning liabilities.

This transaction has further strengthened our balance sheet, with the cash proceeds from the transaction used to initially pay down outstanding debt on our syndicated credit facility on closing. Subsequent to June 30, 2025, the Company announced that a third party made a non-binding offer to Obsidian Energy to acquire the Company’s entire common share position in InPlay, consisting of 9,139,784 InPlay Shares, at a price per InPlay Share in excess of the $9.59 closing price for such shares on the Toronto Stock Exchange ("TSX") as of July 15, 2025. The Company has entered into negotiations with the third party and InPlay in respect of the potential transaction outlined in the non-binding offer and has agreed to engage exclusively with the third party in respect of the potential transaction until August 1, 2025.

Business Strategy

Upon close of the Pembina Disposition, the Company has a more balanced portfolio of heavy and light oil assets. In Peace River over the past two years we have more than doubled our production in the area through a focused development program. With a significant land base of greater than 700 net sections, we expect to be able to continue to grow our Clearwater and Bluesky production through further development and delineation of existing and establishing new fields in the area. With a now more focused light oil asset base, we also expect to be able to grow our light assets through ongoing development. The pace and level of future development and growth will be subject to the macro-economic environment (commodity prices and service costs) as we look to generate acceptable returns and maintain the Company's financial strength.

In 2023, we began our return of capital initiative through our share buyback program under our normal course issuer bid ("NCIB"). This program has further enhanced shareholder returns, specifically through a focus on per share growth. Including purchases made subsequent to Q2 2025, we have re-purchased and cancelled a total of approximately 16.7 million common shares (approximately 20 percent of our outstanding shares) for total consideration of $140.2 million since the inception of the NCIB in 2023. Purchases under the NCIB are subject to having $65 million of liquidity and otherwise complying with the terms of our current credit facilities.

The Company continued with our environmental remediation efforts in the first half of 2025 with a focus on abandoning and reclaiming inactive fields.

Business Environment

The following table outlines quarterly averages for benchmark prices and Obsidian Energy's realized prices for the previous eight quarters.

	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023	Q3 2023
Benchmark prices								
WTI oil ($US/bbl)	**$ 63.74**	$ 71.42	$ 70.27	$ 75.09	$ 80.57	$ 76.96	$ 78.32	$ 82.26
Edm mixed sweet par price (CAD$/bbl)	**84.04**	95.00	94.39	97.60	105.41	92.21	99.46	107.89
Western Canada Select (CAD$/bbl)	**73.89**	84.04	80.67	83.80	91.82	77.80	76.76	93.07
NYMEX Henry Hub ($US/mmbtu)	**3.44**	3.65	2.79	2.16	1.89	2.24	2.88	2.55
AECO 5A Index (CAD$/mcf)	**1.69**	2.17	1.48	0.69	1.18	2.50	2.30	2.60
Foreign exchange rate (US/CAD)	**1.38**	1.43	1.40	1.37	1.37	1.35	1.36	1.34
Benchmark differentials								
WTI - Edm Light Sweet ($US/bbl)	**(2.84)**	(4.98)	(2.42)	(3.35)	(3.63)	(8.65)	(5.19)	(1.86)
WTI - Western Canadian Select Heavy ($US/bbl)	**(10.20)**	(12.65)	(12.54)	(13.51)	(13.55)	(19.33)	(21.88)	(12.89)
Average sales price (1) (2)								
Light oil (CAD$/bbl)	**91.09**	99.46	96.95	100.09	107.61	94.82	100.38	109.56
Heavy oil (CAD$/bbl)	**61.27**	70.14	67.70	73.73	79.73	60.39	58.53	80.14
NGLs (CAD$/bbl)	**39.42**	53.49	44.27	48.92	48.92	50.43	55.65	49.71
Total liquids (CAD$/bbl)	**68.11**	82.21	78.88	84.04	91.64	79.08	82.85	93.40
Natural gas (CAD$/mcf)	**$ 2.00**	$ 2.18	$ 1.53	$ 0.86	$ 1.33	$ 2.38	$ 2.63	$ 2.65

(1) Excludes the impact of realized hedging gains or losses.
(2) Supplementary financial measures. See "Non-GAAP and Other Financial Measures".

Oil

WTI prices averaged US$63.74 per barrel during Q2 2025, with WTI prices starting the quarter at approximately US$63 per barrel in April before increasing to over US$67 per barrel in June. The increase late in the quarter was primarily driven by the Iran-Israel conflict and associated potential supply risk.

WCS differentials averaged US$10.20 per bbl for Q2 2025 compared to US$12.65 per bbl in Q1 2025. MSW differentials averaged US$2.84 for Q2 2025. Alberta wildfires and planned maintenance both led to a reduction in supply which contributed to the improved prices.

The Company currently has the following oil hedging contracts in place on a weighted average basis:

Type	Volume (bbls/d)	Remaining Term		Price ($/bbl)
WTI Swap	12,375	July 2025	$	86.29
WTI Swap	11,750	August 2025		90.73
WTI Swap	9,500	September 2025		92.18
WTI Swap	7,500	October 2025		90.67
WTI Swap	4,500	November 2025		90.47
WTI Swap	4,000	December 2025		90.23
WCS Differential	7,750	Q3 2025		(18.83)
WCS Differential	6,000	Q4 2025		(19.30)
MSW Differential	500	Q3 2025	$	(6.59)

Natural Gas

The average NYMEX Futures price for the quarter settled at US$3.44 per mmbtu. In Alberta, AECO 5A prices for Q2 2025 averaged $1.69 per mcf, compared to $2.17 per mcf in Q1 2025. Increased supply which resulted in higher inventory levels suppressed prices throughout the quarter, with AECO 5A settling at an average price of $0.80 per mcf in June, a low for the quarter.

The Company currently has the following natural gas hedging contracts in place on a weighted average basis:

Type	Volume (mcf/d)	Remaining Term		Price ($/mcf)
AECO Swap	25,118	July 2025 - October 2025	$	2.24
AECO Swap	13,033	November 2025 - March 2026		3.55
AECO Swap	6,635	April 2026 - October 2026		2.64
AECO Collar	1,896	July 2025 - October 2025	$	2.11 - 2.64

RESULTS OF OPERATIONS

Average Sales Prices [1]

	Three months ended June 30			Six months ended June 30		
	2025	2024	% change	**2025**	2024	% change
Light oil (per bbl)	**$ 91.09**	$ 107.61	(15)	**$ 96.66**	$ 101.38	(5)
Heavy oil (per bbl)	**61.27**	79.73	(23)	**65.46**	70.26	(7)
NGL (per bbl)	**39.42**	48.92	(19)	**47.60**	49.62	(4)
Total liquids (per bbl)	**68.11**	91.64	(26)	**76.04**	85.55	(11)
Realized risk management loss (per bbl)	**(1.11)**	(0.17)	553	**(0.54)**	(0.10)	440
Total liquids, net (per bbl)	**67.00**	91.47	(27)	**75.50**	85.45	(12)
Natural gas (per mcf)	**2.00**	1.33	50	**2.11**	1.85	14
Realized risk management gain (per mcf)	**0.08**	0.67	(88)	**0.30**	0.64	(53)
Natural gas net (per mcf)	**2.08**	2.00	4	**2.41**	2.49	(3)
Weighted average (per boe)	**51.83**	64.11	(19)	**57.09**	60.67	(6)
Realized risk management gain (loss) (per boe)	**(0.64)**	1.20	N/A	**0.17**	1.22	(86)
Weighted average net (per boe)	**$ 51.19**	$ 65.31	(22)	**$ 57.26**	$ 61.89	(7)

(1) Supplementary financial measures. See "Non-GAAP and Other Financial Measures".

Production

	Three months ended June 30			Six months ended June 30		
Daily production	**2025**	2024	% change	**2025**	2024	% change
Light oil (bbl/d)	**6,314**	13,782	(54)	**9,503**	13,430	(29)
Heavy oil (bbl/d)	**12,041**	7,026	71	**11,467**	6,887	67
NGL (bbl/d)	**2,189**	3,193	(31)	**2,628**	2,989	(12)
Natural gas (mmcf/d)	**50**	71	(30)	**60**	70	(14)
Total production (boe/d)	**28,943**	35,773	(19)	**33,653**	35,006	(4)

In the 2025 periods, total production levels were lower compared to the 2024 periods primarily due to the Pembina Disposition which closed at the start of Q2 2025. Production associated with the Pembina assets averaged approximately 11,000 boe/d in Q1 2025.

The Company has grown production in our Peace River asset over the past two years which has resulted in an increase in our heavy oil volumes year-over-year. In the first six months of 2025, a total of 37 wells (32.6 net) were drilled and 39 wells (34.6 net) were brought on production.

Average production within the Company’s key development areas and within the Company’s Legacy asset area was as follows:

	Three months ended June 30			Six months ended June 30		
Daily production (boe/d) (1)	**2025**	2024	% change	**2025**	2024	% change
Cardium	**14,462**	25,702	(44)	**19,687**	24,880	(21)
Peace River	**12,827**	7,222	78	**12,221**	7,254	68
Viking	**1,338**	2,538	(47)	**1,428**	2,521	(43)
Legacy	**316**	311	2	**317**	351	(10)
Total	**28,943**	35,773	(19)	**33,653**	35,006	(4)

(1) Refer to “Supplemental Production Disclosure” for details by product type.

Netbacks

	Three months ended June 30		Six months ended June 30	
(per boe)	**2025**	2024	**2025**	2024
Netback:				
Sales price (1) (3)	**$ 51.83**	$ 64.11	**$ 57.09**	$ 60.67
Risk management gain (loss) (2)	**(0.64)**	1.20	**0.17**	1.22
Royalties	**(6.03)**	(8.34)	**(7.27)**	(7.71)
Transportation	**(4.49)**	(4.15)	**(4.69)**	(4.05)
Net operating costs (3)	**(13.54)**	(13.83)	**(14.78)**	(13.87)
Netback (3)	**$ 27.13**	$ 38.99	**$ 30.52**	$ 36.26
	(boe/d)	(boe/d)	**(boe/d)**	(boe/d)
Production	**28,943**	35,773	**33,653**	35,006

(1) Includes the impact of commodities purchased from and sold to third parties of $0.2 million (2024 – $0.3 million) for the second quarter of 2025 and $0.5 million (2024 – $0.8 million) for the first six months of 2025. See "Production Revenues" below for a reconciliation of "Sales" to "Production revenues".
(2) Realized risk management gains (losses) on commodity contracts.
(3) Non-GAAP ratios. See "Non-GAAP and Other Financial Measures".

The Company's netback decreased in the 2025 periods compared to the 2024 periods due to lower oil prices which led to lower realized prices. Transportation costs were also higher as a result of our increasing Peace River production. Net operating costs were lower in Q2 2025 due to the Pembina Disposition partially offset by our growing Peace River production, which primarily resulted in an overall increase in first half 2025 net operating costs.

(millions)	Three months ended June 30 2025	2024	Six months ended June 30 2025	2024
Netback:				
Sales (1) (3)	**$ 136.5**	$ 208.7	**$ 347.8**	$ 386.5
Risk management gain (loss) (2)	**(1.7)**	4.0	**1.0**	7.8
Royalties	**(15.9)**	(27.1)	**(44.3)**	(49.1)
Transportation	**(11.8)**	(13.5)	**(28.6)**	(25.8)
Net operating costs (3)	**(35.6)**	(45.1)	**(90.0)**	(88.3)
Netback (3)	**$ 71.5**	$ 127.0	**$ 185.9**	$ 231.1

(1) Includes the impact of commodities purchased from and sold to third parties of $0.2 million (2024 – $0.3 million) for the second quarter of 2025 and $0.5 million (2024 – $0.8 million) for the first six months of 2025. See "Production Revenues" below for a reconciliation of "Sales" to "Production revenues".
(2) Realized risk management gains (losses) on commodity contracts.
(3) Non-GAAP financial measures. See "Non-GAAP and Other Financial Measures".

Production Revenues

A reconciliation from production revenues to gross revenues is as follows:

(millions)	Three months ended June 30 2025	2024	Six months ended June 30 2025	2024
Production revenues	**$ 136.3**	$ 208.4	**$ 347.3**	$ 385.7
Sales of commodities purchased from third parties	**1.3**	1.7	**3.3**	5.5
Less: Commodities purchased from third parties	**(1.1)**	(1.4)	**(2.8)**	(4.7)
Sales (1)	**136.5**	208.7	**347.8**	386.5
Realized risk management gain (loss) (2)	**(1.7)**	4.0	**1.0**	7.8
Gross revenues (1)	**$ 134.8**	$ 212.7	**$ 348.8**	$ 394.3

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(2) Relates to realized risk management gains on commodity contracts.

The Company's production revenues and gross revenues were lower in the 2025 periods compared to the comparable periods in 2024, mainly due to lower realized oil prices and lower production volumes as a result of the Pembina Disposition early in Q2 2025.

Change in Gross Revenues (1)

(millions)	
Gross revenues – January 1 – June 30, 2024	$ 394.3
Decrease in liquids production	(15.1)
Decrease in liquids prices	(23.0)
Decrease in natural gas production	(3.4)
Increase in natural gas prices	2.8
Increase in realized oil risk management loss	(1.9)
Decrease in realized natural gas risk management gain	(4.9)
Gross revenues – January 1 – June 30, 2025 (2)	$ 348.8

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".
(2) Excludes processing fees and other income.

Royalties

	Three months ended June 30		Six months ended June 30	
	2025	2024	**2025**	2024
Royalties (millions)	**$ 15.9**	$ 27.1	**$ 44.3**	$ 49.1
Average royalty rate (1)	**12%**	13%	**13%**	13%

(1) Excludes effects of risk management activities and other income.

For the 2025 periods, absolute royalties decreased from the comparable 2024 periods which was largely attributed to lower oil prices and lower production in the second quarter of 2025 due to the Pembina Disposition. The average royalty rate remained relatively flat for the 2025 periods compared to the 2024 periods.

Expenses

	Three months ended June 30		Six months ended June 30	
(millions)	**2025**	2024	**2025**	2024
Net operating (1)	**$ 35.6**	$ 45.1	**$ 90.0**	$ 88.3
Transportation	**11.8**	13.5	**28.6**	25.8
Financing	**8.7**	12.8	**21.4**	24.8
Share-based compensation	**$ (0.2)**	$ 0.9	**$ 2.7**	$ 9.9

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".

Operating

A reconciliation of operating costs to net operating costs is as follows:

	Three months ended June 30		Six months ended June 30	
(millions)	**2025**	2024	**2025**	2024
Operating costs	**$ 39.7**	$ 49.1	**$ 98.7**	$ 98.4
Less processing fees	**(2.6)**	(2.9)	**(5.4)**	(6.8)
Less road use recoveries	**(1.5)**	(1.7)	**(3.3)**	(3.8)
Add realized power risk management loss	**-**	0.6	**-**	0.5
Net operating costs (1)	**$ 35.6**	$ 45.1	**$ 90.0**	$ 88.3

(1) Non-GAAP financial measure. See “Non-GAAP and Other Financial Measures”.

On an absolute basis, for Q2 2025 both operating and net operating costs were lower than the 2024 comparable period mainly due to our lower production base as a result of the Company closing the Pembina Disposition at the start of the quarter. For the first six months of 2025, operating and net operating costs were roughly flat compared to the 2024 period as our higher production base during Q1 2025 led to higher costs, but was offset by our lower production base in Q2 2025 as a result of the Pembina Disposition.

Transportation

The Company continues to utilize multiple sales points in the Peace River area to increase realized prices. New wells drilled in the Peace River area over the past year resulted in higher production and thus higher transportation costs in the first six months of 2025 compared to the 2024 period.

Financing

Financing expense consists of the following:

(millions)	Three months ended June 30 2025	2024	Six months ended June 30 2025	2024
Interest	**$ 5.1**	$ 7.7	**$ 12.6**	$ 14.4
Accretion on decommissioning liability	**2.7**	4.1	**7.3**	8.3
Accretion on office lease provision	**-**	0.1	**-**	0.3
Accretion on discount of senior unsecured notes	**0.1**	0.1	**0.2**	0.2
Accretion on lease liabilities	**0.1**	0.2	**0.2**	0.3
Loss on repurchased senior unsecured notes	**0.1**	-	**0.1**	0.1
Deferred financing costs	**0.6**	0.6	**1.0**	1.2
Financing	**$ 8.7**	$ 12.8	**$ 21.4**	$ 24.8

Obsidian Energy's debt structure includes short-term borrowings under our syndicated credit facility and term financing through our senior unsecured notes. Interest charges were lower in 2025 compared to 2024 mainly due to lower drawings on our syndicated credit facility following the Pembina Disposition as the proceeds received from the transaction were used to reduce the amount outstanding under our syndicated credit facility.

The Company has a reserve-based syndicated credit facility which is subject to a semi-annual borrowing base redetermination (typically completed in May and November of each year). The aggregate amount available under the syndicated credit facility is $235.0 million and the revolving period and maturity dates are set at May 31, 2026 and May 31, 2027, respectively.

At June 30, 2025, the Company had senior unsecured notes outstanding totaling $112.2 million which mature on July 27, 2027. The senior unsecured notes were initially issued at a price of $980 per $1,000 principal amount resulting in aggregate gross proceeds of $125.0 million and at an interest rate of 11.95 percent. The senior unsecured notes are direct senior unsecured obligations of Obsidian Energy ranking equal with all other present and future senior unsecured indebtedness of the Company.

In April 2025, the Company repurchased $2.0 million of our senior unsecured notes on the open market at a price of $1,027.5 per $1,000 principal amount.

As part of the terms of the senior unsecured notes, the Company is required, in certain circumstances, to make a repurchase offer (the "Repurchase Offer") at a price of $1,030 per $1,000 principal amount to an aggregate amount of $63.8 million (including open market purchases), which has been reduced to $48.4 million based on previous Repurchase Offers and open market purchases. The obligation to make a Repurchase Offer is based on free cash flow for the six months ended June 30 (typically offered in August) and based on free cash flow for the six months ended December 31 (typically offered in March). Minimum available liquidity thresholds and projected leverage ratios under the Company's syndicated credit facilities are also required to be met in order to proceed with a Repurchase Offer. For the first six months of 2025, based on free cash flow available and our liquidity estimates we expect to make a $48.4 million Repurchase Offer in August 2025. This amount was recorded within the current portion of long-term debt at June 30, 2025.

At June 30, 2025, letters of credit totaling $4.3 million were outstanding (December 31, 2024 – $4.4 million) that reduce the amount otherwise available to be drawn on our syndicated credit facility.

Share-Based Compensation

Share-based compensation expense relates to options ("Options") granted under the Company's Stock Option Plan, restricted share units ("RSUs") granted under the Restricted and Performance Share Unit Plan ("RPSU plan"), deferred share units ("DSUs") granted under the Deferred Share Unit Plan ("DSU plan") and performance share units ("PSUs") granted under the RPSU plan.

Share-based compensation expense consisted of the following:

(millions)	Three months ended June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
DSUs	**$ (1.5)**	$ (1.8)	**$ (1.2)**	$ 2.6
PSUs	**(1.1)**	0.2	**(0.6)**	1.8
NTIP (1)	**-**	0.2	**-**	1.1
Liability based incentive plans	**$ (2.6)**	$ (1.4)	**$ (1.8)**	$ 5.5
RSUs	**$ 1.9**	$ 1.7	**$ 3.6**	$ 3.4
Options	**0.5**	0.6	**0.9**	1.0
Equity based incentive plans	**2.4**	2.3	**4.5**	4.4
Share-based compensation	**$ (0.2)**	$ 0.9	**$ 2.7**	$ 9.9

(1) Restricted awards granted under the Non-Treasury Incentive Award Plan ("NTIP") were classified as a liability and were settled in cash. There were no outstanding restricted awards under the NTIP at June 30, 2025.

The change in share price at the balance sheet date results in a mark-to-market valuation which is used to calculate the PSU and DSU future obligations. On June 30, 2025, the Company's share price closed at $7.58 per share compared to $8.36 per share on December 31, 2024 and $10.24 per share on June 30, 2024 on the TSX.

General and Administrative Expenses ("G&A")

(millions, except per boe amounts)	Three months ended June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
Gross	**$ 9.9**	$ 10.0	**$ 20.8**	$ 20.6
Per boe (1)	**3.78**	3.06	**3.42**	3.23
Net (2)	**5.0**	4.9	**10.6**	10.4
Per boe (1)	**$ 1.92**	$ 1.49	**$ 1.74**	$ 1.63

(1) Supplementary financial measure. See “Non-GAAP and Other Financial Measures”.
(2) Net G&A includes the impact of overhead recoveries and capitalized G&A.

On an absolute basis, G&A was relatively unchanged in the 2025 periods compared to the 2024 periods as staff costs were relatively consistent year-over-year. On a per boe basis, the impact of the Pembina Disposition in Q2 2025 led to higher costs in the 2025 periods compared to the 2024 periods.

Depletion, Depreciation and Impairment

(millions)	Three months ended June 30 2025	Three months ended June 30 2024	Six months ended June 30 2025	Six months ended June 30 2024
Depletion and depreciation (“D&D”)	**$ 45.5**	$ 59.3	**$ 88.7**	$ 114.3
PP&E Impairment	**$ 1.2**	$ 1.6	**$ 13.3**	$ 2.5

The Company’s D&D expense decreased in the 2025 periods compared to the 2024 periods due to a combination of the Pembina Assets being classified as assets held for sale in Q1 2025 and no longer being depleted and then the close of the Pembina Disposition early in Q2 2025, which reduced production levels.

Prior to the close of the Pembina Disposition in April 2025, the Company classified these assets as held for sale. In 2025, the Pembina Assets were recorded at the lesser of fair value less costs to sell and their carrying amount, resulting in a non-cash, before tax, impairment loss of $15.4 million. The impairment expense was recorded as additional depletion, depreciation and impairment on the Consolidated Statements of Income.

During the first six months of 2025, we recorded a $14.2 million impairment reversal (2024 - $2.5 million) in our Legacy cash generating unit ("Legacy CGU") due to a reduction in the decommissioning liability in the area. The Legacy CGU has no recoverable amount, as such changes in our decommissioning liability are expensed or recovered each period.

Taxes

	Three months ended June 30		Six months ended June 30	
(millions)	**2025**	2024	**2025**	2024
Deferred income tax expense	**$ 4.3**	$ 11.7	**$ 9.3**	$ 16.0

The Company previously recognized a deferred tax asset, as we expect to have sufficient taxable profits in future years in order to fully utilize the remaining deferred tax asset balance. The deferred income tax expense was due to the Company's net income and resultant reduction of our deferred income tax asset.

Net Income

	Three months ended June 30		Six months ended June 30	
(millions, except per share amounts)	**2025**	2024	**2025**	2024
Net income	**$ 15.3**	$ 37.1	**$ 30.7**	$ 49.0
Basic per share	**0.22**	0.48	**0.43**	0.64
Diluted per share	**$ 0.21**	$ 0.46	**$ 0.41**	$ 0.61

Net income was lower in the 2025 periods as a result of the Company's lower production revenues due to lower realized oil prices and lower production volumes as a result of the Pembina Disposition early in Q2 2025. This was partially offset by lower depletion and depreciation expense from the combination of the Pembina Assets being classified as assets held for sale in Q1 2025 and no longer being depleted and the subsequent closing of the Pembina Disposition in early Q2 2025.

Capital Expenditures

	Three months ended June 30		Six months ended June 30	
(millions)	**2025**	2024	**2025**	2024
Drilling and completions	**$ 14.6**	$ 37.7	**$ 102.4**	$ 129.0
Well equipping and facilities	**25.0**	21.2	**58.8**	43.9
Land and geological/geophysical	**0.5**	-	**6.9**	-
Corporate	**0.1**	0.3	**0.5**	0.6
Capital expenditures	**$ 40.2**	$ 59.2	**$ 168.6**	$ 173.5
Property acquisitions, net	**(210.9)**	84.9	**(210.9)**	84.9
Total	**$ (170.7)**	$ 144.1	**$ (42.3)**	$ 258.4

Capital expenditures in Q2 2025 focused on bringing wells on production from our active development program in Peace River earlier in the year. Overall, capital expenditures were lower in Q2 2025 than Q2 2024 as we moderated capital spending in the period in response to lower commodity prices and volatility in commodity markets.

For the first six months of 2025, 39 (34.6 net) wells were brought on production, including operated and non-operated activities, which included 30 (28.4 net) wells in Peace River and 9 (6.2 net) wells in the Cardium.

Drilling

	Six months ended June 30			
	2025		2024	
(number of wells)	**Gross**	**Net**	Gross	Net
Oil	**35**	**31**	41	33
Gas	**-**	**-**	4	1
Injectors, stratigraphic and service	**2**	**2**	7	6
Total	**37**	**33**	52	40

The Company drilled 32 (30.4 net) operated wells, including injectors, during the first six months of 2025. In addition, the Company had non-operated working interests in 5 (2.2 net) wells that were drilled by various partners during the period.

Environmental and Climate Change

The oil and natural gas industry has a number of environmental risks and hazards and is subject to regulation by all levels of government. Environmental legislation includes, but is not limited to, operational controls, site rehabilitation requirements and restrictions on emissions of various substances produced in association with oil and natural gas operations. Compliance with such legislation is expected to require additional expenditures and a failure to comply may result in fines and penalties which could, in the aggregate and under certain assumptions, become material.

Obsidian Energy monitors our operations for environmental impacts and allocates capital to reclamation and other activities to help mitigate the impact on the areas in which the Company operates. The Company follows the Alberta Energy Regulator guidance under Directive 088 where a minimum amount of spending is required to abandon inactive sites.

Liquidity and Capital Resources

Net Debt

Net debt is the total of long-term debt and working capital deficiency as follows:

	As at	
(millions)	**June 30, 2025**	December 31, 2024
Long-term debt		
Syndicated credit facility	**$ 114.0**	$ 225.0
Senior unsecured notes	**112.2**	114.2
Unamortized discount of senior unsecured notes	**(0.9)**	(1.1)
Deferred financing costs	**(2.5)**	(2.7)
Total	**222.8**	335.4
Working capital deficiency		
Cash	**(1.6)**	-
Accounts receivable	**(68.1)**	(88.0)
Prepaid expenses and other	**(14.4)**	(12.0)
Bank overdraft	**-**	0.5
Accounts payable and accrued liabilities	**131.5**	175.8
Total	**47.4**	76.3
Net debt (1)	**$ 270.2**	$ 411.7

(1) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".

Net debt decreased compared to December 31, 2024, as a result of lower drawings under our syndicated credit facility and decreased working capital deficiency as our development program moderated in Q2 2025. On April 7, 2025, the Company closed the Pembina Disposition and used the cash proceeds of approximately $211 million (inclusive of interim closing adjustments) to reduce the amount outstanding under our syndicated credit facility.

Liquidity

The Company currently has a reserve-based syndicated credit facility with a borrowing limit of $235.0 million and senior unsecured notes totaling $112.2 million, due in July 2027. For further details on the Company's debt instruments please refer to the "Financing" section of this MD&A.

The Company actively manages our debt portfolio and considers opportunities to reduce or diversify our debt capital structure. Management contemplates both operating and financial risks and takes action as appropriate to limit the Company's exposure to certain risks. Management maintains close relationships with the Company's lenders and agents to monitor credit market developments. These actions and plans aim to increase the likelihood of maintaining the Company's financial flexibility and an appropriate capital program, supporting the Company's ongoing operations and ability to execute longer-term business strategies.

Investment in InPlay

On April 7, 2025, the Company closed the Pembina disposition. As part of the consideration, the Company received 9,139,784 InPlay Shares. The Company has classified our investment in InPlay as held for sale which is measured at the lower of carrying value and fair value less costs to sell. The initial valuation of the InPlay Shares was based on InPlay's closing share price on April 7, 2025 of $8.34 per share and classified as held for sale as we do not intend to be long term shareholders.

During Q2 2025, InPlay paid a cash dividend of $0.09 per common share per month, resulting in the Company receiving $2.5 million during the period. The dividends received from InPlay were recorded within other income.

Subsequent to June 30, 2025, the Company announced that a third party made a non-binding offer to Obsidian Energy to acquire the Company's entire common share position in InPlay, consisting of 9,139,784 InPlay Shares, at a price per InPlay Share in excess of the $9.59 closing price for such shares on the TSX as of July 15, 2025. The Company has entered into negotiations with the third party and InPlay in respect of the potential transaction outlined in the non-binding offer and has agreed to engage exclusively with the third party in respect of the potential transaction until August 1, 2025.

Financial Instruments

Obsidian Energy had the following financial instruments outstanding as at June 30, 2025. Fair values are determined using external counterparty information, which is compared to observable market data. The Company limits our credit risk by executing counterparty risk procedures which include transacting only with institutions within our syndicated credit facility or companies with high credit ratings, and by obtaining financial security in certain circumstances.

	Notional Volume (bbl/d)	Remaining Term		Price (C$/bbl)		Fair value (millions)
Oil						
WTI Swap	12,375	July 2025	$	86.29	$	(0.7)
WTI Swap	8,500	August 2025		91.46		1.4
WTI Swap	4,500	September 2025		95.66		1.4
WCS Differential	1,750	Q3 2025		(17.21)		(0.6)
WCS Differential	6,000	July - December 2025		(19.30)		(3.8)
MSW Differential	500	Q3 2025	$	(6.59)	$	(0.2)
Total oil					**$**	**(2.5)**

	Notional Volume (mcf/d)	Remaining Term		Price (C$/mcf)		Fair value (millions)
Natural Gas						
AECO Swap	25,118	July 2025 - October 2025	$	2.24	$	2.7
AECO Swap	13,033	November 2025 - March 2026		3.55		0.3
AECO Collar	1,896	July 2025 - October 2025	$	2.11 - 2.64	$	0.2
Total natural gas					**$**	**3.2**
Total					**$**	**0.7**

Refer to the Business Environment section above for a full list of hedges currently outstanding including contracts that were entered into subsequent to June 30, 2025.

Based on commodity prices and contracts in place at June 30, 2025, the Company notes the following sensitivities:

- a $1.00 change in the price per barrel of liquids would change pre-tax unrealized risk management by $2.1 million; and
- a $0.10 change in the price per mcf of natural gas would change pre-tax unrealized risk management by $0.5 million.

The components of risk management within Income on the Consolidated Statements of Income are as follows:

	Three months ended June 30		Six months ended June 30	
(millions)	**2025**	2024	**2025**	2024
Realized				
Settlement of oil contracts loss	**$ (2.1)**	$ (0.4)	**$ (2.3)**	$ (0.4)
Settlement of natural gas contracts gain	**0.4**	4.4	**3.3**	8.2
Total realized risk management gain (loss)	**$ (1.7)**	$ 4.0	**$ 1.0**	$ 7.8
Unrealized				
Oil contracts gain (loss)	**$ 4.5**	$ 0.2	**$ (5.8)**	$ (0.1)
Natural gas contracts gain (loss)	**4.3**	2.8	**(0.6)**	(1.2)
Total unrealized risk management gain (loss)	**8.8**	3.0	**(6.4)**	(1.3)
Risk management gain (loss)	**$ 7.1**	$ 7.0	**$ (5.4)**	$ 6.5

Sensitivity Analysis

Estimated sensitivities to selected key assumptions on funds flow from operations for the 12 months subsequent to the date of this MD&A, including risk management contracts entered into to date, are based on forecasted results. The table below includes the impact of the Pembina Disposition.

		Impact on funds flow from operations (1)	
Change of:	Change	$ millions	$/share
WTI - Price per barrel of liquids	WTI US$1.00	8.1	0.12
WCS - Price per barrel of liquids	WCS US$1.00	5.3	0.08
Liquids production	1,000 bbl/day	17.9	0.26
Price per mcf of natural gas	AECO $0.10	1.0	0.01
Natural gas production	1 mmcf/day	0.8	0.01
Effective interest rate	1%	1.2	0.02
Exchange rate ($US per $CAD)	$ 0.01	3.4	0.05

(1) Non-GAAP financial measure or non-GAAP ratio. See "Non-GAAP and Other Financial Measures".

Contractual Obligations and Commitments

As at June 30, 2025, Obsidian Energy was committed to certain payments over the next five calendar years and thereafter as follows:

	2025	2026	2027	2028	2029	Thereafter	Total
Long-term debt (1)	**$ 48.4**	$ -	$ 177.8	$ -	$ -	$ -	$ 226.2
Transportation	**8.6**	15.7	12.9	12.0	12.1	5.7	67.0
Interest obligations	**10.2**	20.3	16.3	-	-	-	46.8
Lease liability	**0.8**	1.5	1.3	0.6	-	1.2	5.4
Decommissioning liability (2)	**14.9**	13.0	12.0	11.2	10.4	44.0	105.5
Total	**$ 82.9**	$ 50.5	$ 220.3	$ 23.8	$ 22.5	$ 50.9	$ 450.9

(1) The 2025 figure includes the current portion of our senior unsecured notes, which are expected to be subject to a Repurchase Offer pursuant to the terms of the notes. The 2027 figure includes our syndicated credit facility which has a term-out date of May 2027 and our senior unsecured notes not subject to the Repurchase Offer due in July 2027. Refer to the Financing section above for further details. Historically, the Company has successfully renewed our syndicated credit facility.
(2) These amounts represent the inflated, discounted future reclamation and abandonment costs that are expected to be incurred over the life of the Company's properties.

At June 30, 2025, the Company had an aggregate of $112.2 million in senior unsecured notes maturing in July 2027 and the revolving period of our syndicated credit facility was May 31, 2026, with a term out period to May 31, 2027. In the future, if the Company is unsuccessful in renewing or replacing the syndicated credit facility or obtaining alternate funding for some or all of the maturing amounts of the senior unsecured notes, it is possible that we could be required to seek other sources of financing, including other forms of debt or equity arrangements if available. Please see the Financing section of this MD&A for further details regarding our outstanding debt instruments.

The Company is involved in various litigation and claims in the normal course of business and records provisions for claims as required.

Equity Instruments

Common shares issued:	
As at June 30, 2025	67,708,673
Issuance under stock option and restricted and performance share unit plans	9,330
Repurchase and cancellation of common shares	(615,800)
As at July 29, 2025	67,102,203

Options outstanding:	
As at June 30, 2025	2,461,908
Exercised	(9,330)
Forfeited	(810)
As at July 29, 2025	2,451,768

RSUs outstanding:	
As at June 30, 2025	1,877,838
Forfeited	(84,838)
As at July 29, 2025	1,793,000

Supplemental Production Disclosure

Outlined below is production by product type for each area and in total for the three and six months ended June 30, 2025 and 2024.

	Three months ended June 30		Six months ended June 30	
Daily production (boe/d)	**2025**	2024	**2025**	2024
Cardium				
Light oil (bbl/d)	**5,568**	12,039	**8,684**	11,662
Heavy oil (bbl/d)	**24**	67	**49**	57
NGLs (bbl/d)	**2,107**	3,099	**2,546**	2,892
Natural gas (mmcf/d)	**41**	63	**50**	62
Total production (boe/d)	**14,462**	25,702	**19,687**	24,880
Peace River				
Light oil (bbl/d)	**11**	-	**6**	-
Heavy oil (bbl/d)	**11,910**	6,838	**11,303**	6,701
NGLs (bbl/d)	**16**	9	**15**	11
Natural gas (mmcf/d)	**5**	2	**5**	3
Total production (boe/d)	**12,827**	7,222	**12,221**	7,254
Viking				
Light oil (bbl/d)	**663**	1,685	**743**	1,700
Heavy oil (bbl/d)	**79**	87	**85**	91
NGLs (bbl/d)	**41**	59	**43**	60
Natural gas (mmcf/d)	**3**	4	**3**	4
Total production (boe/d)	**1,338**	2,538	**1,428**	2,521
Legacy				
Light oil (bbl/d)	**72**	58	**70**	68
Heavy oil (bbl/d)	**28**	34	**30**	38
NGLs (bbl/d)	**25**	26	**24**	26
Natural gas (mmcf/d)	**1**	2	**2**	1
Total production (boe/d)	**316**	311	**317**	351
Total				
Light oil (bbl/d)	**6,314**	13,782	**9,503**	13,430
Heavy oil (bbl/d)	**12,041**	7,026	**11,467**	6,887
NGLs (bbl/d)	**2,189**	3,193	**2,628**	2,989
Natural gas (mmcf/d)	**50**	71	**60**	70
Total production (boe/d)	**28,943**	35,773	**33,653**	35,006

Reconciliation of Cash flow from Operating Activities to Funds flow from Operations

Three months ended	**Jun. 30 2025**	Mar. 31 2025	Dec. 31 2024	Sep. 30 2024	Jun. 30 2024	Mar. 31 2024	Dec. 31 2023	Sep. 30 2023
Cash flow from operating activities	**$ 55.2**	$ 96.7	$ 115.0	$ 110.3	$ 77.9	$ 58.7	$ 117.7	$ 95.3
Change in non-cash working capital	**4.3**	(5.8)	(13.5)	6.1	29.7	13.4	(30.3)	(3.6)
Decommissioning expenditures	**4.0**	6.6	3.5	6.3	4.0	10.1	7.7	5.3
Onerous office lease settlements	**-**	0.7	2.3	2.2	2.2	2.3	2.3	2.2
Settlement of restricted share units	**-**	-	-	-	-	-	0.1	0.1
Deferred financing costs	**(0.6)**	(0.4)	(0.5)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)
Restructuring	**0.7**	0.1	-	-	-	-	-	-
Transaction costs	**2.2**	2.2	-	-	1.4	-	-	-
Other expenses	**-**	-	0.9	0.4	0.6	0.5	0.1	0.2
Funds flow from operations	**$ 65.8**	$ 100.1	$ 107.7	$ 124.7	$ 115.2	$ 84.4	$ 97.0	$ 98.9

Changes in Internal Control Over Financial Reporting (“ICFR”)

Obsidian Energy’s senior management has evaluated whether there were any changes in the Company's ICFR that occurred during the period beginning on April 1, 2025 and ending on June 30, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. No changes to the Company’s ICFR were made during the quarter.

Off-Balance-Sheet Financing

Obsidian Energy has off-balance-sheet financing arrangements consisting of operating leases. The operating lease payments are summarized in the Contractual Obligations and Commitments section.

Non-GAAP and Other Financial Measures

Throughout this MD&A and in other materials disclosed by the Company, we employ 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 by IFRS and therefore may not be comparable to similar measures provided by other issuers. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss) and cash flow from operating activities, as indicators of our performance.

Non-GAAP Financial Measures

“Free cash flow” is funds flow from operations less both capital and decommissioning expenditures and the Company believes it is a useful measure to determine and indicate the funding available to Obsidian Energy for investing and financing activities, including the repayment of debt, reallocation to existing areas of operation, deployment into new ventures and return of capital to shareholders. See “Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow” above for a reconciliation of free cash flow to cash flow from operating activities, being our nearest measure prescribed by IFRS.

“Funds flow from operations” is cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures, onerous office lease settlements, settlement of RSUs, the effects of financing related transactions from foreign exchange contracts and debt repayments, restructuring, transaction costs and certain other expenses and is representative of cash related to continuing operations. Funds flow from operations is used to assess the Company’s ability to fund our planned capital programs. See “Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow” and "Reconciliation of Cash flow from operating activities to Funds flow from operations" above for reconciliations of funds flow from operations to cash flow from operating activities, being our nearest measure prescribed by IFRS.

“Gross revenues” are production revenues including realized risk management gains and losses on commodity contracts and adjusted for commodities purchased from third parties and sales of commodities purchased from third parties and is used to assess the cash realizations on commodity sales. See “Results of Operations – Production Revenues” above for a reconciliation of gross revenues to production revenues, being our nearest measure prescribed by IFRS.

"Sales" are production revenues plus sales of commodities purchased from third parties less commodities purchased from third parties and is used to assess the cash realizations on commodity sales before realized risk management gains and losses. See "Results of Operations – Production Revenues" above for a reconciliation of gross revenues and sales to production revenues, being our nearest measure prescribed by IFRS.

"Net debt" is the total of long-term debt and working capital deficiency and is used by the Company to assess our liquidity. See "Liquidity and Capital Resources – Net Debt" above for a reconciliation of net debt to long-term debt, being our nearest measure prescribed by IFRS.

"Net operating costs" are calculated by deducting processing income, road use recoveries and realized gains and losses on power risk management contracts from operating costs and is used to assess the Company's cost position. Processing fees are primarily generated by processing third party volumes at the Company's facilities. In situations where the Company has excess capacity at a facility, it may agree with third parties to process their volumes to reduce the cost of operating/owning the facility. Road use recoveries are a cost recovery for the Company as we operate and maintain roads that are also used by third parties. Realized gains and losses on power risk management contracts occur upon settlement of our contracts. See "Results of Operations – Expenses – Operating" above for a reconciliation of net operating costs to operating costs, being our nearest measure prescribed by IFRS.

"Netback" is production revenues plus sales of commodities purchased from third parties less commodities purchased from third parties (sales), less royalties, net operating costs, transportation expenses and realized risk management gains and losses, and is used in capital allocation decisions and to economically rank projects. See "Results of Operations – Netbacks" above for a reconciliation of netbacks to sales and "Results of Operations – Production Revenues" above for a reconciliation of sales to production revenues, being our nearest measure prescribed by IFRS.

Non-GAAP Ratios

"Funds flow from operations – basic per share" is comprised of funds flow from operations divided by basic weighted average common shares outstanding. Funds flow from operations is a non-GAAP financial measure. See "Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow" and "Reconciliation of Cash flow from operating activities to Funds flow from operations" above.

"Funds flow from operations – diluted per share" is comprised of funds flow from operations divided by diluted weighted average common shares outstanding. Funds flow from operations is a non-GAAP financial measure. See "Cash flow from Operating Activities, Funds Flow from Operations and Free Cash Flow" and "Reconciliation of Cash flow from operating activities to Funds flow from operations" above.

"Net operating costs per bbl", "Net operating costs per mcf" and "Net operating costs per boe" are net operating costs divided by weighted average daily production on a per bbl, per mcf or per boe basis, as applicable. Net operating costs is a non-GAAP financial measure. See "Results of Operations – Expenses – Operating" above.

"Netback per bbl", "Netback per mcf" and "Netback per boe" are netbacks divided by weighted average daily production on a per bbl, per mcf or per boe basis, as applicable. Management believes that netback per boe is a key industry performance measure of operational efficiency and provides investors with information that is also commonly presented by other oil and natural gas producers. Netback is a non-GAAP financial measure. See "Results of Operations – Netbacks" above.

"Sales per boe" is sales divided by weighted average daily production on a per boe basis. Sales is a non-GAAP financial measure. See "Results of Operations – Production Revenues" above.

Supplementary Financial Measures

Average sales prices for light oil, heavy oil, NGLs, total liquids and natural gas are supplementary financial measures calculated by dividing each of these components of production revenues by their respective production volumes for the periods.

"Cash flow from operating activities – basic per share" is comprised of cash flow from operating activities, as determined in accordance with IFRS, divided by basic weighted average common shares outstanding.

"Cash flow from operating activities – diluted per share" is comprised of cash flow from operating activities, as determined in accordance with IFRS, divided by diluted weighted average common shares outstanding.

"G&A gross – per boe" is comprised of general and administrative expenses on a gross basis, as determined in accordance with IFRS, divided by boe for the period.

"G&A net – per boe" is comprised of general and administrative expenses on a net basis, as determined in accordance with IFRS, divided by boe for the period.

Oil and Natural Gas Information

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is misleading as an indication of value.

Abbreviations

Oil		Natural Gas	
bbl	barrel or barrels	mcf	thousand cubic feet
bbl/d	barrels per day	mcf/d	thousand cubic feet per day
boe	barrel of oil equivalent	mmcf	million cubic feet
boe/d	barrels of oil equivalent per day	mmcf/d	million cubic feet per day
MSW	Mixed Sweet Blend	mmbtu	Million British thermal unit
WTI	West Texas Intermediate	AECO	Alberta benchmark price for natural gas
WCS	Western Canadian Select	NGL	natural gas liquids
		LNG	liquefied natural gas
		NYMEX	New York Mercantile Exchange price for natural gas

References to Q1, Q2, Q3 and Q4 are to the three-month periods ended March 31, June 30, September 30 and December 31, respectively.

Forward-Looking Statements

Certain statements contained in this document constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. In particular, this document contains forward-looking statements pertaining to, without limitation, the following: the expected growth in production of our Peace River assets through further development and delineation of existing and establishing new fields in such areas; the continued development of both the Bluesky and Clearwater heavy oil formations; the expectation that our Willesden Green and Viking light oil assets will continue to generate stable production and free cash flow to help fund growth in our Peace River assets; the Company's intention to generate acceptable returns and maintain our financial strength; monetization options for our InPlay Share position including the non-binding offer received and ongoing negotiations in connection therewith; our expectations for the NCIB in 2025; potential US imposed tariffs and the anticipated impact on the global economy and commodity markets; anticipated increased output from OPEC and the expected impacts on commodity prices; our environmental remediation efforts; our intention to monitor our operations for environmental impacts and allocate capital to reclamation and other activities in the areas we operate; our intention to follow the Alberta Energy Regulator guidance under Directive 088; our hedges; our intention to use multiple sales points in the Peace River area and the anticipated benefits in connection therewith; our expectations in connection with taxable profits and the Company's ability to utilize its remaining deferred tax asset balance; the terms and conditions under our syndicated credit facility and senior unsecured notes and our expectations if the Company is unsuccessful in renewing or replacing them in the future; our involvement with various litigation in the normal course of business and the anticipated effects thereof; how we plan to manage our debt portfolio; all information disclosed under "Sensitivity Analysis"; our future payment obligations as disclosed under "Contractual Obligations and Commitments"; that management contemplates both operating and financial risks and takes action as appropriate to limit the Company's exposure to certain risks; and that management maintains close relationships with the Company's lenders and agents to monitor credit market developments, and these actions and plans aim to increase the likelihood of maintaining the Company's financial flexibility and capital program and the anticipated benefits in connection therewith.

With respect to forward-looking statements contained in this document, the Company has made assumptions regarding, among other things: the duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; that the Company does not dispose of or acquire material producing properties or royalties or other interests therein (except as disclosed herein, including with respect to our InPlay Shares); that regional and/or global health related events will not have any adverse impact on energy demand and commodity prices in the future; global energy policies going forward, including the continued ability and willingness of members of OPEC and other nations to agree on and adhere to production quotas from time to time; our ability to qualify for (or continue to qualify for) new or existing government programs, and obtain financial assistance therefrom, and the impact of those programs on our financial condition; our ability to execute our plans as described herein and in our other disclosure documents, and the impact that the successful execution of such plans will have on our Company and our stakeholders, including our ability to return capital to shareholders and/or further reduce debt levels; future capital expenditure and decommissioning expenditure levels; expectations and assumptions concerning applicable laws and regulations, including with respect to environmental, safety and tax matters; future operating costs and G&A costs and the impact of inflation thereon; future oil, natural gas liquids and natural gas prices and differentials between light, medium and heavy oil prices and Canadian, WTI and world oil and natural gas prices; future hedging activities; future oil, natural gas liquids and natural gas production levels; future exchange rates, interest rates and inflation rates; future debt levels; our ability to execute our capital programs as planned without significant adverse impacts from various factors beyond our control, including extreme weather events such as wild fires, flooding and drought, infrastructure access (including the potential for blockades or other activism) and delays in obtaining regulatory approvals and third party consents; the ability of the Company's contractual counterparties to perform their contractual obligations; our ability to obtain equipment in a timely manner to carry out development activities and the costs thereof; our ability to market our oil and natural gas successfully to current and new customers; our ability to obtain financing on acceptable terms, including our ability (if necessary) to extend the revolving period and term out period of our credit facility, our ability to maintain the existing borrowing base under our credit facility, our ability (if necessary) to replace our syndicated bank facility and our ability (if necessary) to finance the repayment of our senior unsecured notes on maturity or pursuant to the terms of the underlying agreement; the accuracy of our estimated reserve volumes; and our ability to add production and reserves through our development and exploitation activities.

The future acquisition by the Company of the Company's common shares pursuant to its share buyback program (including through its NCIB), if any, and the level thereof is uncertain. Any decision to acquire common shares of the Company pursuant to the share buyback program will be subject to the discretion of the board of directors of the Company and may depend on a variety of factors, including, without limitation, the Company's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Company under applicable corporate law. There can be no assurance of the number of common shares of the Company that the Company will acquire pursuant to its share buyback program, if any, in the future.

Although the Company believes that the expectations reflected in the forward-looking statements contained in this document, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this document, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the forward-looking statements contained herein will not be correct, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: the risk that (i) the tariffs that are currently in effect on goods exported from or imported into Canada continue in effect for an extended period of time, the tariffs that have been threatened are implemented, that tariffs that are currently suspended are reactivated, the rate or scope of tariffs are increased, or new tariffs are imposed, including on oil and natural gas, (ii) the U.S. and/or Canada imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas, and (iii) the tariffs imposed or threatened to be imposed by the U.S. on other countries and retaliatory tariffs imposed or threatened to be imposed by other countries on the U.S., will trigger a broader global trade war which could have a material adverse effect on the Canadian, U.S. and global economies, and by extension the Canadian oil and natural gas industry and the Company, including by decreasing demand for (and the price of) oil and natural gas, disrupting supply chains, increasing costs, causing volatility in global financial markets, and limiting access to financing; the possibility that we change our budgets (including our capital expenditure budgets) in response to internal and external factors, including those described herein; the possibility that the Company will not be able to continue to successfully execute our business plans and strategies in part or in full, and the possibility that some or all of the benefits that the Company anticipates will accrue to our Company and our stakeholders as a result of the successful execution of such plans and strategies do not materialize (such as our inability to return capital to shareholders and/or reduce debt levels to the extent anticipated or at all); the possibility that the Company ceases to qualify for, or does not qualify for, one or more existing or new government assistance programs, that the impact of such programs falls below our expectations, that the benefits under one or more of such programs is decreased, or that one or more of such programs is discontinued; the impact on energy demand and commodity prices of regional and/or global health related events and the responses of governments and the public thereto, including the risk that the amount of energy demand destruction and/or the length of the decreased demand exceeds our expectations; the risk that there is another significant decrease in the valuation of oil and natural gas companies and their securities and in confidence in the oil and natural gas industry generally, whether caused by regional and/or global health related events, the worldwide transition towards less reliance on fossil fuels and/or other factors; the risk that the financial capacity of the Company's contractual counterparties is adversely affected and potentially their ability to perform their contractual obligations; the possibility that the revolving period and/or term out period of our credit facility and the maturity date of our senior unsecured notes is not extended (if necessary), that the borrowing base under our credit facility is reduced, that the Company is unable to renew or refinance our credit facilities on acceptable terms or at all and/or finance the repayment of our senior unsecured notes when they mature on acceptable terms or at all and/or obtain new debt and/or equity financing to replace our credit facilities and/or senior unsecured notes or to fund other activities; the possibility that we are unable to complete one or more Repurchase Offers when otherwise required to do so; the possibility that we are forced to shut-in production, whether due to commodity prices decreasing, extreme weather events such as wild fires, inability to access our properties due to blockades or other activism, or other factors; the risk that OPEC and other nations fail to agree on and/or adhere to production quotas from time to time that are sufficient to balance supply and demand fundamentals for oil; general economic and political conditions in Canada, the U.S. and globally, and in particular, the effect that those conditions have on commodity prices and our access to capital; industry conditions, including fluctuations in the price of oil, natural gas liquids and natural gas, price differentials for oil and natural gas produced in Canada as compared to other markets, and transportation restrictions, including pipeline and railway capacity constraints; fluctuations in foreign exchange, including the impact of the Canadian/U.S. dollar exchange rate on our revenues and expenses; fluctuations in interest rates, including the effects of interest rates on our borrowing costs and on economic activity, and including the risk that elevated interest rates cause or contribute to the onset of a recession; the risk that our costs increase due to inflation, supply chain disruptions, scarcity of labour and/or other factors, adversely affecting our profitability; unanticipated operating events or environmental events that can reduce production or cause production to be shut-in or delayed (including extreme cold during winter months, wild fires, flooding and droughts (which could limit our access to the water we require for our operations)); the risk that wars and other armed conflicts adversely affect world economies and the demand for oil and natural gas, including the ongoing war between Russian and Ukraine and/or hostilities in the Middle East; the possibility that fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to hydrocarbons, government mandates requiring the sale of electric vehicles and/or electrification of the power grid, and technological advances in fuel economy and renewable energy generation systems could permanently reduce the demand for oil and natural gas and/or permanently impair the Company's ability to obtain financing and/or insurance on acceptable terms or at all, and the possibility that some or all of these risks are heightened as a result of the response of governments, financial institutions and consumers to a regional and/or global health related event and/or the influence of public opinion and/or special interest groups; and the other factors described under "Risk Factors" in our Annual Information Form and described in our public filings, available in Canada at www.sedarplus.ca and in the United States at www.sec.gov. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The forward-looking statements contained in this document speak only as of the date of this document. Except as expressly required by applicable securities laws, the Company does not undertake any obligation to publicly update any forward-looking statements. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Additional Information

Additional information relating to Obsidian Energy, including Obsidian Energy’s Annual Information Form, is available on the Company’s website at www.obsidianenergy.com, on SEDAR+ at www.sedarplus.ca and on EDGAR at www.sec.gov.