MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and six months ended June 30, 2026

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, 2026 and the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2025. The date of this MD&A is July 29, 2026. 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, adjusted 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 2026**	Mar. 31 2026	Dec. 31 2025	Sep. 30 2025	Jun. 30 2025	Mar. 31 2025	Dec. 31 2024	Sep. 30 2024
Production revenues	**$ 197.7**	$ 148.7	$ 123.8	$ 128.7	$ 136.3	$ 211.0	$ 213.6	$ 218.2
Cash flow from operating activities	**38.2**	40.0	42.6	45.4	55.2	96.7	115.0	110.3
Basic per share [(1)]	**0.57**	0.59	0.63	0.68	0.79	1.32	1.55	1.45
Diluted per share [(1)]	**0.55**	0.59	0.62	0.66	0.75	1.27	1.49	1.40
Funds flow from operations [(2)]	**67.8**	61.0	56.6	49.7	65.8	100.1	107.7	124.7
Basic per share [(3)]	**1.02**	0.91	0.84	0.74	0.94	1.36	1.45	1.64
Diluted per share [(3)]	**0.98**	0.91	0.82	0.72	0.90	1.31	1.39	1.58
Adjusted funds flow from operations [(2)]	**73.6**	59.0	56.3	55.2	63.2	100.9	109.0	117.8
Basic per share [(3)]	**1.10**	0.88	0.84	0.82	0.90	1.37	1.47	1.55
Diluted per share [(3)]	**1.06**	0.88	0.81	0.80	0.86	1.32	1.47	1.49
Net income (loss)	**42.0**	(18.7)	(12.3)	16.8	15.3	15.4	(284.8)	33.2
Basic per share	**0.63**	(0.28)	(0.18)	0.25	0.22	0.21	(3.83)	0.44
Diluted per share	**$ 0.61**	$ (0.28)	$ (0.18)	$ 0.24	$ 0.21	$ 0.20	$ (3.83)	$ 0.42
Production								
Light oil (bbl/d)	**6,696**	6,189	5,443	4,979	6,314	12,727	13,271	13,722
Heavy oil (bbl/d)	**10,757**	12,390	12,782	12,586	12,041	10,887	11,621	10,624
NGLs (bbl/d)	**2,237**	2,088	2,037	1,955	2,189	3,072	3,176	3,148
Natural gas (mmcf/d)	**51**	48	46	47	50	70	72	73
Total (boe/d)[(4)]	**28,200**	28,733	27,971	27,316	28,943	38,416	40,119	39,714

(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, Adjusted Funds Flow from Operations and Free Cash Flow

	Three months ended June 30		Six months ended June 30	
(millions, except per share amounts)	**2026**	2025	**2026**	2025
Cash flow from operating activities	**$ 38.2**	$ 55.2	**$ 78.2**	$ 151.9
Change in non-cash working capital	**25.9**	4.3	**13.8**	(1.5)
Decommissioning expenditures	**1.3**	4.0	**3.0**	10.6
Equity forward contracts	**1.2**	-	**32.4**	-
Onerous office lease settlements	**-**	-	**-**	0.7
Deferred financing costs	**(0.5)**	(0.6)	**(0.9)**	(1.0)
Restructuring	**0.1**	0.7	**0.3**	0.8
Transaction costs	**1.2**	2.2	**1.2**	4.4
Other expenses	**0.4**	-	**0.8**	-
Funds flow from operations (1)	**67.8**	65.8	**128.8**	165.9
Deferred share units	**(3.2)**	(1.5)	**7.1**	(1.2)
Performance share units	**0.1**	(1.1)	**7.6**	(0.6)
Equity forward contracts loss (gain)	**8.9**	-	**(10.9)**	-
Adjusted funds flow from operations (1)	**$ 73.6**	$ 63.2	**$ 132.6**	$ 164.1
Capital expenditures	**(39.1)**	(40.2)	**(118.8)**	(168.6)
Decommissioning expenditures	**(1.3)**	(4.0)	**(3.0)**	(10.6)
Free Cash Flow (1)	**$ 33.2**	$ 19.0	**$ 10.8**	$ (15.1)
Per share – funds flow from operations (2)				
Basic per share	**$ 1.02**	$ 0.94	**$ 1.92**	$ 2.31
Diluted per share	**$ 0.98**	$ 0.90	**$ 1.86**	$ 2.23
Per share – adjusted funds flow from operations (2)				
Basic per share	**$ 1.10**	$ 0.90	**$ 1.98**	$ 2.29
Diluted per share	**$ 1.06**	$ 0.86	**$ 1.91**	$ 2.21

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

Funds flow from operations and adjusted funds flow from operations in Q2 2026 increased from Q2 2025, primarily due to higher realized oil prices, which was partially offset by higher realized risk management losses. Cash flow from operating activities decreased from Q2 2025 due to the purchase of prepaid equity forward contracts to mitigate share-based compensation exposure and higher realized risk management losses.

For the first six months of 2026, cash flow from operating activities, funds flow from operations and adjusted funds flow from operations decreased compared to the same period in 2025, primarily due to lower production volumes resulting from the disposition of our operated Pembina assets (the "Pembina Disposition") at the beginning of Q2 2025, which was partially offset by higher oil prices.

Belly River Acquisition

On June 30, 2026, the Company closed an asset acquisition to acquire high-return Belly River light oil assets in the Wilson Creek area of Willesden Green (the “Belly River Acquisition”), which included approximately 2,500 boe/d of Belly River production (based on May 2026 production) and 35 net sections of land. Total consideration paid was $98.0 million, inclusive of closing adjustments. This acquisition complements our existing lands, adding a number of drilling locations and further supporting our growth strategy in the Willesden Green area.

In addition, a contingent value payment ("CVP") of up to $7.0 million may be payable in quarterly installments of up to $1.75 million from Q3 2026 through to Q2 2027, subject to a range of average West Texas Intermediate ("WTI") oil prices in the applicable quarter. At June 30, 2026, based on forecasted WTI prices, no value was ascribed to the CVPs.

Pembina Disposition

On April 7, 2025, the Company closed the Pembina Disposition to InPlay Oil Corp. ("InPlay") of our operated Pembina (Cardium) assets (the "Pembina Assets"). Total consideration for the transaction included $208.3 million of cash (inclusive of final closing adjustments), 9,139,784 common shares of InPlay, after giving effect to InPlay's consolidation of its common shares on a one for six basis effective April 14, 2025, ("InPlay Shares") and a $14.7 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 retained. As part of the transaction, InPlay assumed all assets and liabilities associated with the Pembina Assets, including the Company's decommissioning liabilities.

In August 2025, the Company closed the sale of all of our InPlay Shares to a third party, for proceeds of $91.4 million, resulting in a $15.2 million gain.

This transaction further strengthened our balance sheet while reducing our decommissioning liabilities by over 50 percent, with the cash proceeds from the transaction used to initially pay down outstanding debt on our syndicated credit facility at closing and subsequently used to accelerate our share buyback program.

Business Strategy

The Company has a high-quality, balanced portfolio of heavy and light oil assets with significant development opportunities that support our long-term growth strategy. In Peace River, over the past few years, we have more than doubled production through a focused development program. With a land base of more than 830 net sections, we expect to continue growing Clearwater and Bluesky production through the development and delineation of existing and new fields. We also continue to advance our enhanced oil recovery strategy through waterflood initiatives and are encouraged by the results to date. Building on this success, we have expanded these initiatives in the first half of 2026 and expect to further advance our enhanced oil recovery program in the second half of the year.

In Willesden Green, we also expect to grow our light oil production through ongoing development. The Company began developing the Belly River formation in 2025 and expanded development activity in the formation in the first half of 2026, supported by strong results and expanded infrastructure. Our recent Belly River Acquisition in the area further strengthens this opportunity, and we expect to accelerate growth by leveraging our larger production base and expanded operational footprint. The pace of future development across our heavy and light oil assets will depend on the macroeconomic environment, including commodity prices and service costs, as we seek to generate attractive returns while maintaining the Company's financial strength.

Alongside investing in high-return development opportunities, we remain committed to disciplined capital allocation and enhancing shareholder returns. In 2023, we launched our return of capital initiative through our normal course issuer bid ("NCIB"). The NCIB has enhanced shareholder returns through a disciplined focus on per-share growth. Repurchases under the NCIB are subject to maintaining at least $65 million of liquidity and complying with the terms of our current credit facilities. Since launching the NCIB in 2023, we have repurchased and cancelled approximately 18.9 million common shares, representing approximately 23 percent of the shares outstanding when the program commenced, for total consideration of $164.6 million.

In addition to our NCIB, we have implemented capital management initiatives to support shareholder value and manage financial risk. In 2025, the Company began mitigating its share-based compensation exposure by entering into prepaid equity forward contracts. To date, the Company has entered into prepaid equity forward contracts covering a total of 5,210,000 shares at a weighted average share price of $9.65. The contracts expire between 2028 and 2029; however, the Company may monetize them at its discretion prior to expiry.

Beyond investing in our asset base and returning capital to shareholders, we remain committed to responsible environmental stewardship. We continued with our environmental remediation efforts in the first half of 2026 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 2026	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024
Benchmark prices								
WTI oil ($US/bbl)	**$ 92.79**	$ 71.93	$ 59.14	$ 64.93	$ 63.74	$ 71.42	$ 70.27	$ 75.09
Edm mixed sweet par price (CAD$/bbl)	**131.53**	93.39	76.30	86.57	84.04	95.00	94.39	97.60
Western Canada Select (CAD$/bbl)	**107.89**	79.19	66.65	75.28	73.89	84.04	80.67	83.80
NYMEX Henry Hub ($US/mmbtu)	**2.90**	5.04	3.55	3.07	3.44	3.65	2.79	2.16
AECO 5A Index (CAD$/mcf)	**1.63**	2.01	2.23	0.60	1.69	2.17	1.48	0.69
Foreign exchange rate (US/CAD)	**1.38**	1.37	1.39	1.38	1.38	1.43	1.40	1.37
Benchmark differentials								
WTI - Edm Light Sweet ($US/bbl)	**2.52**	(3.76)	(4.25)	(2.20)	(2.84)	(4.98)	(2.42)	(3.35)
WTI - Western Canadian Select Heavy ($US/bbl)	**(14.61)**	(14.13)	(11.19)	(10.38)	(10.20)	(12.65)	(12.54)	(13.51)
Average sales price (1) (2)								
Light oil (CAD$/bbl)	**132.25**	97.23	75.30	86.67	91.09	99.46	96.95	100.09
Heavy oil (CAD$/bbl)	**99.28**	69.40	59.10	67.93	61.27	70.14	67.70	73.73
NGLs (CAD$/bbl)	**62.00**	37.11	35.33	36.44	39.42	53.49	44.27	48.92
Total liquids (CAD$/bbl)	**106.25**	74.47	61.07	69.56	68.11	82.21	78.88	84.04
Natural gas (CAD$/mcf)	**$ 1.65**	$ 2.38	$ 2.38	$ 0.91	$ 2.00	$ 2.18	$ 1.53	$ 0.86

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

Oil

WTI averaged US$92.79/bbl during Q2 2026. Prices began the quarter at approximately US$98.00/bbl in April, peaked above US$110.00/bbl in early April, before declining to approximately US$70.00/bbl range in June. The decline was primarily driven by the ceasefire agreement between the U.S. and Iran, which eased concerns over supply disruptions through the Strait of Hormuz and allowed additional oil supply to return to the global market.

WCS differentials remained relatively stable during Q2 2026, averaging US$14.61/bbl compared to US$14.13/bbl in Q1 2026. In contrast, MSW traded at an average premium of US$2.52/bbl to WTI whereas it usually trades at a discount. The ongoing conflict in the Middle East kept significant light oil production offline, supporting demand for light oil from Western Canada and contributing to the premium.

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

Type	**Volume (bbls/d)**	**Remaining Term**	**Price (US$/bbl)**
WTI Swap	10,982	July 2026	$ 76.86
WTI Swap	2,450	August 2026	81.40
WTI Swap	1,500	September 2026	82.46
WTI Collar	7,500	August 2026	79.50 - 87.66
WTI Collar	1,350	September 2026	$ 80.00 - 87.42

Natural Gas

The average NYMEX futures price was US$2.90/MMBtu during Q2 2026. In Alberta, AECO 5A prices averaged CAD$1.63/mcf in Q2 2026, down from CAD$2.01/mcf in Q1. The decline in Alberta natural gas prices was driven by strong natural gas supply and seasonally lower demand during the shoulder season.

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	35,077	July 2026 - October 2026	$	2.69
AECO Swap	9,479	November 2026 - March 2027	$	2.95

Foreign Exchange Forward Contracts

The Company enters into foreign exchange forward contracts to mitigate the risk of changes in the $US/$CAD exchange rate on oil sales that reference $US benchmark prices and commodity hedging contracts that are settled in $US. The Company currently has the following contracts in place on a weighted average basis:

Type		Notional Amount ($ millions)	Remaining Term		Price (C$)
FX forward contract	$	21.3	July 2026	$	1.3729
FX forward contract		21.3	August 2026		1.3739
FX forward contract	$	11.7	September 2026	$	1.3866

Prepaid Equity Forward Contracts

In Q3 2025, the Company began entering into prepaid equity forward contracts in respect of our common shares to mitigate the equity price risk associated with our share-based compensation plans. The Company currently has the following contracts in place on a weighted average basis:

Type	Share Volume	Remaining Term [1]		Price (C$)
Equity Forward Contract	720,000	September 2028	$	8.89
Equity Forward Contract	1,300,000	October 2028		8.72
Equity Forward Contract	550,000	November 2028		8.43
Equity Forward Contract	715,000	December 2028		8.31
Equity Forward Contract	450,000	January 2029		8.76
Equity Forward Contract	680,000	February 2029		10.18
Equity Forward Contract	710,000	April 2029		13.82
Equity Forward Contract	85,000	June 2029	$	15.10
Total share volume	5,210,000	Weighted average price	$	9.65

(1) The Company can settle the contract, or a portion of the contract, at any time.

RESULTS OF OPERATIONS

Average Sales Prices [1]

	Three months ended June 30			Six months ended June 30		
	2026	2025	% change	**2026**	2025	% change
Light oil (per bbl)	**$ 132.25**	$ 91.09	45	**$ 115.52**	$ 96.66	20
Heavy oil (per bbl)	**99.28**	61.27	62	**83.37**	65.46	27
NGL (per bbl)	**62.00**	39.42	57	**50.05**	47.60	5
Total liquids (per bbl)	**106.25**	68.11	56	**90.07**	76.04	18
Realized risk management loss (per bbl)	**(22.65)**	(1.11)	1,941	**(15.87)**	(0.54)	2,839
Total liquids, net (per bbl)	**83.60**	67.00	25	**74.20**	75.50	(2)
Natural gas (per mcf)	**1.65**	2.00	(18)	**2.00**	2.11	(5)
Realized risk management gain (per mcf)	**0.82**	0.08	925	**0.64**	0.30	113
Natural gas net (per mcf)	**2.47**	2.08	19	**2.64**	2.41	10
Weighted average (per boe)	**77.17**	51.83	49	**67.33**	57.09	18
Realized risk management gain (loss) (per boe)	**(14.34)**	(0.64)	2,141	**(10.13)**	0.17	N/A
Weighted average net (per boe)	**$ 62.83**	$ 51.19	23	**$ 57.20**	$ 57.26	-

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

Production

	Three months ended June 30			Six months ended June 30		
Daily production	**2026**	2025	% change	**2026**	2025	% change
Light oil (bbl/d)	**6,696**	6,314	6	**6,444**	9,503	(32)
Heavy oil (bbl/d)	**10,757**	12,041	(11)	**11,569**	11,467	1
NGL (bbl/d)	**2,237**	2,189	2	**2,163**	2,628	(18)
Natural gas (mmcf/d)	**51**	50	2	**50**	60	(17)
Total production (boe/d)	**28,200**	28,943	(3)	**28,465**	33,653	(15)

Production decreased in Q2 2026 compared to the corresponding period in 2025, primarily due to a reduced capital program in the second half of 2025 and a prolonged spring break-up and extremely wet conditions in Q2 2026 resulted in delays to certain tie-in and optimization activities. For the first six months of 2026 versus 2025, production decreased primarily due to the Pembina Disposition, which closed at the beginning of Q2 2025. Prior to the disposition, the Pembina Assets produced approximately 11,000 boe/d in Q1 2025, consisting of light oil, NGLs and natural gas.

In the first six months of 2026, we drilled 28 (25.8 net) wells, including injector wells and non-operated activity, and a total of 29 (23.5 net) wells 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)	**2026**	2025	% change	**2026**	2025	% change
Willesden Green/PCU #11	**15,393**	14,462	6	**14,831**	19,687 (2)	(25)
Peace River	**11,734**	12,827	(9)	**12,498**	12,221	2
Viking	**778**	1,338	(42)	**849**	1,428	(41)
Legacy	**295**	316	(7)	**287**	317	(9)
Total	**28,200**	28,943	(3)	**28,465**	33,653	(15)

(1) Refer to "Supplemental Production Disclosure" for details by product type.
(2) Includes production from the Pembina Assets of approximately 11,000 boe/d.

Netbacks

	Three months ended June 30		Six months ended June 30	
(per boe)	**2026**	2025	**2026**	2025
Netback:				
Sales price (1) (3)	**$ 77.17**	$ 51.83	**$ 67.33**	$ 57.09
Risk management gain (loss) (2)	**(14.34)**	(0.64)	**(10.13)**	0.17
Royalties	**(9.90)**	(6.03)	**(7.44)**	(7.27)
Transportation	**(5.22)**	(4.49)	**(5.24)**	(4.69)
Net operating costs (3)	**(14.49)**	(13.54)	**(14.54)**	(14.78)
Netback (3)	**$ 33.22**	$ 27.13	**$ 29.98**	$ 30.52

	(boe/d)	(boe/d)	**(boe/d)**	(boe/d)
Production	**28,200**	28,943	**28,465**	33,653

(1) Includes the impact of commodities purchased from and sold to third parties of $0.3 million for Q2 2026 (2025 – $0.2 million) and $0.5 million for the first six months of 2026 (2025 – $0.5 million). 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 per boe increased in Q2 2026 compared to Q2 2025, primarily due to higher realized oil prices, partially offset by increased royalties and realized risk management losses on oil hedges. For the first six months of 2026, the Company's netback per boe decreased slightly from the corresponding period in 2025, primarily because the positive impact of higher realized oil prices was more than offset by higher realized risk management losses, royalties, and transportation costs.

(millions)	Three months ended June 30 2026	2025	Six months ended June 30 2026	2025
Netback:				
Sales (1) (3)	**$ 198.0**	$ 136.5	**$ 346.9**	$ 347.8
Risk management gain (loss) (2)	**(36.7)**	(1.7)	**(52.2)**	1.0
Royalties	**(25.4)**	(15.9)	**(38.3)**	(44.3)
Transportation	**(13.4)**	(11.8)	**(27.0)**	(28.6)
Net operating costs (3)	**(37.3)**	(35.6)	**(74.9)**	(90.0)
Netback (3)	**$ 85.2**	$ 71.5	**$ 154.5**	$ 185.9

(1) Includes the impact of commodities purchased from and sold to third parties of $0.3 million for Q2 2026 (2025 – $0.2 million) and $0.5 million for the first six months of 2026 (2025 – $0.5 million). 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" and see "Expenses - Operating" for a reconciliation of net operating costs to operating costs.

Production Revenues

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

(millions)	Three months ended June 30 2026	2025	Six months ended June 30 2026	2025
Production revenues	**$ 197.7**	$ 136.3	**$ 346.4**	$ 347.3
Sales of commodities purchased from third parties	**1.8**	1.3	**2.4**	3.3
Less: Commodities purchased from third parties	**(1.5)**	(1.1)	**(1.9)**	(2.8)
Sales (1)	**198.0**	136.5	**346.9**	347.8
Realized risk management gain (loss) (2)	**(36.7)**	(1.7)	**(52.2)**	1.0
Gross revenues (1)	**$ 161.3**	$ 134.8	**$ 294.7**	$ 348.8

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

The Company's production revenues and gross revenues were higher in Q2 2026 compared to Q2 2025 due to higher realized oil prices.

For the first six months of 2026, the Company's production revenues were relatively consistent with the comparable period in 2025, as higher realized oil prices were offset by lower production volumes resulting from the Pembina Disposition, which closed at the beginning of Q2 2025. Gross revenues were further impacted by realized risk management losses on outstanding oil hedges.

Change in Gross Revenues (1)

(millions)	
Gross revenues – January 1 – June 30, 2025	$ 348.8
Decrease in liquids production	(53.7)
Increase in liquids prices	57.8
Decrease in natural gas production	(4.0)
Decrease in natural gas prices	(1.0)
Increase in realized oil risk management loss	(55.6)
Increase in realized natural gas risk management gain	2.4
Gross revenues – January 1 – June 30, 2026 (2)	$ 294.7

(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	
	2026	2025	**2026**	2025
Royalties (millions)	**$ 25.4**	$ 15.9	**$ 38.3**	$ 44.3
Average royalty rate (1)	**13%**	12%	**11%**	13%

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

The increase in absolute royalties and average royalty rate for Q2 2026 compared to Q2 2025 was primarily attributed to higher oil prices.

In the first six months of 2026, absolute royalties and the average royalty rate decreased compared with the same period in 2025, primarily reflecting production from new wells subject to royalty holidays, which carry lower royalty rates.

Expenses

	Three months ended June 30		Six months ended June 30	
(millions)	**2026**	2025	**2026**	2025
Net operating (1)	**$ 37.3**	$ 35.6	**$ 74.9**	$ 90.0
Transportation	**13.4**	11.8	**27.0**	28.6
Financing	**8.3**	8.7	**15.7**	21.4
Share-based compensation	**$ 8.8**	$ (0.2)	**$ 9.0**	$ 2.7

(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)	**2026**	2025	**2026**	2025
Operating costs	**$ 40.8**	$ 39.7	**$ 82.0**	$ 98.7
Less processing fees	**(2.0)**	(2.6)	**(4.1)**	(5.4)
Less road use recoveries	**(1.5)**	(1.5)	**(3.0)**	(3.3)
Net operating costs (1)	**$ 37.3**	$ 35.6	**$ 74.9**	$ 90.0

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

Operating and net operating costs in Q2 2026 were relatively unchanged compared to Q2 2025, as the sale of higher-cost production pursuant to the Pembina Disposition was largely offset by growth in Peace River production, which carries higher water handling costs. For the first six months of 2026, operating and net operating costs decreased compared to the corresponding period in 2025, primarily due to the impact of the Pembina Disposition, which closed at the beginning of Q2 2025.

To further improve operating efficiencies, the Company has focused on reducing trucking costs through water handling initiatives in Peace River during the first half of 2026. We are successfully implementing several initiatives and will continue to expand these efforts as we further grow our Peace River production base, thereby supporting continued improvements in operating efficiencies.

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 on a per boe basis in the first six months of 2026 compared to the 2025 comparable period. On an absolute basis transportation costs are roughly flat in the 2026 periods compared to the 2025 comparable periods. The prolonged spring break-up conditions impacted Peace River trucking costs in Q2 2026 and contributed to higher costs, while the Pembina Disposition in early Q2 2025 removed costs from that point forward.

Financing

Financing expense consists of the following:

	Three months ended June 30		Six months ended June 30	
(millions)	**2026**	2025	**2026**	2025
Interest	**$ 5.2**	$ 5.1	**$ 9.7**	$ 12.6
Accretion on decommissioning liability	**2.1**	2.7	**4.2**	7.3
Accretion on discount of senior unsecured notes	**-**	0.1	**-**	0.2
Accretion on lease liabilities	**0.5**	0.1	**0.9**	0.2
Loss on repurchased/redeemed senior unsecured notes	**-**	0.1	**-**	0.1
Deferred financing costs	**0.5**	0.6	**0.9**	1.0
Financing	**$ 8.3**	$ 8.7	**$ 15.7**	$ 21.4

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 the first half of 2026 compared to first half of 2025 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 $275.0 million, which was increased in Q2 2026 from $235.0 million. The current revolving period and maturity dates are May 31, 2027, and May 31, 2028, respectively.

At June 30, 2026, the Company had $175.0 million aggregate principal amount of 8.125% senior unsecured notes outstanding, maturing on December 3, 2030 (the "Notes"). Subsequent to June 30, 2026, the Company issued an additional $75.0 million aggregate principal amount of our existing Notes. The additional Notes were issued at a price of 102.75 resulting in an effective yield of 7.186% and gross proceeds of $77.1 million which were used to reduce drawings under our syndicated credit facility. Following the issuance, the aggregate principal amount outstanding of Notes increased to $250.0 million. The Notes constitute direct senior unsecured obligations of Obsidian Energy and rank equally with all of the Company's existing and future senior unsecured indebtedness.

At June 30, 2026, letters of credit totaling $2.5 million were outstanding (December 31, 2025 – $2.5 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") to acquire common shares granted under the Company's Stock Option Plan (the “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”), performance share units (“PSUs”) granted under the RPSU plan and unrealized gains or losses under the equity forward contracts.

Share-based compensation expense consisted of the following:

(millions)	Three months ended June 30 2026	Three months ended June 30 2025	Six months ended June 30 2026	Six months ended June 30 2025
DSUs	**$ (3.2)**	$ (1.5)	**$ 7.1**	$ (1.2)
PSUs	**0.1**	(1.1)	**7.6**	(0.6)
Equity forward contracts loss (gain) (1)	**8.9**	-	**(10.9)**	-
Liability based incentive plans	**$ 5.8**	$ (2.6)	**$ 3.8**	$ (1.8)
RSUs	**$ 1.6**	$ 1.9	**$ 3.1**	$ 3.6
Options	**1.4**	0.5	**2.1**	0.9
Equity based incentive plans	**3.0**	2.4	**5.2**	4.5
Share-based compensation	**$ 8.8**	$ (0.2)	**$ 9.0**	$ 2.7

(1) Relates to the equity forward contracts entered into to mitigate the Company's exposure to our share-based compensation plans.

The DSU and PSU obligations are measured at fair value based on the Company's share price at the balance sheet date. At June 30, 2026, the share price used to measure these obligations was $11.61 per share, compared to $13.22 per share at March 31, 2026, $8.42 per share at December 31, 2025, and $7.58 per share at June 30, 2025.

Unrealized gains and losses on the prepaid equity forward contracts are measured by comparing the contracts' fair value at each reporting date, including the change in fair value of contracts purchased during the period. Realized gains and losses are recognized only upon settlement.

The unrealized gain for the first six months of 2026 was based on the June 30, 2026, closing share price of $11.61 per share compared to the weighted average forward price for all of our equity forward contracts of $9.65 per share. For Q2 2026, the unrealized loss recognized in the period reflected quarter-over-quarter changes in our share price, including the impact of equity forward contracts entered into during the quarter at an average fair value of $13.33 per share.

General and Administrative Expenses ("G&A")

(millions, except per boe amounts)	Three months ended June 30 2026	Three months ended June 30 2025	Six months ended June 30 2026	Six months ended June 30 2025
Gross	**$ 10.1**	$ 9.9	**$ 20.7**	$ 20.8
Per boe (1)	**3.95**	3.78	**4.02**	3.42
Net (2)	**5.2**	5.0	**10.7**	10.6
Per boe (1)	**$ 2.05**	$ 1.92	**$ 2.09**	$ 1.74

(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 similar in the 2026 periods compared to the 2025 periods as staff levels were relatively consistent year-over-year. On a per boe basis, the impact of the Pembina Disposition in early Q2 2025 and resultant lower production levels led to higher costs in the 2026 periods compared to the 2025 periods.

Depletion, Depreciation and Impairment

(millions)	Three months ended June 30 2026	Three months ended June 30 2025	Six months ended June 30 2026	Six months ended June 30 2025
Depletion and depreciation (“D&D”)	**$ 46.2**	$ 45.5	**$ 92.2**	$ 88.7
PP&E Impairment	**$ 0.4**	$ 1.2	**$ 0.3**	$ 13.3

The Company's D&D expense increased in the 2026 periods compared to the corresponding periods in 2025, primarily due to the Pembina Assets being classified as held for sale prior to their disposition in 2025 and, accordingly, were no longer subject to depletion before the transaction closed.

During the first six months of 2026, we recorded a $0.3 million impairment (2025 - $14.2 million impairment reversal) in our Legacy cash generating unit ("Legacy CGU") due to changes in the decommissioning liability in the area. The Legacy CGU has no recoverable amount, as such changes in our decommissioning liability are either expensed or recovered each period.

Taxes

(millions)	Three months ended June 30 2026	Three months ended June 30 2025	Six months ended June 30 2026	Six months ended June 30 2025
Deferred income tax expense	**$ 13.0**	$ 4.3	**$ 7.1**	$ 9.3

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 in the 2026 and 2025 periods was due to the Company’s net income and resultant reduction of our deferred income tax asset.

Net Income

(millions, except per share amounts)	Three months ended June 30 2026	Three months ended June 30 2025	Six months ended June 30 2026	Six months ended June 30 2025
Net income	**$ 42.0**	$ 15.3	**$ 23.3**	$ 30.7
Basic per share	**0.63**	0.22	**0.35**	0.43
Diluted per share	**$ 0.61**	$ 0.21	**$ 0.34**	$ 0.41

Net income for Q2 2026 was higher than Q2 2025 primarily as a result of higher realized oil prices, which increased production revenues, although this was partially offset by higher risk management losses.

For the first six months of 2026, net income was lower than 2025 primarily as the result of a risk management loss on our outstanding hedging position, which was partially offset by lower royalties, operating costs and depletion due to lower production as a result of the Pembina disposition.

Capital Expenditures

(millions)	Three months ended June 30 2026	Three months ended June 30 2025	Six months ended June 30 2026	Six months ended June 30 2025
Drilling and completions	**$ 23.1**	$ 14.6	**$ 82.2**	$ 102.4
Well equipping and facilities	**15.3**	25.0	**32.7**	58.8
Land and geological/geophysical	**0.5**	0.5	**3.6**	6.9
Corporate	**0.2**	0.1	**0.3**	0.5
Capital expenditures	**$ 39.1**	$ 40.2	**$ 118.8**	$ 168.6
Property acquisitions, net	**97.8**	(210.9)	**98.4**	(210.9)
Total	**$ 136.9**	$ (170.7)	**$ 217.2**	$ (42.3)

In Q2 2026, capital expenditures were primarily directed toward completing and tying in wells drilled earlier in the year in Peace River and Willesden Green, while also furthering our Peace River waterflood initiatives. Overall, capital expenditures were relatively consistent with Q2 2025.

For the first six months of 2026, the Company took a disciplined approach to capital spending, moderating activity during Q1 2026 in response to lower commodity prices while preserving the flexibility to advance its development program in the second half of 2026 as market conditions improved.

For the first six months of 2026, 29 (23.5 net) wells were brought on production, including operated and non-operated activities, which included 10 (10.0 net) wells in Peace River, 9 (9.0 net) wells in Willesden Green and 10 (4.5 net) wells in PCU #11.

Drilling

	Six months ended June 30			
	2026		2025	
(number of wells)	**Gross**	**Net**	Gross	Net
Oil	**20**	**18**	35	31
Injectors, stratigraphic and service	**8**	**8**	2	2
Total	**28**	**26**	37	33

The Company drilled 24 (24.0 net) operated wells, including 4 (4.0 net) injector wells, during the first six months of 2026. In addition, the Company had non-operated working interests in 4 (1.8 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 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, 2026**	December 31, 2025
Long-term debt		
Syndicated credit facility	**$ 184.0**	$ 9.0
Senior unsecured notes (8.125%, maturing December 3, 2030)	**175.0**	175.0
Deferred financing costs	**(4.1)**	(4.1)
Total	**354.9**	179.9
Working capital deficiency		
Cash	**(0.2)**	-
Accounts receivable	**(77.8)**	(56.1)
Prepaid expenses and other	**(14.3)**	(11.0)
Prepaid equity forward contracts [1]	**(60.5)**	(28.1)
Bank overdraft	**-**	0.4
Accounts payable and accrued liabilities	**151.5**	155.0
Total	**(1.3)**	60.2
Net debt [2]	**$ 353.6**	$ 240.1

(1) The Company includes prepaid equity forward contracts in our working capital deficiency given we have paid for these contracts upon entering into them and the corresponding share-based compensation liabilities are included in Accounts Payable and Accrued Liabilities.
(2) Non-GAAP financial measure. See "Non-GAAP and Other Financial Measures".

Net debt increased compared to December 31, 2025, primarily as a result of higher drawings under our syndicated credit facility due to the Belly River Acquisition and our return of capital initiative through our share buyback program and the purchase of prepaid equity forwards contracts.

Liquidity

The Company has a reserve-based syndicated credit facility with a borrowing limit of $275.0 million (increased from $235.0 million) and $250.0 million of senior unsecured notes, including the July 2026 add-on note issuance of $75.0 million, maturing in December 2030. 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. In December 2025, we refinanced our existing senior unsecured notes, which provided additional term to our debt structure and additional proceeds, which we used to largely pay down our syndicated credit facility and increase the overall liquidity of the Company. With the $75.0 million note add-on in July, we reduced borrowings under our syndicated credit facility and further increased our liquidity. 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.

Financial Instruments

Obsidian Energy had the following financial instruments outstanding at June 30, 2026. 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.

Commodity contracts

	Notional Volume (bbl/d)	Remaining Term	Price (US$/bbl)	Fair value (millions)
Oil				
WTI Swap	8,950	July 2026	$ 76.15	$ 2.6
WTI Swap	2,250	August 2026	81.20	1.2
WTI Swap	1,375	September 2026	82.14	0.8
WTI Collar	5,050	August 2026	$ 80.25 - 87.69	$ 2.5
Total oil				**$ 7.1**

	Notional Volume (mcf/d)	Remaining Term	Price (C$/mcf)	Fair value (millions)
Natural Gas				
AECO Swap	35,077	July 2026 - October 2026	$ 2.69	$ 4.4
AECO Swap	4,739	November 2026 - March 2027	$ 3.31	$ 0.4
Total natural gas				**$ 4.8**
Total				**$ 11.9**

Foreign exchange forward contracts

	Notional Amount ($ millions)	Remaining Term	Price (C$)	Fair value (millions)
Foreign exchange forward contracts				
FX forward contract	$ 21.3	July 2026	$ 1.3729	$ (0.7)
FX forward contract	21.3	August 2026	1.3739	(0.7)
FX forward contract	$ 11.7	September 2026	$ 1.3866	$ (0.2)
Total				**$ (1.6)**

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

(millions)	Three months ended June 30 2026	Three months ended June 30 2025	Six months ended June 30 2026	Six months ended June 30 2025
Realized				
Settlement of oil contracts loss	**$ (40.5)**	$ (2.1)	**$ (57.9)**	$ (2.3)
Settlement of natural gas contracts gain	**3.8**	0.4	**5.7**	3.3
Settlement of foreign exchange contracts loss	**(0.7)**	-	**(0.6)**	-
Total realized risk management gain (loss)	**$ (37.4)**	$ (1.7)	**$ (52.8)**	$ 1.0
Unrealized				
Oil contracts gain (loss)	**$ 45.4**	$ 4.5	**$ 7.1**	$ (5.8)
Natural gas contracts gain (loss)	**(4.0)**	4.3	**1.2**	(0.6)
Foreign exchange contracts loss	**(0.3)**	-	**(1.6)**	-
Total unrealized risk management gain (loss)	**41.1**	8.8	**6.7**	(6.4)
Risk management gain (loss)	**$ 3.7**	$ 7.1	**$ (46.1)**	$ (5.4)

Prepaid Equity Forward Contracts

Obsidian Energy is exposed to equity price risk on our common share price in relation to our share-based compensation plans. Given the value of our share-based compensation plans fluctuates based on the Company's common share price on the Toronto Stock Exchange ("TSX") at each period end date, beginning in Q3 2025, the Company began mitigating this exposure by entering into equity forward contracts. Unrealized and realized gains/losses on our equity forward contracts for the period are recorded through share-based compensation.

	Share Volume	**Remaining Term [(1)]**	**Price (C$)**	**Fair value (millions)**
Equity				
Equity Forward Contract	720,000	September 2028	$ 8.89	$ 8.4
Equity Forward Contract	1,300,000	October 2028	8.72	15.1
Equity Forward Contract	550,000	November 2028	8.43	6.4
Equity Forward Contract	715,000	December 2028	8.31	8.3
Equity Forward Contract	450,000	January 2029	8.76	5.2
Equity Forward Contract	680,000	February 2029	10.18	7.9
Equity Forward Contract	710,000	April 2029	13.82	8.2
Equity Forward Contract	85,000	June 2029	$ 15.10	$ 1.0
Total	**5,210,000**		$ 9.65	**$ 60.5**

(1) The Company can settle the contract, or a portion of the contract, at any time.

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, 2026.

Based on commodity prices and contracts in place at June 30, 2026, 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 $0.5 million;
- a $0.10 change in the price per mcf of natural gas would change pre-tax unrealized risk management by $0.5 million;
- a $0.01 change in the CAD/US foreign exchange rate would change pre-tax unrealized risk management by $0.3 million; and
- a $1.00 change in our share price would change pre-tax unrealized risk management by $5.2 million.

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 Belly River Acquisition.

		Impact on funds flow from operations (1)	
Change of:	Change	$ millions	$/share
WTI - Price per barrel of liquids	WTI US$1.00	9.9	0.15
WCS - Price per barrel of liquids	WCS US$1.00	5.3	0.08
Liquids production	1,000 bbl/day	23.7	0.35
Price per mcf of natural gas	AECO $0.10	1.3	0.02
Natural gas production	1 mmcf/day	0.7	0.01
Effective interest rate	1%	1.1	0.02
Exchange rate ($US per $CAD)	$ 0.01	5.2	0.08

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

Contractual Obligations and Commitments

As at June 30, 2026, Obsidian Energy was committed to certain payments over the next five calendar years and thereafter as follows:

	2026	2027	2028	2029	2030	Thereafter	Total
Long-term debt (1)	**$ -**	$ -	$ 184.0	$ -	$ 175.0	$ -	$ 359.0
Transportation	**8.6**	16.0	12.5	12.1	5.7	-	54.9
Interest obligations	**12.3**	24.5	18.5	14.2	14.2	-	83.7
Lease liability	**1.7**	3.5	2.5	1.6	1.5	18.5	29.3
Decommissioning liability (2)	**5.9**	12.2	11.5	10.9	10.3	57.9	108.7
Total	**$ 28.5**	$ 56.2	$ 229.0	$ 38.8	$ 206.7	$ 76.4	$ 635.6

(1) The 2028 figure includes our syndicated credit facility which has a term-out date of May 2028. The 2030 figure includes our senior unsecured notes due in December 2030. 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, 2026, the Company had an aggregate of $175.0 million in senior unsecured notes maturing in December 2030 and the revolving period of our syndicated credit facility was May 31, 2027, with a term out period to May 31, 2028. In July 2026 the Company issued an additional $75.0 million in senior unsecured notes also maturing in December 2030. 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, 2026	66,762,000
Issuance under Option and RPSU Plans	3,570
Repurchase and cancellation of common shares	(40,000)
As at July 29, 2026	66,725,570

Options outstanding:	
As at June 30, 2026	2,798,041
Granted	7,770
As at July 29, 2026	2,805,811

RSUs outstanding:	
As at June 30, 2026	1,514,515
Granted	5,680
Vested	(6,873)
As at July 29, 2026	1,513,322

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, 2026 and 2025.

	Three months ended June 30		Six months ended June 30	
Daily production (boe/d)	**2026**	2025	**2026**	2025
Willesden Green/PCU #11 [(1)]				
Light oil (bbl/d)	**6,330**	5,568	**6,033**	8,684
Heavy oil (bbl/d)	**-**	24	**-**	49
NGLs (bbl/d)	**2,171**	2,107	**2,097**	2,546
Natural gas (mmcf/d)	**41**	41	**40**	50
Total production (boe/d)	**15,393**	14,462	**14,831**	19,687
Peace River				
Light oil (bbl/d)	**-**	11	**-**	6
Heavy oil (bbl/d)	**10,665**	11,910	**11,466**	11,303
NGLs (bbl/d)	**13**	16	**13**	15
Natural gas (mmcf/d)	**6**	5	**6**	5
Total production (boe/d)	**11,734**	12,827	**12,498**	12,221
Viking				
Light oil (bbl/d)	**288**	663	**344**	743
Heavy oil (bbl/d)	**72**	79	**80**	85
NGLs (bbl/d)	**29**	41	**29**	43
Natural gas (mmcf/d)	**3**	3	**3**	3
Total production (boe/d)	**778**	1,338	**849**	1,428
Legacy				
Light oil (bbl/d)	**78**	72	**67**	70
Heavy oil (bbl/d)	**20**	28	**23**	30
NGLs (bbl/d)	**24**	25	**24**	24
Natural gas (mmcf/d)	**1**	1	**1**	2
Total production (boe/d)	**295**	316	**287**	317
Total				
Light oil (bbl/d)	**6,696**	6,314	**6,444**	9,503
Heavy oil (bbl/d)	**10,757**	12,041	**11,569**	11,467
NGLs (bbl/d)	**2,237**	2,189	**2,163**	2,628
Natural gas (mmcf/d)	**51**	50	**50**	60
Total production (boe/d)	**28,200**	28,943	**28,465**	33,653

(1) Includes production from the Pembina Assets from January 1, 2025 to April 7, 2025. On April 7, 2025, the Company closed the Pembina Disposition. Production associated with the Pembina Assets averaged approximately 11,000 boe/d in Q1 2025.

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

Three months ended	**Jun. 30 2026**	Mar. 31 2026	Dec. 31 2025	Sep. 30 2025	Jun. 30 2025	Mar. 31 2025	Dec. 31 2024	Sep. 30 2024
Cash flow from operating activities	**$ 38.2**	$ 40.0	$ 42.6	$ 45.4	$ 55.2	$ 96.7	$ 115.0	$ 110.3
Change in non-cash working capital	**25.9**	(12.1)	(17.5)	(11.6)	4.3	(5.8)	(13.5)	6.1
Decommissioning expenditures	**1.3**	1.7	10.3	7.9	4.0	6.6	3.5	6.3
Equity forward contracts	**1.2**	31.2	21.3	7.4	-	-	-	-
Onerous office lease settlements	**-**	-	-	-	-	0.7	2.3	2.2
Deferred financing costs	**(0.5)**	(0.4)	(0.3)	(0.4)	(0.6)	(0.4)	(0.5)	(0.6)
Restructuring	**0.1**	0.2	0.1	0.1	0.7	0.1	-	-
Transaction costs	**1.2**	-	0.1	0.9	2.2	2.2	-	-
Other expenses	**0.4**	0.4	-	-	-	-	0.9	0.4
Funds flow from operations	**$ 67.8**	$ 61.0	$ 56.6	$ 49.7	$ 65.8	$ 100.1	$ 107.7	$ 124.7
Deferred share units	**(3.2)**	10.3	(1.1)	3.3	(1.5)	0.3	1.8	(5.1)
Performance share units	**0.1**	7.5	0.1	2.3	(1.1)	0.5	(0.5)	(1.8)
Equity forward contracts loss (gain)	**8.9**	(19.8)	0.7	(0.1)	-	-	-	-
Adjusted funds flow from operations	**$ 73.6**	$ 59.0	$ 56.3	$ 55.2	$ 63.2	$ 100.9	$ 109.0	$ 117.8

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, 2026 and ending on June 30, 2026 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

"Adjusted funds flow from operations" is cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures, equity forward contracts, onerous office lease settlements, the effects of financing related transactions from foreign exchange contracts and debt repayments, restructuring, transaction costs, certain other revenues and expenses and the impact on share based compensation of liability based incentive plans (includes the DSUs, PSUs and equity forward contracts gains and losses) and is representative of cash related to our underlying operations. Adjusted 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, Adjusted funds flow from operations and Free Cash Flow" and "Reconciliation of Cash flow from operating activities to Funds flow from operations and Adjusted funds flow from operations" above for reconciliations of adjusted funds flow from operations to cash flow from operating activities, being our nearest measure prescribed by IFRS.

“Free cash flow” is adjusted 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, Adjusted 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, equity forward contracts, onerous office lease settlements, the effects of financing related transactions from foreign exchange contracts and debt repayments, restructuring, transaction costs and certain other revenues and expenses and is representative of cash related to our underlying 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, Adjusted funds flow from operations and Free Cash Flow” and "Reconciliation of Cash flow from operating activities to Funds flow from operations and Adjusted 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 fees and road use recoveries 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. 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

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

“Adjusted funds flow from operations – diluted per share” is comprised of adjusted funds flow from operations divided by diluted weighted average common shares outstanding. Adjusted funds flow from operations is a non-

GAAP financial measure. See “Cash flow from Operating Activities, Funds Flow from Operations, Adjusted Funds Flow from Operations and Free Cash Flow” and “Reconciliation of Cash flow from operating activities to Funds flow from operations and Adjusted funds flow from Operations” above.

“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, Adjusted Funds Flow from Operations and Free Cash Flow” and “Reconciliation of Cash flow from operating activities to Funds flow from operations and Adjusted 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, Adjusted Funds Flow from Operations and Free Cash Flow” and “Reconciliation of Cash flow from operating activities to Funds flow from operations and Adjusted 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 anticipated benefits of the Belly River Acquisition and our growth strategy in the Willesden Green area, including that we expect to accelerate growth by leveraging our larger production base and expanded operational footprint; the expected growth in production of our Clearwater and Bluesky assets through further development and delineation of existing and new fields; the belief that we have a balanced portfolio of heavy and light oil with significant development opportunities that support our long-term growth strategy; that we continue to progress our enhanced oil recovery strategy through our waterflood initiatives, that we are encouraged by our results of such initiatives, and the expected benefits of such initiatives; that we expect to further advance our enhanced oil recovery program in the second half of the year; the continued development of our light oil production in Willesden Green through ongoing development; that the Company's pace and level of future development and growth depend on the macroeconomic environment and the Company's intention to generate acceptable returns and maintain our financial strength; that we remain committed to disciplined capital allocation and enhancing shareholder returns; that we remain committed to responsible environmental stewardship and our environmental remediation efforts including our focus on abandoning and reclaiming inactive fields; our hedges; our expectation that entering into equity forward contracts will help reduce volatility in our funds flow from operations and adjusted funds flow from operations; our belief that our water handling initiatives will help reduce trucking costs, and that we will expand such initiatives as we further expand our Peace River production base; the expectation that compliance with environmental legislation will require additional expenditures and a failure to comply may result in fines and penalties and the effect of such fines and penalties; 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 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 the Company actively manages our debt portfolio and considers opportunities to reduce or diversify our debt capital structure; that management contemplates both operating and financial risks and takes action as appropriate to limit the Company's exposure to certain risks; 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; and that the Company limits credit risk by executing counterparty risk procedures which include transacting only with institutions within its syndicated credit facility or companies with high credit ratings, and by obtaining financial security in certain circumstances.

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); 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 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 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 NCIB and the level thereof is uncertain. Any decision to acquire common shares of the Company pursuant to the NCIB 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 NCIB 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; risks associated with the refusal of the U.S. to renew the Canada-United States-Mexico Agreement ("CUSMA") by the July 1, 2026 deadline, including the risk that the U.S. ultimately withdrawing from CUSMA, which could result in a significant increase in trade barriers, which could in turn have a material adverse effect on the Canadian and U.S. economies, and by extension the Canadian oil and natural gas industry and the Company; 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 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 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 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, particularly between Iran, the United States and Israel; 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.

This document contains future-oriented financial information and financial outlook information (collectively, "FOFI") including all information disclosed under "Sensitivity Analysis" 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 the Company and the resulting financial results will likely vary from the amounts set forth herein and such variation may be material. The Company and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best 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, the Company 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 the Company's anticipated future business operations. Readers are cautioned that the FOFI contained in this document should not be used for purposes other than for which it is disclosed herein.

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.