RING ENERGY

REDEFINING CONVENTIONAL ASSETS

Q1 2026 EARNINGS REAFFIRM GUIDANCE

May 7, 2026

Forward-Looking Statements and Supplemental Non-GAAP Financial Measures

Forward – Looking Statements

This Presentation includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact included in this Presentation, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, guidance, plans and objectives of management are forward-looking statements. When used in this Presentation, the words "could," "may," "will," "believe," "anticipate," "intend," "estimate," "expect," "guidance," "project," "goal," "plan," "potential," "probably," "strategy", "target" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. Forward-looking statements also include assumptions and projections for quarterly 2026 guidance for sales volumes, number of potential well locations and associated inventory life, oil, NGL and natural gas mix as a percentage of total sales, capital expenditures, and operating expenses and the projected impacts thereon, and the number of wells expected to be drilled and completed. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. However, whether actual results and developments will conform to expectations is subject to a number of material risks and uncertainties, including but not limited to: declines in oil, natural gas liquids or natural gas prices; the level of success in exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities particularly in the winter; the timing of exploration and development expenditures; inaccuracies of reserve estimates or assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; impacts to financial statements as a result of impairment write-downs; risks related to level of indebtedness and periodic redeterminations of the borrowing base and interest rates under the Company's credit facility; Ring's ability to generate sufficient cash flows from operations to meet the internally funded portion of its capital expenditures budget; the impacts of hedging on results of operations; the effects of future regulatory or legislative actions; cost and availability of transportation and storage capacity as a result of oversupply, changes in U.S. energy, environmental, monetary and trade policies, including with respect to tariffs or other trade barriers, and any resulting trade tensions; political instability or armed conflict in major oil and natural gas producing regions outside the United States, including military hostilities in the Middle East (including the recent conflict between the United States and Iran), Russia, and Ukraine; and Ring's ability to replace oil and natural gas reserves. Such statements are subject to certain risks and uncertainties which are disclosed in the Company's reports filed with the Securities and Exchange Commission ("SEC"), including its Form 10-K for the fiscal year ended December 31, 2025, and its other filings with the SEC. All forward-looking statements, expressed or implied, included in this Presentation are expressly qualified by the cautionary statements and by reference to the underlying assumptions that may prove to be incorrect.

The Company undertakes no obligation to revise these forward-looking statements to reflect events or circumstances that arise after the date hereof, except as required by applicable law. The financial and operating estimates contained in this Presentation represent our reasonable estimates as of the date of this Presentation. Neither our independent auditors nor any other third party has examined, reviewed or compiled the estimates and, accordingly, none of the foregoing expresses an opinion or other form of assurance with respect thereto. The assumptions upon which the estimates are based are described in more detail herein. Some of these assumptions inevitably will not materialize, and unanticipated events may occur that could affect our results. Therefore, our actual results achieved during the periods covered by the estimates will vary from the estimated results. Investors are not to place undue reliance on the estimates included herein.

Supplemental Non-GAAP Financial Measures

This Presentation includes financial measures that are not in accordance with accounting principles generally accepted in the United States ("GAAP"), such as "Adjusted Net Income", "Adjusted EBITDA," "PV-10," "Adjusted Free Cash Flow" or "AFCF," "Adjusted Cash Flow from Operations" or "ACFFO," "Cash Return on Capital Employed" or "CROCE," "Leverage Ratio," "All-in Cash Operating Costs," and "Cash Operating Margin." While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. See Appendix for definitions and reconciliation to GAAP measures.

Ring Energy's Strategic Advantage

RING ENERGY

A Leader Redefining Conventional Assets Through Unconventional Thinking & Modern Technology to Deliver Sustainable Returns

A Proven Cash Flow Machine: 26 Consecutive Quarters of AFCF[1]

Conventional Asset Advantage: Shallow Decline, High Margin and Long Life

10+ Years of Drilling Inventory: 500+ Identified Locations[2]

Disciplined Consolidator in the Heart of the Permian: 3rd Largest E&P in CBP Texas[3]

Nimble Operator: High NRIs, Stacked Pay Zones with Multi-bench Hz Potential

1. Adjusted Free Cash Flow is a Non-GAAP financial measure. See Appendix for definitions and reconciliation to GAAP measures.
2. Defined as locations that can generate at least a 10% rate of return at $60 per Bbl oil and $2.50 per Mcf gas prices.
3. Source ENVERUS trailing twelve months as of Dec. 2025 for operators' Gross production on per Boe basis in the Texas CBP & NWS.

A Modern Conventional E&P Built for the Future

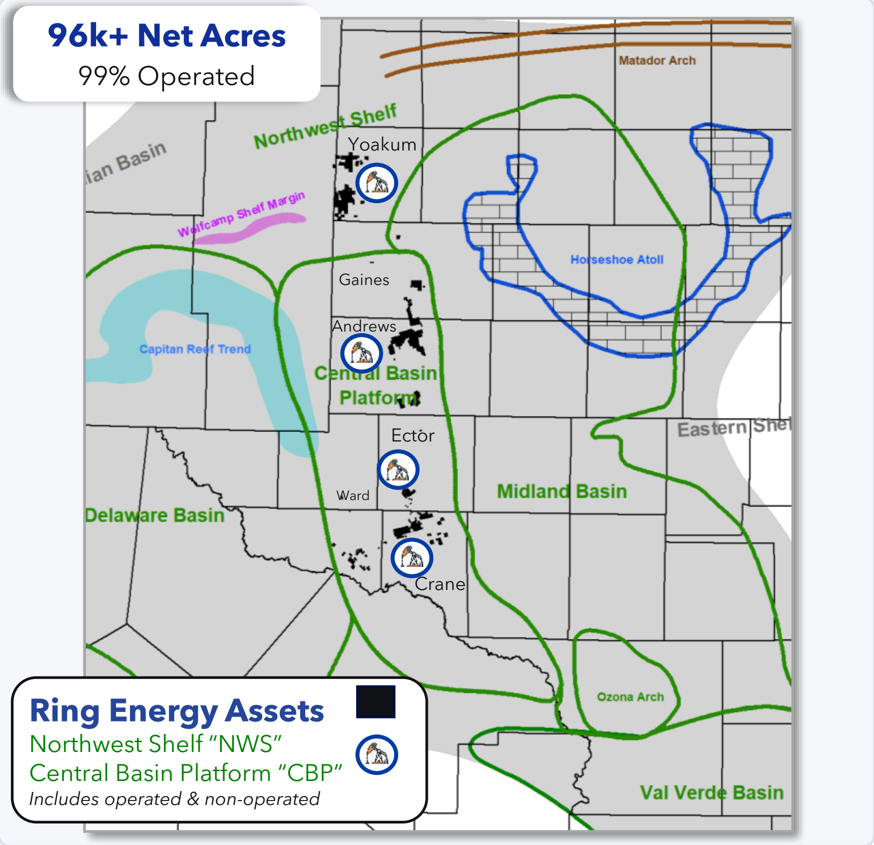
Transformation in Motion and Foundation Laid for Sustained Value Creation

Ring has built scale, inventory depth, and reduced leverage, creating a stronger foundation for long-term value

Production (MBoe/d)	1P Reserves (MMBoe)
8.8 → **20.3**	76.5 → **153**
+130% vs. YE 2020	+100% vs. YE 2020

PV-10 ($MM)	Leverage Ratio
$638 → **$1,318**	3.6x → **2.2x**
+107% vs. YE 2020	-38% vs. YE 2020

Inventory Runway	Reserve life
10+ yrs	**20+ yrs**
Long-duration development visibility	Cycle-resilient cash flow base



Ring Today[1] (May 1, 2026)

$381MM Market Cap
+575% vs. YE 2020

$806MM Enterprise Value
+120% vs. YE 2020

$160MM Liquidity
+294% vs. YE 2020

10+ Proven Pay Zones
+400% vs. YE 2020

Transformation Milestones

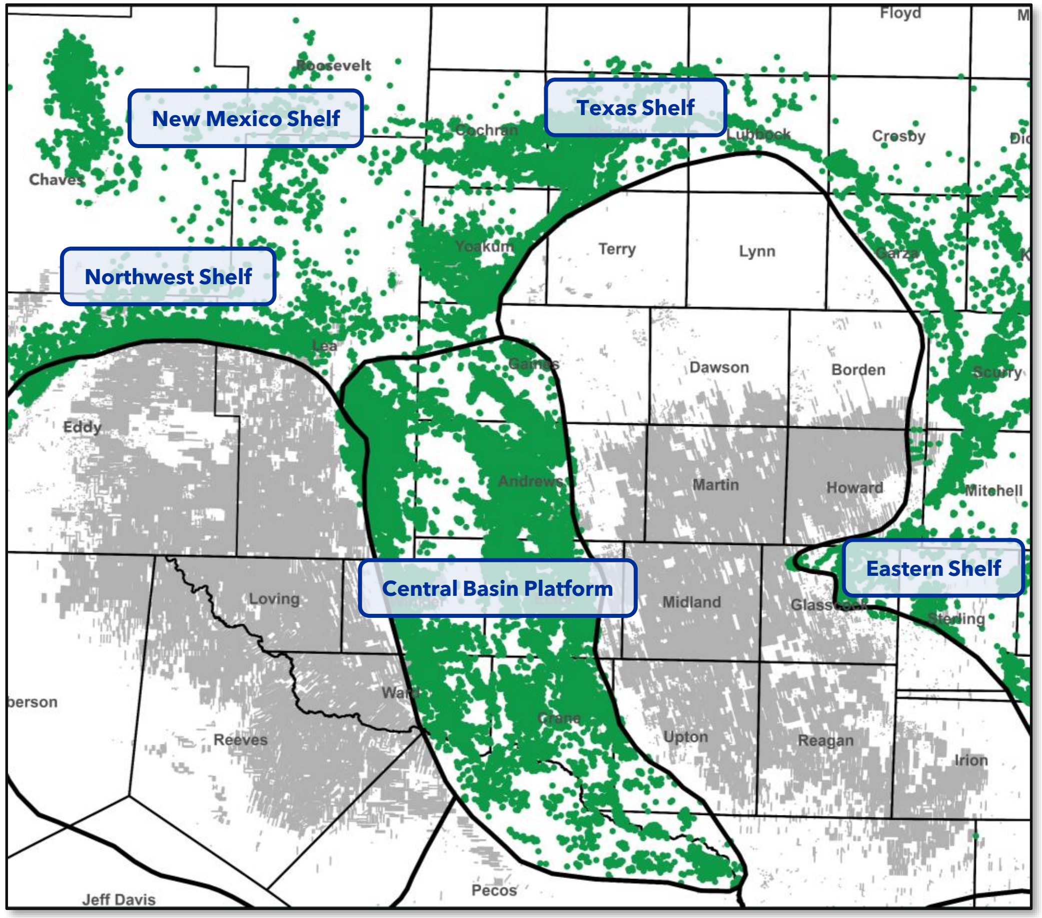
Reset	*Stabilize*	*Transform*	*Execute*	*Optimize*	*Sustainable*
2020	**2021**	**2022**	**2023**	**2024**	**2025+**
New Leadership Positioned for Recovery	Value-Focused Proven Strategy Disciplined Development	Stronghold Acquisition Doubled Production, Reserves and Inventory	Margin Expansion Increased Adj FCF Founders Acquisition	Debt Reduction Organic Focus Optimize Costs	Record Production & Adj FCF Cost Structure Reduction Scale Add- Organic Reserve Growth Lime Rock Acquisition

1. Market data is as of May 1, 2026. Balance sheet data is as of March 31, 2026.

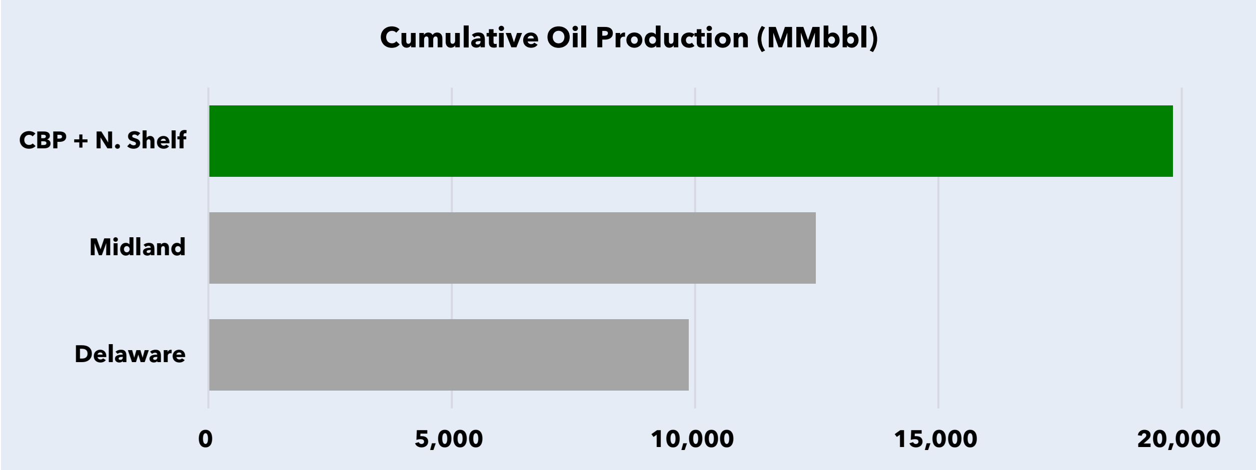
Ring's Thesis: Conventional Rock Is the Opportunity

The Central Basin Platform is the Heart of the Permian with Substantial Oil Left to Recover

Permian Platform and Shelf Fairways



CBP & Northwest Shelf Dominate Historical Permian Oil Production



Substantial Remaining Oil Resource → over15 billion barrels of recoverable oil remaining[1] in the CBP from bypassed tighter conventional stacked pay zones

Conventional Reservoirs → typically have higher porosity & permeability resulting in lower declines and longer well lives

Material Upside Ahead → The application of modern drilling / completion technology, and longer lateral development will unlock the next chapter of the CBP

Source: Enverus as of Apr. 23, 2026.

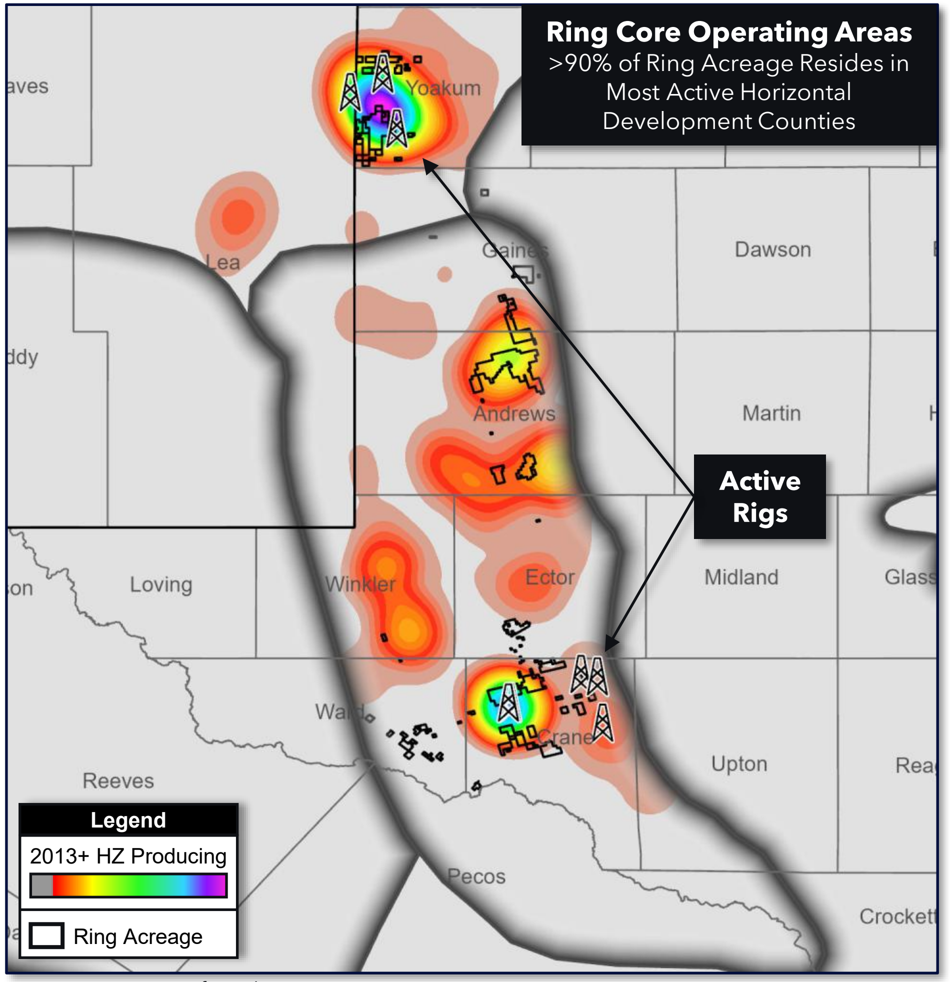
Note: Greater Permian includes the Central Basin Platform, Northwest Shelf, Eastern Shelf, Texas Shelf and New Mexico Shelf

1. Utilizing "Oil and Gas Resources Remaining in the Permian Basin: Targets for Additional Hydrocarbon Recovery" adjusted for production since publication

Why Now? Today's Modern Horizontal Technology

Unlocking Permian's Next Chapter – Ring's Core Acreage is Well Positioned

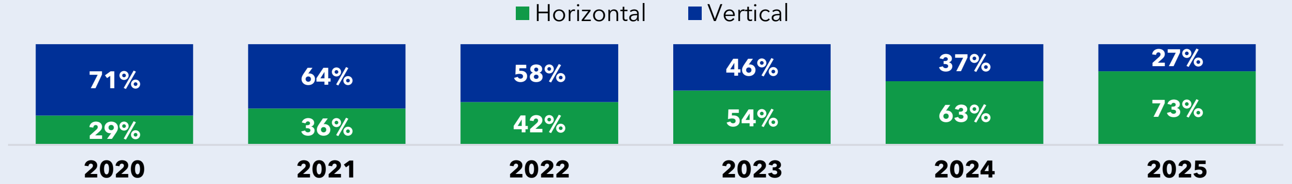
Material Horizontal Activity Across The CBP



Source: Enverus as of April 27, 2026.

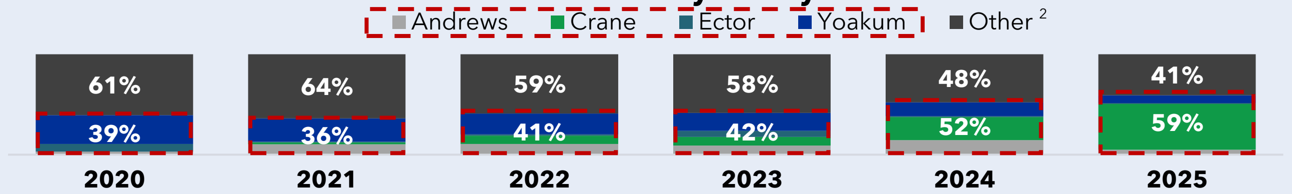
Horizontal Development Ramping Significantly

Greater Permian Horizontal vs. Vertical TILs[1]



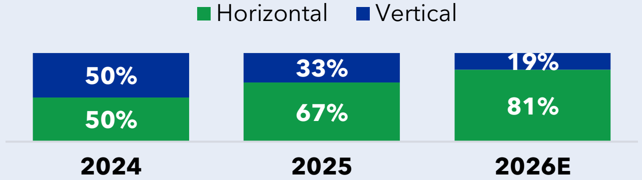
Ring Acreage Concentrated in the Highest-Activity Counties

Horizontal TILs by County[2]

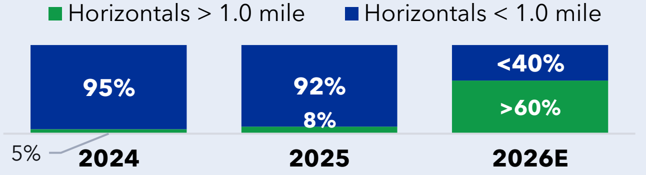


Ring 2026E New Drills are >80% Horizontal[3] with Increased Lateral Length

Ring Horizontal Gross Wells Drilled



Ring Horizontal Development Breakdown

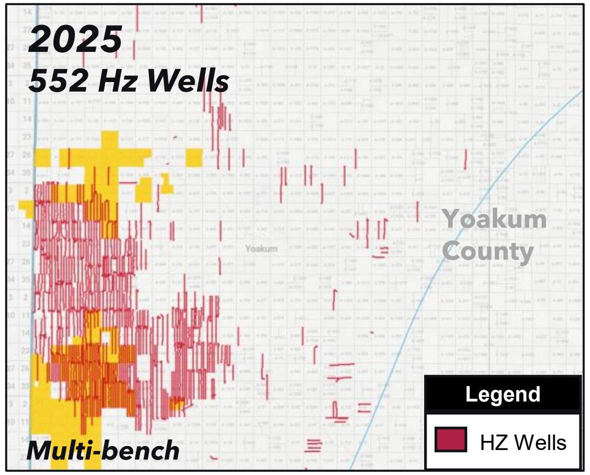


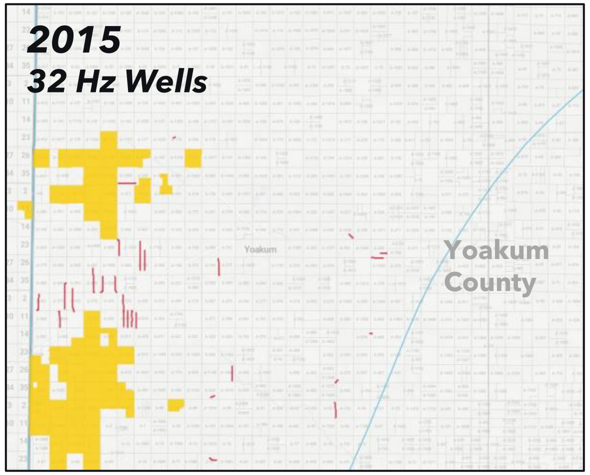
1. Includes the Central Basin Platform, Northwest Shelf, Eastern Shelf, Texas Shelf and New Mexico Shelf per Enverus.
2. Other counties include Borden, Chaves, Cochran, Coke, Cottle, Crockett, Crosby, Dickens, Ector, Eddy, Fisher, Foard, Gaines, Garza, Glasscock, Hale, Hockley, Howard, Irion, Kent, King, Lamb, Lea, Lubbock, Mitchell, Motley, Nolan, Pecos, Roosevelt, Schleicher, Scurry, Sterling, Stonewall, Terry, Tom Green, Upton, Ward, and Winkler.
3. Guidance Midpoint.

Proof it's Working – It's Repeatable and Scalable

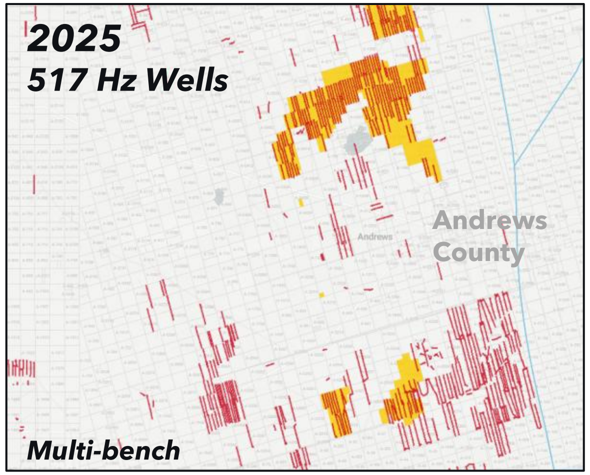
Horizontals Revitalize Legacy Fields and Fuel Rapid Production Growth in the Last ~ 5 Years

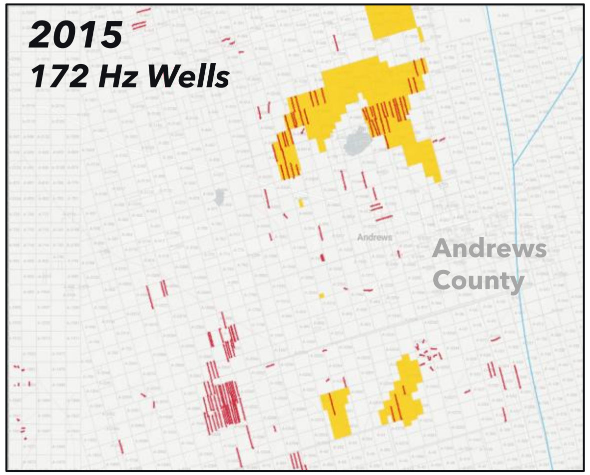
Yoakum 2025 vs 2015



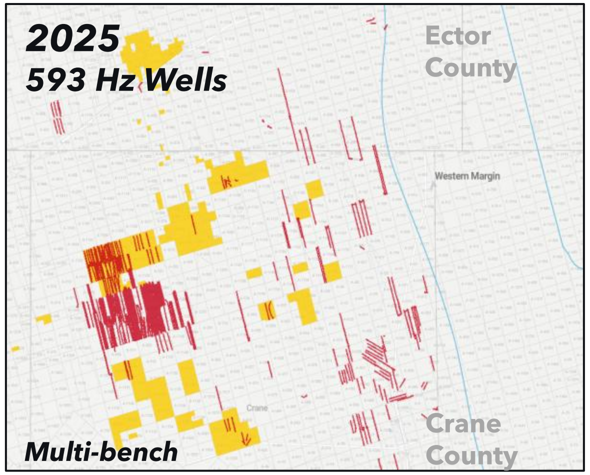


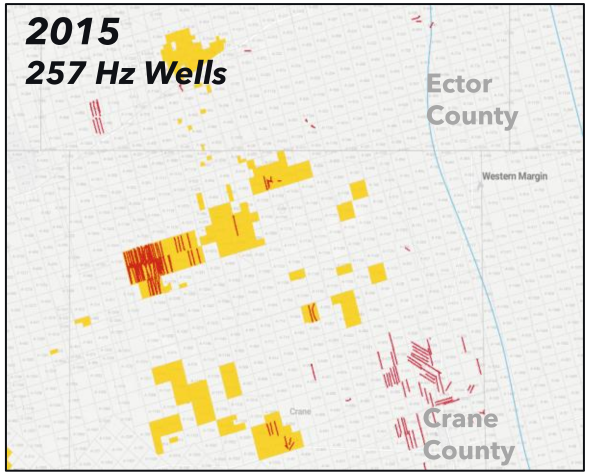
Andrews 2025 vs 2015





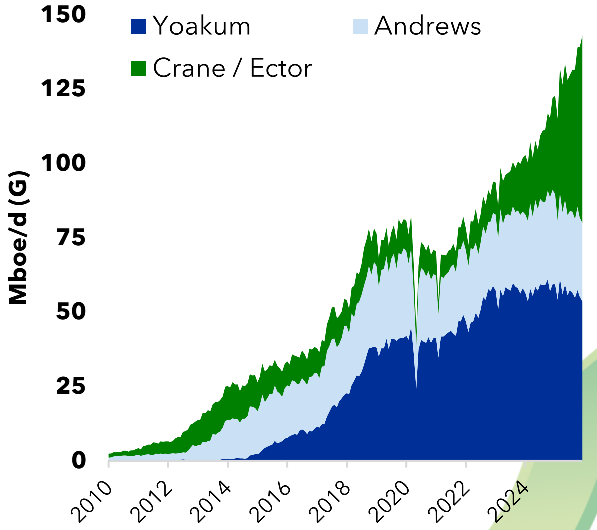
Ector / Crane 2025 vs 2015





CBP Multi-Bench Development

- Pre 2015 – **infancy of horizontal tech**
- Post 2015 - ~**1,200+ horizontal wells** drilled on core CBP & NWS counties
- **CBP & NWS resurgence** pioneered by horizontals drilled by Ring, Riley Permian, Blackbeard, Burk Royalty & Elevation
- **Multi-Bench Hz targets** include: Judkins, McKnight, Glorieta, Upper Clearfork, Tubb, Wichita Albany, Wolfcamp, Barnett & Devonian

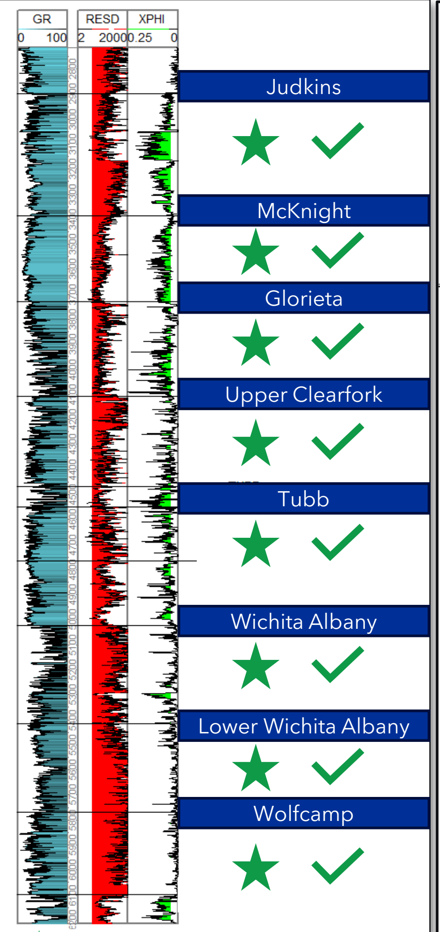


Source: Enverus.

Horizontals Unlock Higher-Return Inventory

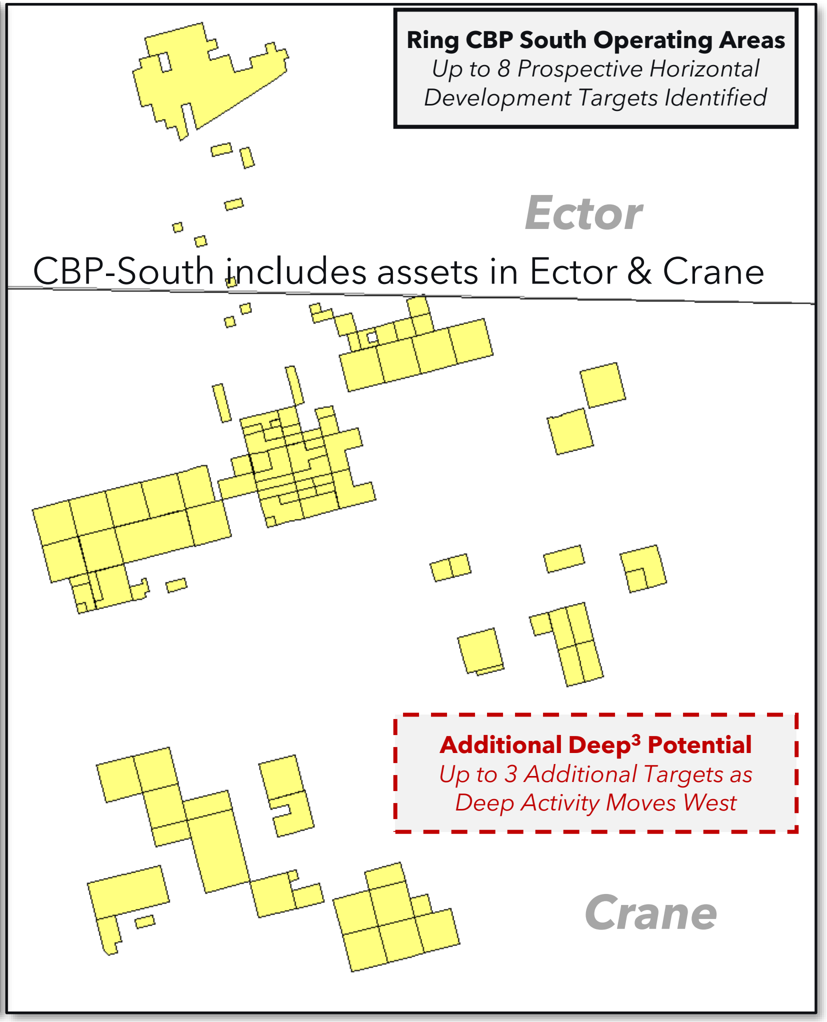
Shifting to Horizontal Development High-Grades and Increases Capital Efficient Inventory Potential

CBP South Multi-Bench Horizontal Development Opportunity



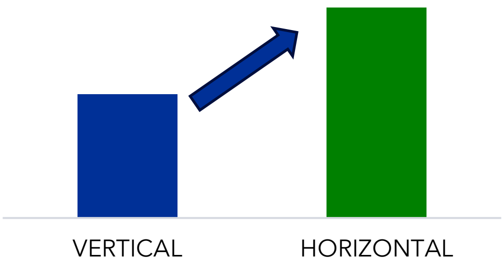
★ ***Actively Developed Offset REI***

✓ ***Prospective on REI Acreage***

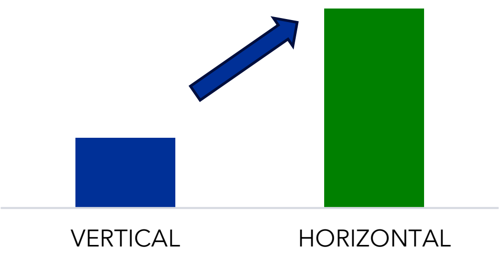


Significantly Enhancing Single-Well Profitability and Oil Recovery[1]

>65%
Increase in PV-10



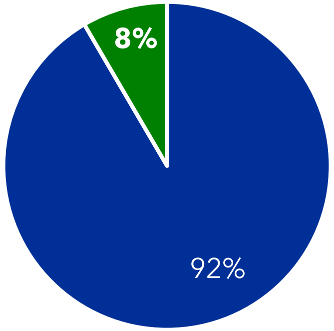
>180%
Increase in Oil Recovery



Strategic Repositioning of CBP South Inventory to Horizontal

Legacy YE'25 Proved Inventory

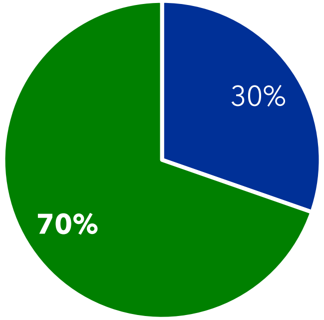
14 Horizontal Locations



■ Vertical ■ Horizontal

2026+ Inventory[2]

200+ Horizontal Locations



■ Vertical ■ Horizontal

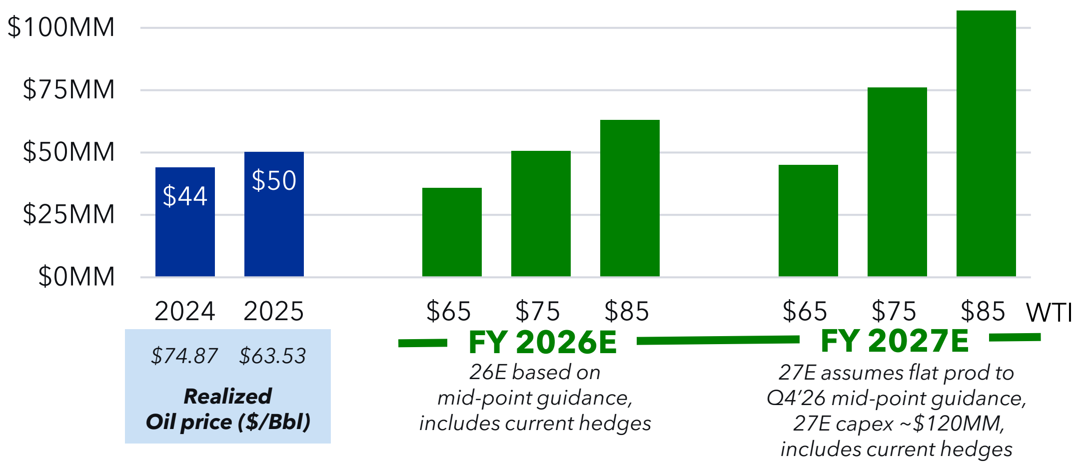
Note: Based on $70 / $3.50 Flat Pricing for WTI / HH

1. Reflects average metrics for currently identified economic vertical and horizontal inventory in Crane and Ector Counties
2. Includes all identified horizontal locations in Crane and Ector Counties
3. Deep targets include the Pennsylvanian, Barnett / Mississippian, and the Devonian

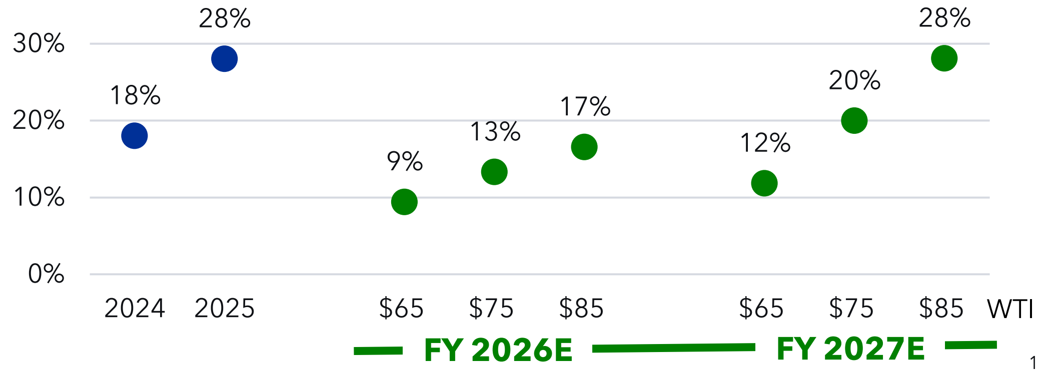
Meaningful Upside to Adjusted Free Cash Flow

2026 Hedges Support the Development Plan While Unhedged and Collar Volumes Give Exposure to Upside

Internal 2026E & 2027E Adjusted Free Cash Flow[1,2]

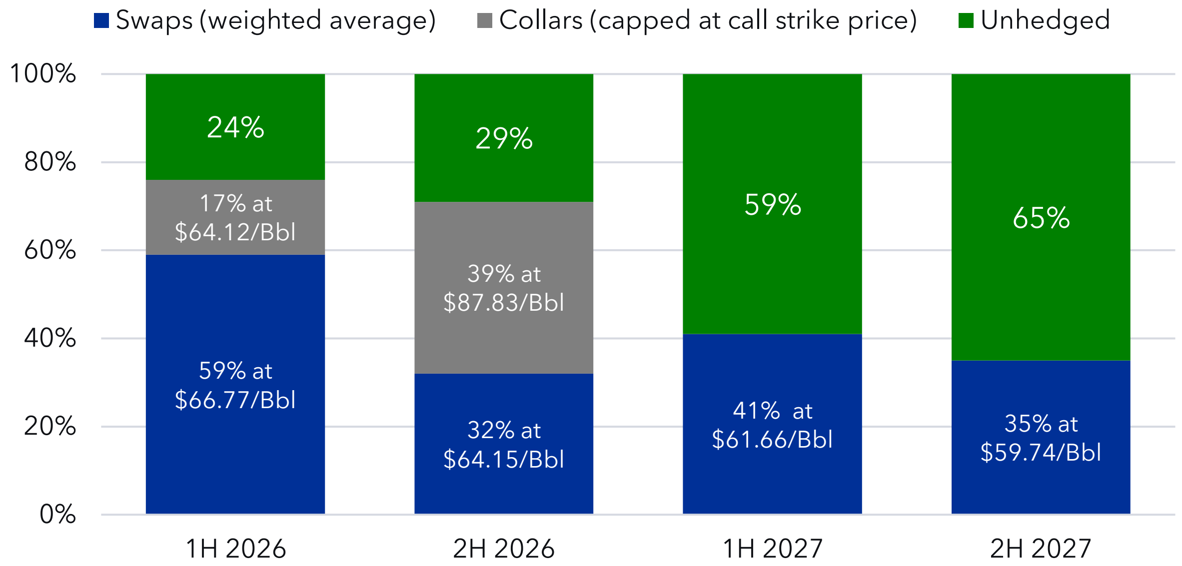


2026E & 2027E Adjusted Free Cash Flow Yield[2,3]



Disciplined Hedging Protects Cash Flow & Preserves Flexibility

Our hedge position was **built to support our capital development program** in a lower-price scenario, while **retaining meaningful upside** through collars and unhedged volumes



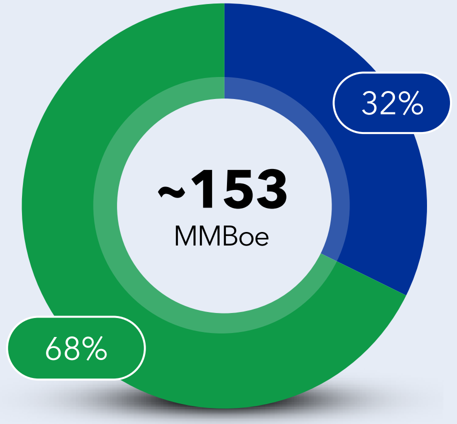
Note: Percentages for 2026 volumes are based on the midpoint of the Company's oil production guidance. Percentages for 2027 volumes are based on projecting the Company's Q426 oil production guidance flat through 2027.

1. Adjusted Free Cash Flow is a Non-GAAP financial measure. See Appendix for definition and reconciliation to GAAP measures.
2. Estimated AFCF is based on projections of internal management financial model and assumes mid point of guidance for "net sales", LOE & capex with flat WTI oil price beginning in June 2026 $3.50 per MCF Flat. Differential assumptions oil (-$1.00), gas '26E (-$5.50) '27E (-$3.40), and NGL realizations of 8% in '26E & 10% in '27E of WTI oil price.
3. AFCF yield for 2024 & 2025 based on year-end market capitalizations; 2026E & 2027E based on assumptions above for AFCF and Ring's stock price and market capitalization as of 5/1/2026.

High-Quality Proved Reserves Create Durable AFCF

Long Life Assets With Scale and Cycle Resilient Free Cash Flow Generation: **R/P 20+ Years**

Reserves by Category (%)

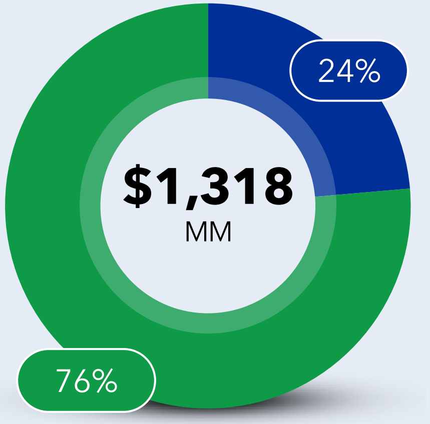


PD	~104 MMBoe	PUD	~49 MMBoe

LRR Acquisition + Organic Reserve Replacement in 2025

Increased Proved Reserves 14%
Increased PD Reserves 12%

Reserves by PV-10[2] ($MM)

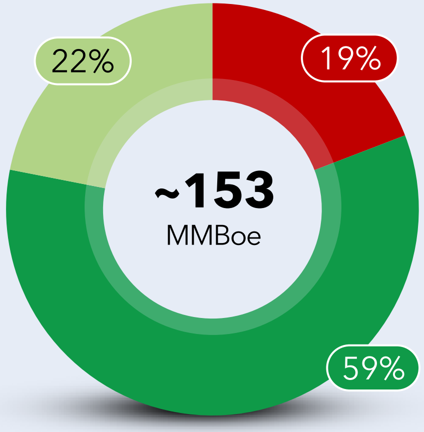


PD	$1,007 MM	PUD	$312 MM

Replaced Production and SEC Price[3] Volumes

7.4MM BOE Produced
5.9MM BOE SEC Price

Reserves by Product (%)



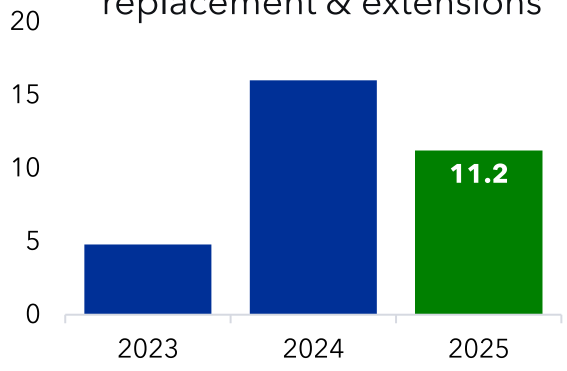
Oil (MMBO)	90.3	Gas (BCF)	176.2
NGL (MMBbL)	33.6		

11.2MM BOE of Extensions

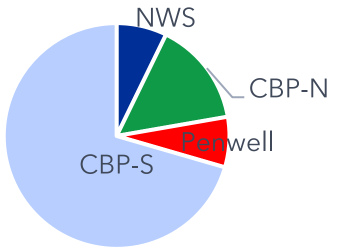
90% horizontal extensions

Reserve Extensions[4] (MMBoe)

3 years of reserve replacement & extensions



Proved Locations by Area

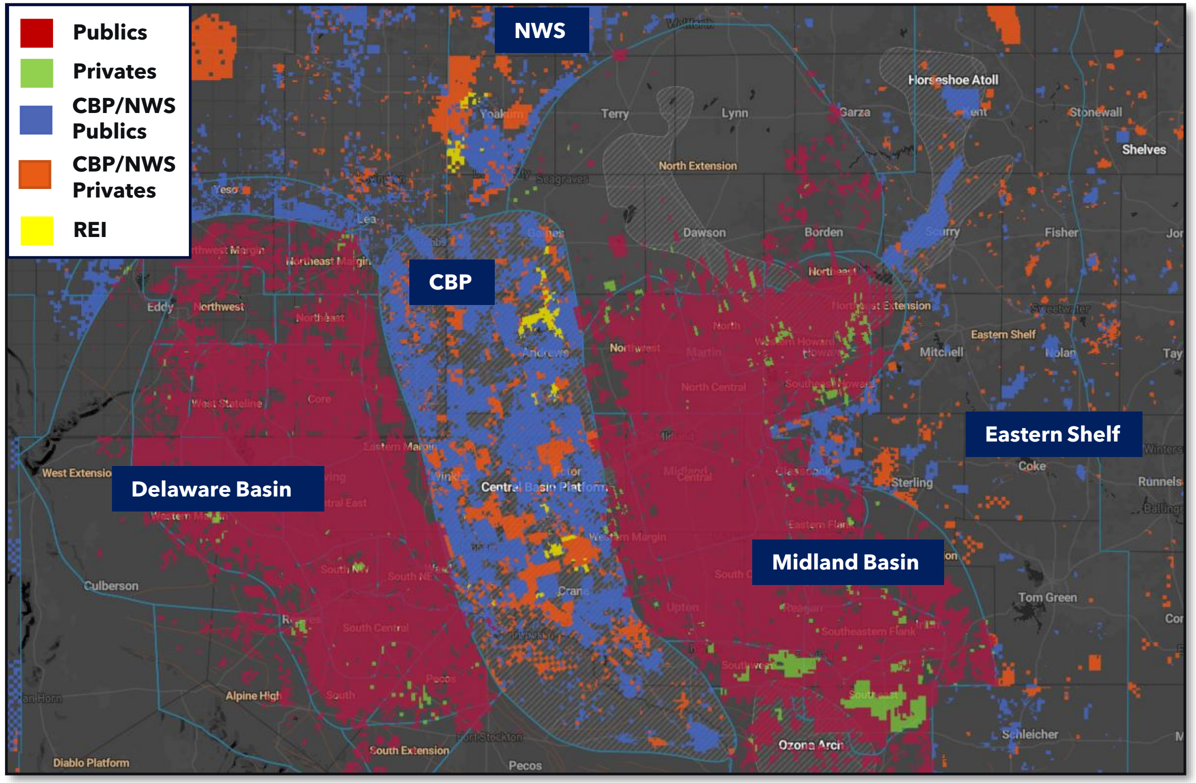


245+ PUD Locations
235+ PDNP Opportunities

1. Reserves as of December 31, 2025 utilizing SEC prices, YE 2025 SEC Pricing: $61.82 per Bbl Oil & $3.387 per Mcf Gas.
2. PV-10 is a Non-GAAP financial measure. See Appendix for definition and reconciliation.
3. Changes in proved reserves due to price and differentials (see Form 10-K for year ended December 31, 2025 for details).
4. See Form 10-K for year ended December 31, 2025 for additional information.

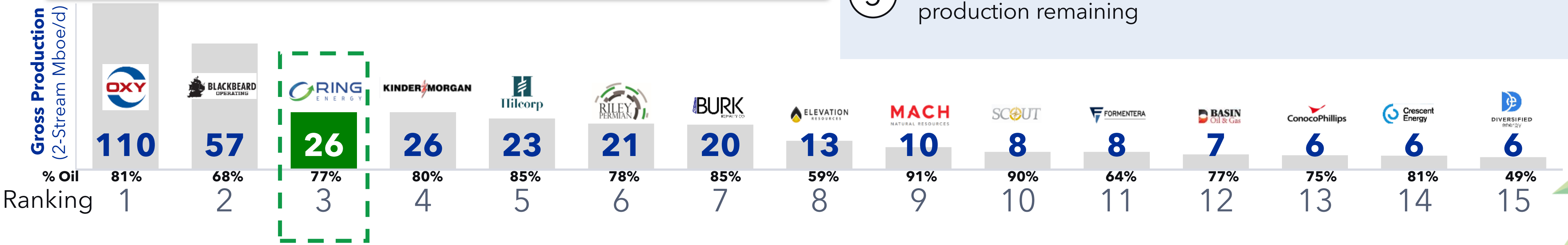
Permian's Premier Conventional Consolidator

Ring is One of the Top Three Operators in the CBP & NWS – Uniquely Positioned to Lead Consolidation



CBP & NWS: Fragmented Ownership is an Opportunity

1. **Scale gives Ring the edge –** Top-tier CBP/NWS footprint enables efficient acquisition integration
2. **Less competition, better deals –** Fewer competitors and low-cost assets drive superior acquisition economics
3. **Ring has already proven it –** Track record of accretive M&A and successful integrations
4. **Conventional is Ring's core competency –** Deep technical strength unlocks value others overlook
5. **The prize is massive –** ~410 Mboepd of fragmented conventional production remaining



Source: Enverus TTM 12/2025, Companies include Basin O&G, Blackbeard Operating, Burk Royalty, ConocoPhillips, Crescent Energy, Elevation Resources, Formentera Partners, Hilcorp, Kinder Morgan, OXY, Riley Petroleum, Ring Energy, Diversified Energy, Mach Natural Resources and Scout

Potential Catalysts for 2026 & Beyond

Organically Grow High-Quality Inventory and Reserves

Further Strengthen Balance Sheet and Increase Financial Flexibility

Ongoing Cost and Capital Efficiency Gains

Substantial Upside, Proved Reserves Trading Discount and Increasing Commodity Prices

RING ENERGY

Q1 2026 EARNINGS | MAY 7, 2026

Q1 UPDATE AND OUTLOOK

www.ringenergy.com | NYSE American: REI

Q1 2026 – Operational Results

Delivered on Production Guidance and Reduced Operating Costs while Accelerating Capital

✓ Production in-line with Guidance

- 12,276 barrels of oil sold per day
  (near the mid-point of guidance)
- 19,351 barrels of oil equivalent sold per day
  (mid-point of guidance)

✓ Maintained Cost Reductions

- LOE of $10.41 per Boe
  (Beat guidance low end range and 5% better than mid-point)
- All-in-Cash Costs of $21.77 per Boe
  (11% less than Q1 2025)

✓ Accelerated Capital Spend

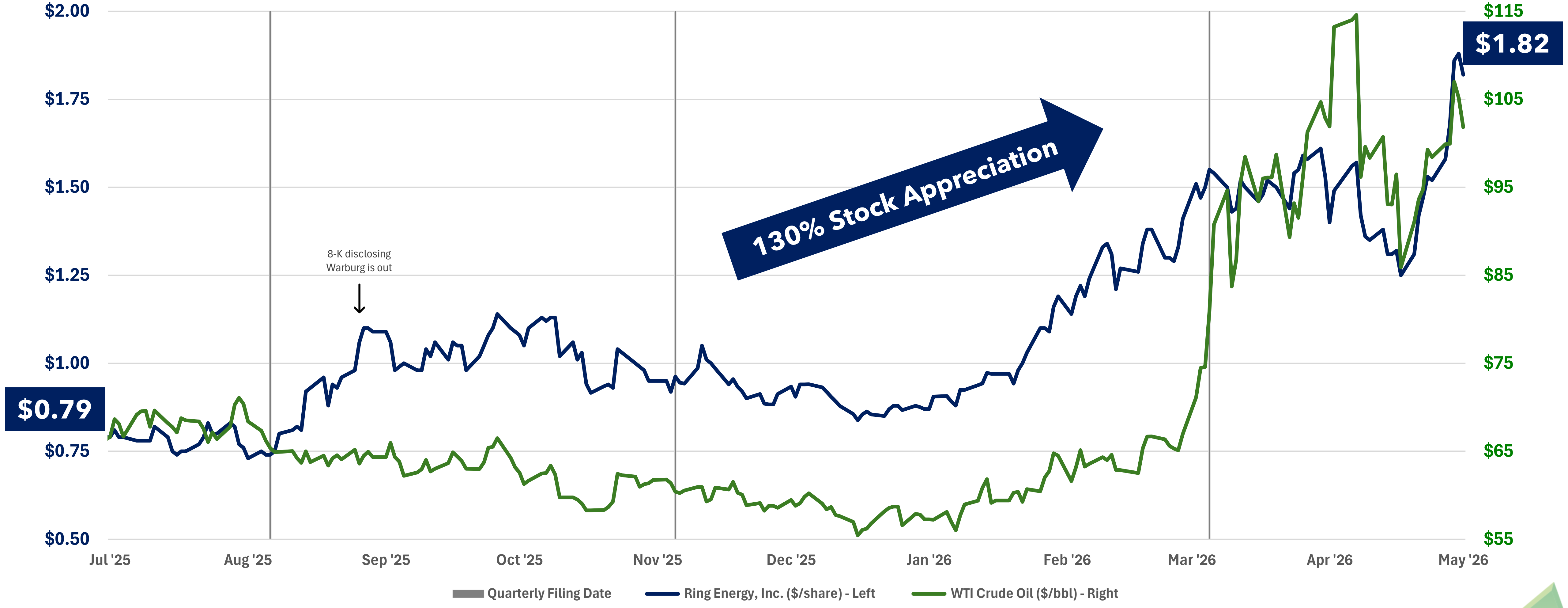
- Capture upside potential before sustained higher oil prices translate into higher costs and increased competition
- Invested in targeted infrastructure in order to expand flexibility and unlock more capital efficient longer lateral inventory

✓ 26th Consecutive Quarter of Positive Adjusted Free Cash Flow[1]

1. Adjusted Free Cash Flow is a Non-GAAP financial measure. See Appendix for definition and reconciliation to GAAP measures.

REI Historical Stock Price Performance

Price Performance Since July 1, 2025- Outperforming Most SMID CAP Peers YTD & LTM



Source: Facset, as of May 1st, 2026

Q1 2026E Guidance vs Actuals

Sales Volumes	Q1 2026 Guidance	Q1 2026 Actuals	% Difference
Total Oil (Bo/d)	12,100 – 12,500		
Mid Point (Bo/d)	**12,300**	**12,276**	**0%**
Total (Boe/d)	19,100 – 19,600		
Mid Point (Boe/d)	**19,350**	**19,351**	**0%**
- Oil (%)	64%	64%	
- NGLs (%)	20%	20%	
- Gas (%)	16%	16%	
Capital Program			
Capital[1] ($MM)	$28 – $34		
Mid Point ($MM)	**$31**	**$34.5**	**11%**
Operating Expenses			
LOE (per Boe)	$10.75 – $11.25		
Mid Point (per Boe)	**$11.00**	**$10.41**	**-5%**

Q1 Guidance Met Expectations

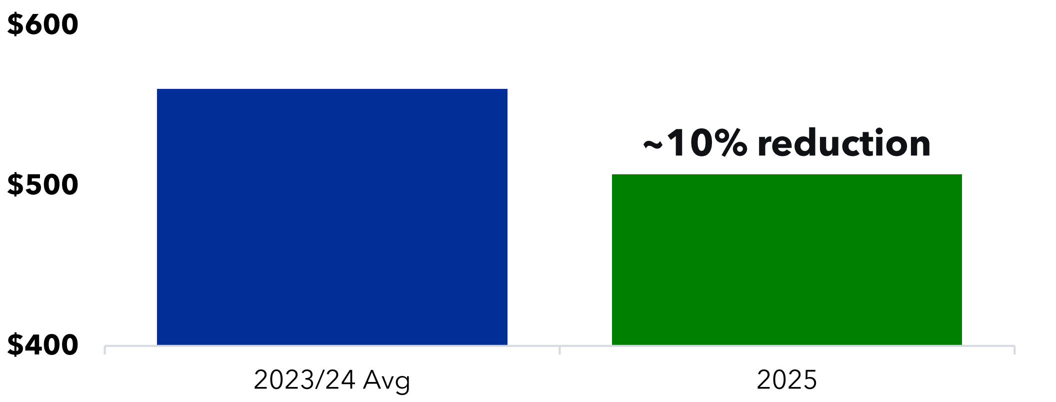
- ✓ Met mid-point production oil & Boe's
- ✓ Beat mid-point of lifting cost by 5%
- ▪ Slightly exceed high end capex, accelerated spend to benefit '26 outlook

1. In addition to Company-directed drilling and completion activities, the capital spending outlook includes funds for targeted well recompletions, capital workovers, infrastructure upgrades, and well reactivations. Also included is anticipated spending for leasing acreage; and non-operated drilling, completion, capital workovers, and facility improvements.

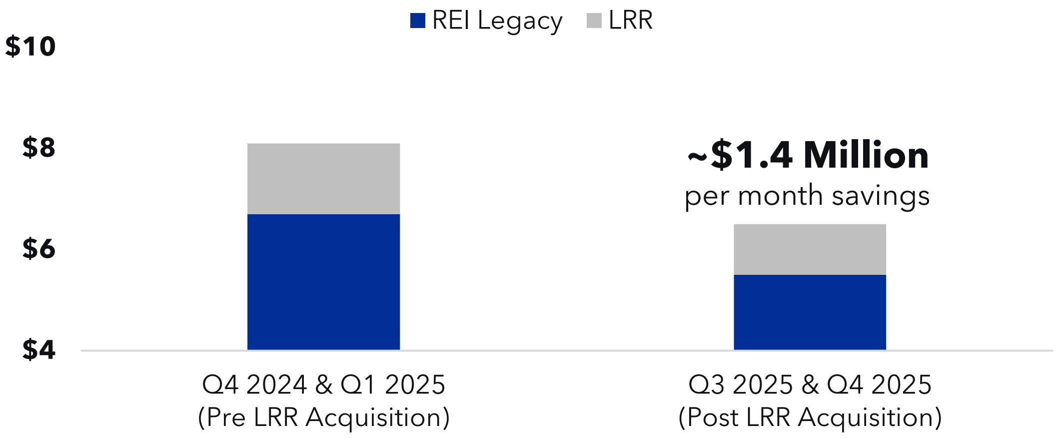
FY 2025 – Operational Excellence

Driving Sustainable Free Cash Flow Through Capital Efficiency and Ongoing Reductions to Operating Costs

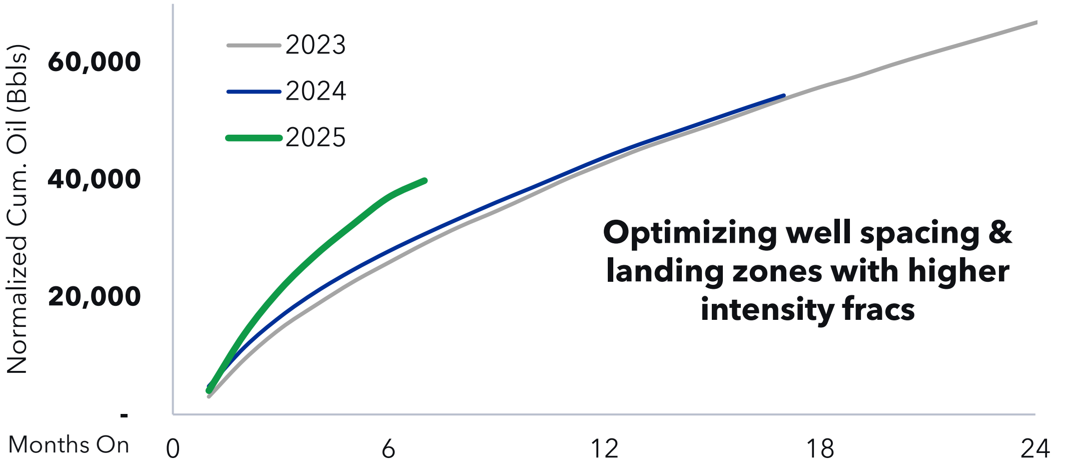
Reducing Hz D&C Cost Per Lateral Foot[1]



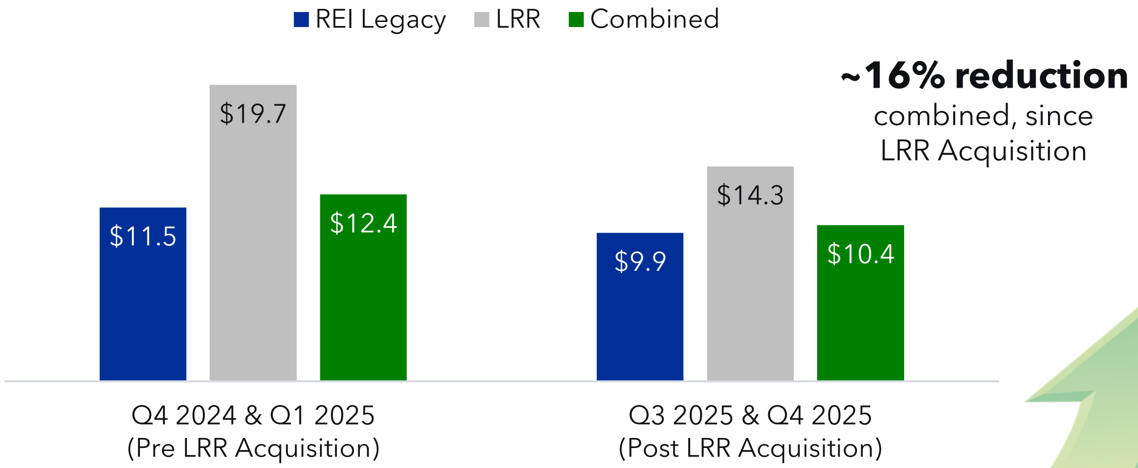
Structural Reduction in Monthly LOE $MM



Hz Well Performance Oil Bbls per 5,000 Lateral Feet[2]



Reducing LOE $ per Boe



1. D&C Cost is drilling, completion, equipment and connect to facility costs per lateral foot.
2. Well performance cumulative oil production gross barrels of oil normalized to 5,000 lateral feet. Total horizontal well counts per year 2023 (20), 2024 (21) and 2025 (12).

High-Margin Assets with Multi-Zone Horizontal Upside

RING ENERGY

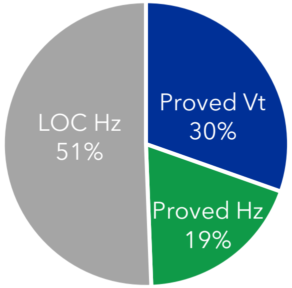
Unlocking Value Transitioning to Multi-Bench Horizontal Locations

2025 Core Assets	Central Basin Platform "CBP"	Northwest Shelf "NWS"
Counties	Andrews, Crane, Ector, Gaines	Yoakum
Net Acres	~79,000	~17,000
Operated WI / NRI	~96% / ~81%	~92% / ~69%
Net Production	~12 Mboe/d (68% oil)	~8.3 Mboe/d (62% oil)
Total Capital ($MM)	~$69	~$29
New Drill Program	7 Hz & 6 Vt wells	5 Hz wells
Field Level EBITDA Margin	~60%	~78%
Breakeven Costs[1]	< $50 per Bbl	< $40 per Bbl

Geologic Period	Target Formation "Stacked Pay Zones"		CBP Active	WPS	CBP Hz Potential	NWS Active	WPS
Permian	Grayburg		✓ ✓	4-6			
	San Andres	Judkins	✓		✓		
		McKnight	✓ ✓	4-6		✓ ✓	6-8
		Holt	✓		✓		
	Glorieta		✓		✓		
	Clearfork	Upper	✓		✓		
		Tubb	✓ ✓	4-6	✓		
		Lower	✓				
	Wichita - Albany		✓		✓		
	Wolfcamp		✓ ✓	3-5		✓	
Pennsylvanian	Penn						
Mississippian	Barnett Shale				✓		
	Mississippian Lime						
Devonian	Woodford						
	Devonian		✓ ✓	3-4			

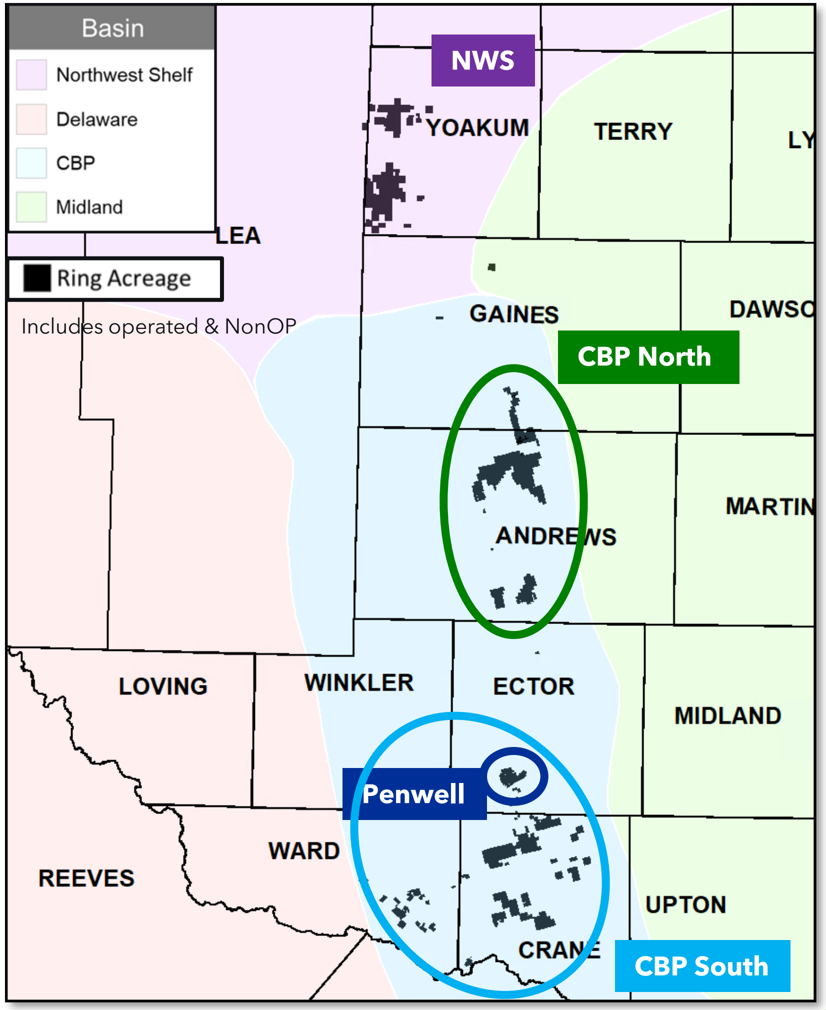
✓ Vertical ✓ Horizontal

500+ Total Gross New Drill Locations[2]



10+ years of drilling inventory at current activity levels

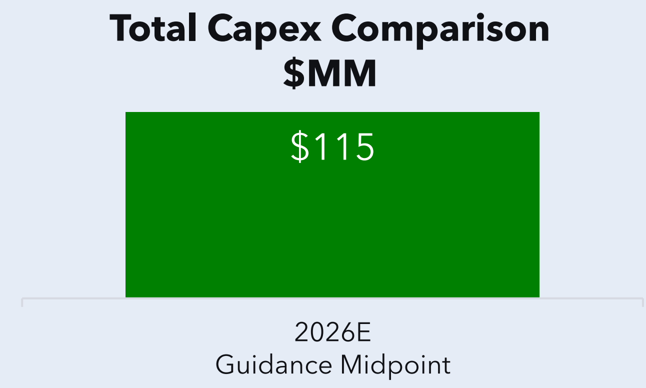
Converting legacy proved vertical zones into **multi-bench Hz value**

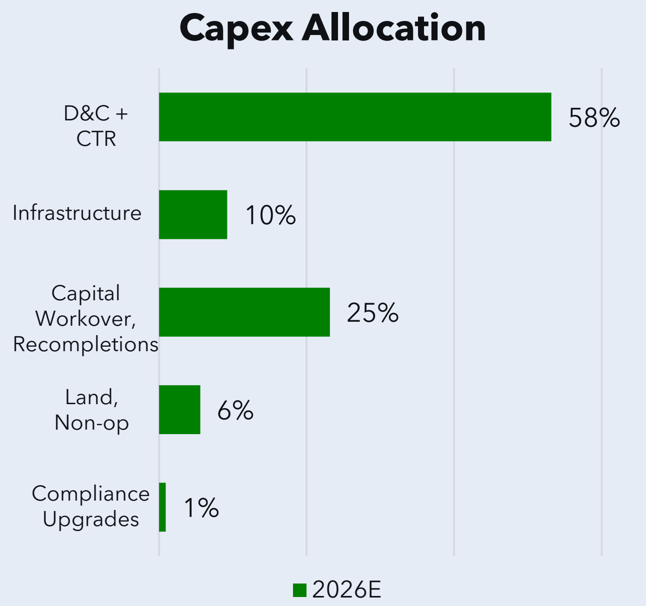


1. Break-even costs is for core inventory in CBP & NWS asset areas. The range in break-even is based on at least a 10% rate of return on recent capex spend, differentials, and depends on lateral length, asset area, completion and artificial lift type.
2. Defined as locations that we estimate that can generate at least a 10% rate of return at $60 per Bbl oil and $2.50 per Mcf gas prices.

Reaffirming 2026 Guidance

Sales Volumes	Q2 2026	Q3 2026	Q4 2026
Total (Bo/d)	12,450 – 13,450	12,750 – 13,750	12,800 – 13,800
Mid Point (Bo/d)	**12,950**	**13,250**	**13,300**
Total (Boe/d)	19,400 – 21,000	19,700 – 21,300	19,800 – 21,400
Mid Point (Boe/d)	**20,200**	**20,500**	**20,600**
- Oil (%)	64%	65%	65%
- NGLs (%)	20%	20%	20%
- Gas (%)	16%	15%	15%
Capital Program			
Capital[1] ($MM)	$28 – $36	$27 – $35	$17 – $25
Mid Point (millions)	**$32**	**$31**	**$21**
- New Hz wells drilled	5 – 7	5 – 7	3 – 5
- New Vertical wells drilled	1 – 2	1 – 2	1
- DUC Wells	0	0	0
- Wells completed & online	6 – 9	6 – 9	4 – 6
Operating Expenses			
LOE (per Boe)	$10.05– $11.05	$10.00 – $11.00	$10.00 – $11.00
Mid Point (per Boe)	**$10.55**	**$10.50**	**$10.50**





1. In addition to Company-directed drilling and completion activities, the capital spending outlook includes funds for targeted well recompletions, capital workovers, infrastructure upgrades, and well reactivations. Also included is anticipated spending for leasing acreage; and non-operated drilling, completion, capital workovers, and facility improvements.

Q1 2026 EARNINGS | MAY 7, 2026

THANK YOU

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Q1 2026 EARNINGS | MAY 7, 2026

APPENDIX

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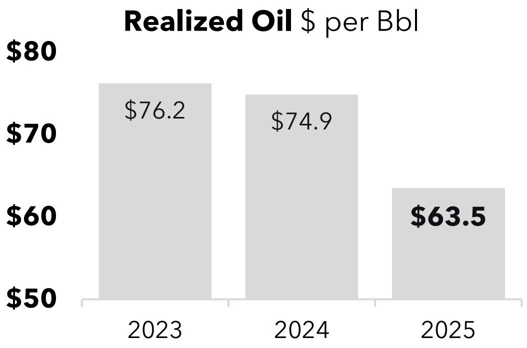
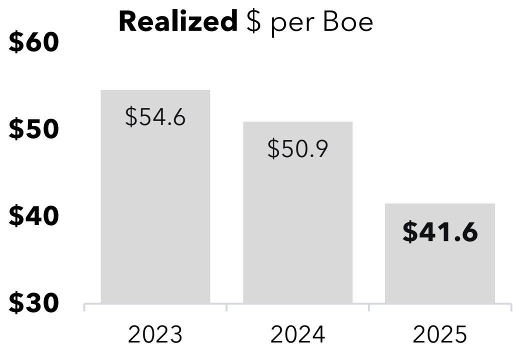
Operational Discipline Delivered Higher AFCF[1]

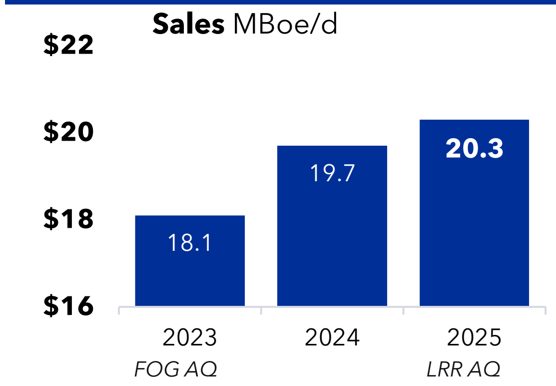
Business Execution Driving Growth And Stronger AFCF[1] Despite ~18% Lower Realized Prices

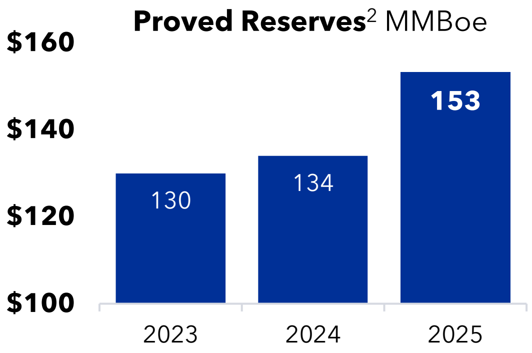
Commodity Prices



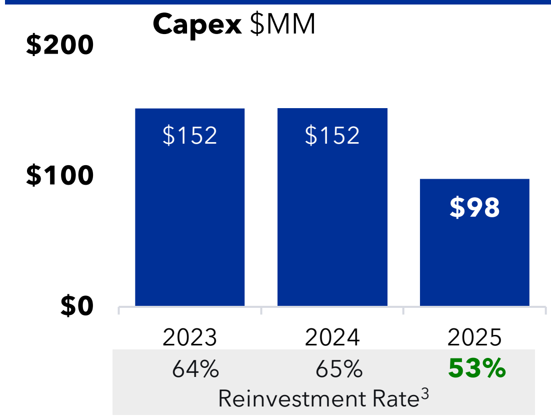


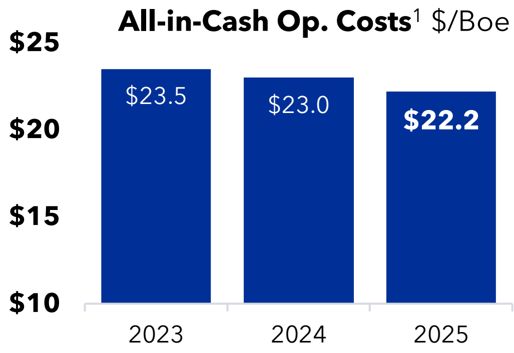
✓Additional Size & Scale

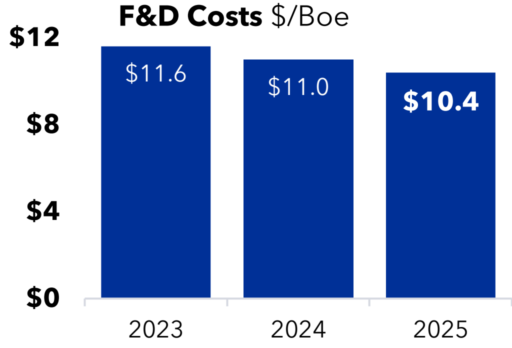




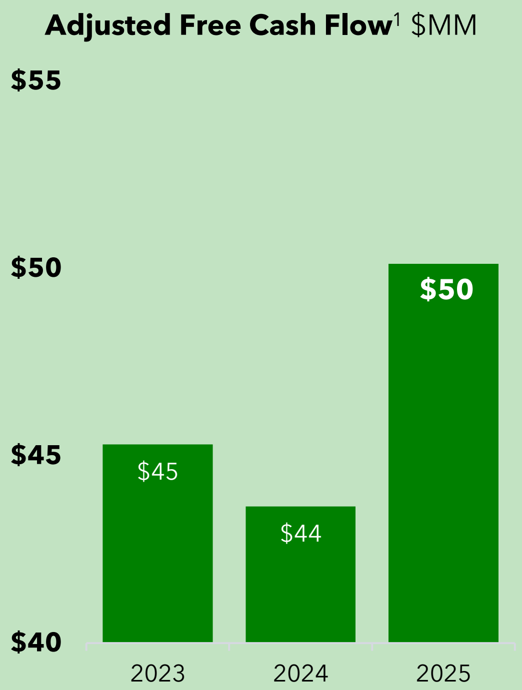
✓Operational Excellence







✓ Cash Flow Generation



1. Adjusted Free Cash Flow and All-in-Cash Operating Costs are Non-GAAP financial measures. See Appendix for definitions and reconciliation to GAAP measures.
2. SEC Proved Reserves as of 12/31/2025 utilizing SEC prices, YE 2025 SEC Pricing Oil $61.82 per Bbl Gas $3.387 per Mcf.
3. Reinvestment rate expressed as percentage of Adjusted EBITDA.

Derivative Summary

As of May 5, 2026

Oil Hedges (WTI)	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027	Q1 2028	Q2 2028	Q3 2028	Q4 2028	Q1 2029	Q2 2029	Q3 2029	Q4 2029
Swaps:															
Hedged volume (Bbl)	622,601	263,400	529,000	509,500	492,000	432,000	412,963	—	—	—	—	—	—	—	—
Weighted average swap price	$ 66.43	$ 61.77	$ 65.34	$ 62.82	$ 60.45	$ 61.80	$ 57.59	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Two-way collars:															
Hedged volume (Bbl)	273,000	563,685	368,000	—	—	—	—	400,080	—	—	—	—	—	—	—
Weighted average put price	$ 55.00	$ 60.82	$ 65.00	$ —	$ —	$ —	$ —	$ 55.45	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Weighted average call price	$ 65.65	$ 76.19	$ 105.65	$ —	$ —	$ —	$ —	$ 65.45	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Swaps: WTI NYMEX Rolls															
Hedged volume (BBL)	$ 819,000	$ 828,000	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Weighted average swap price	$ 5.30	$ 5.98	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

The Company has hedged:

Bal2026: **~ 2.6 million barrels of oil** at avg **upside protection price of $73.27**
2027: **~ 1.8 million barrels of oil** at avg **upside protection price of $60.78**

Derivative Summary

As of May 5, 2026

Gas Hedges (Henry Hub)	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027	Q1 2028	Q2 2028	Q3 2028	Q4 2028	Q1 2029	Q2 2029	Q3 2029	Q4 2029
NYMEX Swaps:															
Hedged volume (MMBtu)	1,165,628	600,016	1,072,305	439,678	423,035	1,079,906	1,046,151	1,012,567	984,322	956,865	931,539	908,117	886,933	866,585	846,134
Weighted average swap price	$ 3.82	$ 4.19	$ 3.99	$ 4.02	$ 4.02	$ 3.86	$ 4.02	$ 3.77	$ 3.77	$ 3.77	$ 3.77	$ 3.67	$ 3.67	$ 3.67	$ 3.67
Two-way collars:															
Hedged volume (MMBtu)	139,000	648,728	128,000	717,000	694,000	—	—	—	—	—	—	—	—	—	—
Weighted average put price	$ 3.50	$ 3.10	$ 3.50	$ 3.99	$ 3.00	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Weighted average call price	$ 5.42	$ 4.24	$ 5.42	$ 5.21	$ 4.32	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Gas Hedges (basis differential)	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027	Q1 2028	Q2 2028	Q3 2028	Q4 2028	Q1 2029	Q2 2029	Q3 2029	Q4 2029
Waha basis swaps:															
Hedged volume (MMBtu)	—	—	169,880	196,372	480,325	464,360	449,846	435,403	—	—	—	—	—	—	—
Weighted average spread price (1)	$ —	$ —	$ 1.32	$ 0.78	$ 0.78	$ 0.78	$ 0.78	$ 0.68	$ —	$ —	$ —	$ —	$ —	$ —	$ —
El Paso Permian Basin basis swaps:															
Hedged volume (MMBtu)	—	—	225,184	960,307	636,710	615,547	596,306	577,163	—	—	—	—	—	—	—
Weighted average spread price (1)	$ —	$ —	$ 1.35	$ 0.72	$ 0.67	$ 0.67	$ 0.67	$ 0.60	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(1) The gas basis swap hedges are calculated as the Henry Hub natural gas price less the fixed amount specified as the weighted average spread price above.

The Company has hedged:

Bal2026: **~ 3.8 BCF of natural gas** at avg **downside protection price of $3.78**
2027: **~ 4.4 BCF of natural gas** at avg **downside protection price of $3.81**

Non-GAAP Disclosure

Certain financial information included in this Presentation are not measures of financial performance recognized by accounting principles generally accepted in the United States ("GAAP"). These Non-GAAP financial measures are "Adjusted Net Income," "Adjusted EBITDA," "Adjusted Free Cash Flow" or "AFCF," "Adjusted Cash Flow from Operations" or "ACFFO," "Cash Return on Capital Employed" or "CROCE," "PV-10," "Leverage Ratio," "All-in Cash Operating Costs," and "Cash Operating Margin." Management uses these Non-GAAP financial measures in its analysis of performance. In addition, CROCE is a key metric used to determine a portion of the Company's incentive compensation awards. These disclosures may not be viewed as a substitute for results determined in accordance with GAAP and are not necessarily comparable to non-GAAP performance measures which may be reported by other companies.

"Adjusted Net Income" is calculated as net income (loss)minus the estimated after-tax impact of share-based compensation, ceiling test impairment, unrealized gains and losses on changes in the fair value of derivatives, and transaction costs for acquisitions and divestitures ("A&D"). Adjusted Net Income is presented because the timing and amount of these items cannot be reasonably estimated and affect the comparability of operating results from period to period, and current period to prior periods. The Company believes that the presentation of Adjusted Net Income provides useful information to investors as it is one of the metrics management uses to assess the Company's ongoing operating and financial performance, and also is a useful metric for investors to compare the Company's results with its peers.

The Company defines "Adjusted EBITDA" as net income (loss) plus net interest expense (including interest income and expense), unrealized loss (gain) on change in fair value of derivatives, ceiling test impairment, income tax (benefit) expense, depreciation, depletion and amortization, asset retirement obligation accretion, transaction costs for acquisitions and divestitures (A&D), share-based compensation, loss (gain) on disposal of assets, and backing out the effect of other income. Company management believes Adjusted EBITDA is relevant and useful because it helps investors understand Ring's operating performance and makes it easier to compare its results with those of other companies that have different financing, capital and tax structures. Adjusted EBITDA should not be considered in isolation from or as a substitute for net income, as an indication of operating performance or cash flows from operating activities or as a measure of liquidity. Adjusted EBITDA, as Ring calculates it, may not be comparable to Adjusted EBITDA measures reported by other companies. In addition, Adjusted EBITDA does not represent funds available for discretionary use.

The Company defines "Adjusted Free Cash Flow" or "AFCF" as Net Cash Provided by Operating Activities (as reflected on the Company's Condensed Statements of Cash Flows) less changes in operating assets and liabilities, and plus transaction costs for acquisitions and divestitures ("A&D"), current income tax expense (benefit), proceeds from divestitures of equipment for oil and natural gas properties, loss (gain) on disposal of assets, and less capital expenditures, credit loss expense, and other income. For this purpose, the Company's definition of capital expenditures includes costs incurred related to oil and natural gas properties (such as drilling and infrastructure costs and lease maintenance costs) but excludes acquisition costs of oil and gas properties from third parties that are not included in the Company's capital expenditures guidance provided to investors. Management believes that Adjusted Free Cash Flow is an important financial performance measure for use in evaluating the performance and efficiency of the Company's current operating activities after the impact of capital expenditures and net interest expense (including interest income and expense, excluding amortization of deferred financing costs) and without being impacted by items such as changes associated with working capital, which can vary substantially from one period to another. Other companies may use different definitions of Adjusted Free Cash Flow.

The table below provides detail of PV-10 to the standardized measure of discounted future net cash flows as of December 31, 2025. ($ in 000's)

Present value of estimated future net revenues (PV-10)	$ 1,318,208
Future income taxes, discounted at 10%	$ 194,715
Standardized measure of discounted future net cash flows	$ 1,123,493

The Company defines "Adjusted Cash Flow from Operations" or "ACFFO" as Net Cash Provided by Operating Activities, as reflected in the Company's Condensed Statements of Cash Flows, less the changes in operating assets and liabilities, which includes accounts receivable, inventory, prepaid expenses and other assets, accounts payable, and settlement of asset retirement obligations, which are subject to variation due to the nature of the Company's operations. Accordingly, the Company believes this financial performance measure is useful to investors because it is used often in its industry and allows investors to compare this metric to other companies in its peer group as well as the E&P sector.

"Leverage" or the "Leverage Ratio" is calculated pursuant to the Company's existing senior revolving credit facility and means as of any date, the ratio of (i) Consolidated Total Debt as of such date to (ii) Consolidated EBITDAX for the four consecutive fiscal quarters ending on or immediately prior to such date for which financial statements are required to have been delivered under the credit facility. The Company defines "Consolidated Total Debt" in accordance with its existing senior revolving credit facility and means, as of any date, all Indebtedness of the Company on a consolidated basis as of such date, but excluding hedging obligations. The Company defines "Consolidated EBITDAX" in accordance with its existing senior revolving credit facility and means for any period an amount equal to the sum of (i) consolidated net income (loss) for such period plus (ii) to the extent deducted in determining consolidated net income (loss) for such period, and without duplication, (A) consolidated interest expense, (B) income tax expense (benefit) determined on a consolidated basis, (C) depreciation, depletion and amortization determined on a consolidated basis, (D) exploration expenses determined on a consolidated basis, and (E) all other non-cash charges reasonably acceptable to the administrative agent, in each case for such period minus (iii) all noncash income added to consolidated net income (loss) for such period; provided that, for purposes of calculating compliance with the financial covenants under the credit facility, to the extent that during such period the Company has consummated an acquisition permitted by the credit facility or any sale, transfer or other disposition of any property or assets permitted by the credit facility, Consolidated EBITDAX will be calculated on a pro forma basis with respect to the property or assets acquired or disposed of. The maximum permitted Leverage Ratio under the senior revolving credit facility is 3.00.

PV-10 is a Non-GAAP financial measure that differs from a financial measure under GAAP known as "standardized measure of discounted future net cash flows" in that PV-10 is calculated without including future income taxes. Management believes that the presentation of the PV-10 measure of the Company's oil and natural gas properties is relevant and useful to investors because it presents the estimated discounted future net cash flows attributable to its estimated proved reserves independent of its income tax attributes, thereby isolating the intrinsic value of the estimated future cash flows attributable to its reserves. Management believes the use of a pre-tax measure provides greater comparability of assets when evaluating companies because the timing and quantification of future income taxes is dependent on company-specific factors, many of which are difficult to determine. For these reasons, management uses and believes that the industry generally uses the PV-10 measure in evaluating and comparing acquisition candidates and assessing the potential rate of return on investments in oil and natural gas properties. PV-10 does not necessarily represent the fair market value of oil and natural gas properties. PV-10 is not a measure of financial or operational performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

The Company defines "Cash Return on Capital Employed" or "CROCE" as Adjusted Cash Flow from Operations divided by average debt and shareholder equity for the period.

The Company defines All-In Cash Operating Costs, a Non-GAAP financial measure, as "all in cash" costs which includes lease operating expenses, G&A costs excluding share-based compensation, net interest expense (including interest income and expense, excluding amortization of deferred financing costs), workovers and other operating expenses, production taxes, ad valorem taxes, and gathering/transportation costs. Management believes that this metric provides useful additional information to investors to assess the Company's operating costs in comparison to its peers, which may vary from company to company.

The Company defines Cash Operating Margin, a Non-GAAP financial measure, as realized revenues per Boe less "all-in cash operating costs" per Boe. Management believes that this metric provides useful additional information to investors to assess the Company's operating margins in comparison to its peers, which may vary from company to company.

Non-GAAP Reconciliations

Adjusted Net Income

(Unaudited for All Periods)

	Three Months Ended					
	March 31, 2026		December 31, 2025		March 31, 2025	
	Total	Per share - diluted	Total	Per share - diluted	Total	Per share - diluted
Net income (loss)	$(220,591,482)	$ (1.06)	$ (12,845,294)	$ (0.06)	$ 9,110,738	$ 0.05
Share-based compensation	1,524,808	0.01	1,474,560	0.01	1,690,958	0.01
Ceiling test impairment	162,086,257	0.78	35,913,116	0.17	—	—
Unrealized loss (gain) on change in fair value of derivatives	76,954,914	0.37	(14,753,449)	(0.07)	375,196	—
Transaction costs - A&D	—	—	25,000	—	1,776	—
Tax impact on adjusted items	(12,557,544)	(0.06)	(6,213,517)	(0.03)	(500,646)	(0.01)
Adjusted Net Income	7,416,953	$ 0.04	3,600,416	$ 0.02	10,678,022	$ 0.05
Diluted Weighted-Average Shares Outstanding	208,558,546		207,233,067		201,072,594	
Adjusted Net Income per Diluted Share	$ 0.04		$ 0.02		$ 0.05	

Non-GAAP Reconciliations (cont.)

Adjusted EBITDA

(Unaudited for All Periods)

	Three Months Ended				
	March 31, 2026	December 31, 2025	September 30, 2025	June 30, 2025	March 31, 2025
Net income (loss)	$ (220,591,482)	$ (12,845,294)	$ (51,631,530)	$ 20,634,887	$ 9,110,738
Interest expense, net	8,529,080	9,065,509	9,978,067	11,687,746	9,408,728
Unrealized loss (gain) on change in fair value of derivatives	76,954,914	(14,753,449)	2,141,925	(13,970,211)	375,196
Ceiling test impairment	162,086,257	35,913,116	72,912,330	—	—
Income tax (benefit) expense	(11,988,413)	(3,800,401)	(12,800,947)	6,107,425	3,041,177
Depreciation, depletion and amortization	21,405,948	23,002,908	25,225,345	25,569,914	22,615,983
Asset retirement obligation accretion	395,496	390,892	390,563	382,251	326,549
Transaction costs - A&D	—	25,000	10	1,000	1,776
Share-based compensation	1,524,808	1,474,560	1,618,600	1,351,839	1,690,958
Loss (gain) on disposal of assets	—	(60,855)	(105,642)	(155,293)	(124,610)
Other income	(5,837)	(29,582)	—	(150,770)	(8,942)
Adjusted EBITDA	$ 38,310,771	$ 38,382,404	$ 47,728,721	$ 51,458,788	$ 46,437,553
Adjusted EBITDA Margin [1]	52 %	57 %	61 %	62 %	59 %

1. Adjusted EBITDA Margin is Adj. EBITDA divided by oil, natural gas, and natural gas liquids revenue.

Non-GAAP Reconciliations (cont.)

Adjusted Free Cash Flow

	(Unaudited for All Periods) Three Months Ended				
	March 31, 2026	December 31, 2025	September 30, 2025	June 30, 2025	March 31, 2025
Net Cash Provided by Operating Activities	$ 25,894,701	$ 44,688,823	$ 44,492,325	$ 33,297,251	$ 28,371,008
Adjustments - Condensed Statements of Cash Flows					
Changes in operating assets and liabilities	4,491,388	(14,727,429)	(6,086,921)	8,312,480	9,784,999
Transaction costs - A&D	—	25,000	10	1,000	1,776
Income tax expense (benefit) - current	95,587	51,311	39,772	147,460	136,394
Capital expenditures	(34,505,509)	(24,343,200)	(24,589,282)	(16,827,513)	(32,451,531)
Proceeds from divestiture of oil and natural gas properties	4,266,479	—	100	—	—
Credit loss expense	—	—	(907)	(205)	(17,917)
Other income	(5,837)	(29,582)	—	(150,770)	(8,942)
Adjusted Free Cash Flow	$ 236,809	$ 5,664,923	$ 13,855,097	$ 24,779,703	$ 5,815,787

	(Unaudited for All Periods) Three Months Ended				
	March 31, 2026	December 31, 2025	September 30, 2025	June 30, 2025	March 31, 2025
Adjusted EBITDA	$ 38,310,771	$ 38,382,404	$ 47,728,721	$ 51,458,788	$ 46,437,553
Net interest expense (excluding amortization of deferred financing costs)	(7,834,932)	(8,374,281)	(9,284,442)	(9,851,572)	(8,170,235)
Capital expenditures	(34,505,509)	(24,343,200)	(24,589,282)	(16,827,513)	(32,451,531)
Proceeds from divestiture of oil and natural gas properties	4,266,479	—	100	—	—
Adjusted Free Cash Flow	$ 236,809	$ 5,664,923	$ 13,855,097	$ 24,779,703	$ 5,815,787

Non-GAAP Reconciliations (cont.)

Leverage Ratio (Current Period End)

(Unaudited)

	Three Months Ended June 30, 2025	Three Months Ended September 30, 2025	Three Months Ended December 31, 2025	Three Months Ended March 31, 2026	Last Four Quarters
Consolidated EBITDAX Calculation:					
Net Income (Loss)	$ 20,634,887	$ (51,631,530)	$ (12,845,294)	$ (220,591,482)	$ (264,433,419)
Plus: Consolidated interest expense	11,687,746	9,978,067	9,065,509	8,529,080	39,260,402
Plus: Income tax provision (benefit)	6,107,425	(12,800,947)	(3,800,401)	(11,988,413)	(22,482,336)
Plus: Depreciation, depletion and amortization	25,569,914	25,225,345	23,002,908	21,405,948	95,204,115
Plus: non-cash charges reasonably acceptable to Administrative Agent	(12,236,121)	77,063,418	23,025,119	240,961,475	328,813,891
Consolidated EBITDAX	**$ 51,763,851**	**$ 47,834,353**	**$ 38,447,841**	**$ 38,316,608**	**$ 176,362,653**
Plus: Pro Forma Acquired Consolidated EBITDAX	—	—	—	—	—
Less: Pro Forma Divested Consolidated EBITDAX	—	—	—	—	—
Pro Forma Consolidated EBITDAX	**$ 51,763,851**	**$ 47,834,353**	**$ 38,447,841**	**$ 38,316,608**	**$ 176,362,653**
Non-cash charges reasonably acceptable to Administrative Agent:					
Asset retirement obligation accretion	$ 382,251	$ 390,563	$ 390,892	$ 395,496	
Unrealized loss (gain) on derivative assets	(13,970,211)	2,141,925	(14,753,449)	76,954,914	
Ceiling test impairment	—	72,912,330	35,913,116	162,086,257	
Share-based compensation	1,351,839	1,618,600	1,474,560	1,524,808	
Total non-cash charges reasonably acceptable to Administrative Agent	$ (12,236,121)	$ 77,063,418	$ 23,025,119	$ 240,961,475	

	As of March 31, 2026	Corresponding Leverage Ratio
Leverage Ratio Covenant:		
Revolving line of credit	$ 426,000,000	2.42
Notes payable	—	—
Deferred payment	—	—
Capital lease obligations	1,173,807	—
Consolidated Total Debt	427,173,807	2.42
Pro Forma Consolidated EBITDAX	176,362,653	
Leverage Ratio	**2.42**	
Maximum Allowed	≤ 3.00x	

Leverage Ratio (Comparative Period End)

(Unaudited)

	Three Months Ended June 30, 2024	Three Months Ended September 30, 2024	Three Months Ended December 31, 2024	Three Months Ended March 31, 2025	Last Four Quarters
Consolidated EBITDAX Calculation:					
Net Income (Loss)	$ 22,418,994	$ 33,878,424	$ 5,657,519	$ 9,110,738	$ 71,065,675
Plus: Consolidated interest expense	10,801,194	10,610,539	9,987,731	9,408,728	40,808,192
Plus: Income tax provision (benefit)	6,820,485	10,087,954	1,803,629	3,041,177	21,753,245
Plus: Depreciation, depletion and amortization	24,699,421	25,662,123	24,548,849	22,615,983	97,526,376
Plus: non-cash charges acceptable to Administrative Agent	1,664,064	(26,228,108)	8,994,957	2,392,703	(13,176,384)
Consolidated EBITDAX	**$ 66,404,158**	**$ 54,010,932**	**$ 50,992,685**	**$ 46,569,329**	**$ 217,977,104**
Plus: Pro Forma Acquired Consolidated EBITDAX	10,329,116	7,838,163	5,244,078	7,392,359	30,803,716
Less: Pro Forma Divested Consolidated EBITDAX	(469,376)	(600,460)	77,819	8,855	(983,162)
Pro Forma Consolidated EBITDAX	**$ 76,263,898**	**$ 61,248,635**	**$ 56,314,582**	**$ 53,970,543**	**$ 247,797,658**
Non-cash charges acceptable to Administrative Agent:					
Asset retirement obligation accretion	$ 352,184	$ 354,195	$ 323,085	$ 326,549	
Unrealized loss (gain) on derivative assets	(765,898)	(26,614,390)	6,999,552	375,196	
Share-based compensation	2,077,778	32,087	1,672,320	1,690,958	
Total non-cash charges acceptable to Administrative Agent	$ 1,664,064	$ (26,228,108)	$ 8,994,957	$ 2,392,703	

	As of March 31, 2025	Corresponding Leverage Ratio
Leverage Ratio Covenant:		
Revolving line of credit	$ 460,000,000	1.86
Lime Rock deferred payment	10,000,000	0.04
Consolidated Total Debt	$ 470,000,000	1.90
Pro Forma Consolidated EBITDAX	247,797,658	
Leverage Ratio	**1.90**	
Maximum Allowed	≤ 3.00x	

Non-GAAP Reconciliations (cont.)

Leverage Ratio (Summary of Other Periods)

	(Unaudited) Last Four Quarters Ended				
	March 31, 2026	December 31, 2025	September 30, 2025	June 30, 2025	March 31, 2025
Consolidated EBITDAX Calculation:					
Net Income (Loss)	$ (264,433,419)	$ (34,731,199)	$ (16,228,386)	$ 69,281,568	$ 71,065,675
Plus: Consolidated interest expense	39,260,402	40,140,050	41,062,272	41,694,744	40,808,192
Plus: Income tax provision (benefit)	(22,482,336)	(7,452,746)	(1,848,716)	21,040,185	21,753,245
Plus: Depreciation, depletion and amortization	95,204,115	96,414,150	97,960,091	98,396,869	97,526,376
Plus: non-cash charges acceptable to Administrative Agent	328,813,891	90,245,119	76,214,957	(27,076,569)	(13,176,384)
Consolidated EBITDAX	**$ 176,362,653**	**$ 184,615,374**	**$ 197,160,218**	**$ 203,336,797**	**$ 217,977,104**
Plus: Pro Forma Acquired Consolidated EBITDAX	—	7,392,359	12,636,437	20,474,600	30,803,716
Less: Pro Forma Divested Consolidated EBITDAX	—	8,855	86,674	(513,786)	(983,162)
Pro Forma Consolidated EBITDAX	**$ 176,362,653**	**$ 192,016,588**	**$ 209,883,329**	**$ 223,297,611**	**$ 247,797,658**

	As of March 31, 2026	As of December 31, 2025	As of September 30, 2025	As of June 30, 2025	As of March 31, 2025
Leverage Ratio Covenant:					
Revolving line of credit	$ 426,000,000	$ 420,000,000	$ 428,000,000	$ 448,000,000	$ 460,000,000
Notes payable	—	505,752	1,001,829		
Estimated deferred payment	—	—	10,000,000	10,000,000	10,000,000
Capital lease obligations	1,173,807	1,323,710	1,275,826		
Consolidated Total Debt	427,173,807	421,829,462	440,277,655	458,000,000	470,000,000
Pro Forma Consolidated EBITDAX	176,362,653	192,016,588	209,883,329	223,297,611	247,797,658
Leverage Ratio	**2.42**	**2.20**	**2.10**	**2.05**	**1.90**
Maximum Allowed	≤ 3.00x	≤ 3.00x	≤ 3.00x	≤ 3.00x	≤ 3.00x

Non-GAAP Reconciliations (cont.)

Adjusted Cash Flow from Operations (ACFFO)

	(Unaudited for All Periods) Three Months Ended		
	March 31, 2026	December 31, 2025	March 31, 2025
Net Cash Provided by Operating Activities	$ 25,894,701	$ 44,688,823	$ 28,371,008
Changes in operating assets and liabilities	4,491,388	(14,727,429)	9,784,999
Adjusted Cash Flow from Operations	$ 30,386,089	$ 29,961,394	$ 38,156,007

Cash Return on Capital Employed (CROCE)

	As of and for the twelve months ended		
	December 31, 2025	December 31, 2024	December 31, 2023
Total long term debt (i.e. revolving line of credit)	$420,000,000	$385,000,000	$425,000,000
Total stockholders' equity	836,275,746	858,639,982	786,582,900
Average debt	$402,500,000	$405,000,000	$420,000,000
Average stockholders' equity	847,457,864	822,611,441	723,843,146
Average debt and stockholders' equity	$1,249,957,864	$1,227,611,441	$1,143,843,146
Net Cash Provided by Operating Activities	$150,849,407	$194,423,712	$198,170,459
Less change in WC (Working Capital)	2,716,871	(888,089)	1,180,748
Adjusted Cash Flows From Operations (ACFFO)	$148,132,536	$195,311,801	$196,989,711
CROCE (ACFFO)/(Average D+E)	11.9 %	15.9 %	17.2 %

G&A Reconciliations

	(Unaudited for All Periods) Three Months Ended		
	March 31, 2026	December 31, 2025	March 31, 2025
General and administrative expense (G&A)	$ 7,438,778	$ 8,030,310	$ 8,619,976
Shared-based compensation	1,524,808	1,474,560	1,690,958
G&A excluding share-based compensation	$ 5,913,970	$ 6,555,750	$ 6,929,018
Transaction costs - A&D	—	25,000	1,776
G&A excluding share-based compensation and transaction costs	$ 5,913,970	$ 6,530,750	$ 6,927,242

PV-10

	Oil (Bbl)	Gas (Mcf)	Natural Gas Liquids (Bbl)	Net (Boe)	PV-10
Balance, December 31, 2024	80,904,071	149,817,162	28,303,085	134,176,684	$ 1,462,827,136
Purchase of minerals in place	9,915,483	10,067,543	2,373,336	13,966,743	
Extensions, discoveries and improved recovery	7,281,553	10,624,783	2,133,786	11,186,136	
Sales of minerals in place	—	—	—	—	
Production	(4,841,164)	(6,980,958)	(1,387,818)	(7,392,476)	
Revisions of previous quantity estimates	(2,939,895)	12,652,046	2,171,955	1,340,734	
Balance, December 31, 2025	90,320,048	176,180,576	33,594,344	153,277,821	$ 1,318,208,128

Non-GAAP Reconciliations (cont.)

All-In Cash Operating Costs

(Unaudited for All Periods)

	Three Months Ended			Trailing Twelve Months Ended	
	March 31, 2026	December 31, 2025	March 31, 2025	March 31, 2026	December 31, 2025
All-In Cash Operating Costs:					
Lease operating expenses (including workovers)	$ 18,122,344	$ 18,911,801	$ 19,677,552	$ 77,798,598	$ 79,353,806
G&A excluding share-based compensation	5,913,970	6,555,750	6,929,018	24,777,571	25,792,619
Net interest expense (excluding amortization of deferred financing costs)	7,834,932	8,374,281	8,170,235	35,345,227	35,680,530
Operating lease expense	175,091	175,090	175,091	700,362	700,362
Oil and natural gas production taxes	3,553,891	3,224,183	3,584,455	14,281,668	14,312,232
Ad valorem taxes	2,202,537	2,279,266	1,532,108	8,577,015	7,906,586
Gathering, transportation and processing costs	117,049	121,097	203,612	498,524	585,087
All-in cash operating costs	$ 37,919,814	$ 39,641,468	$ 40,272,071	$ 161,978,965	$ 164,331,222
Boe	1,741,581	1,886,755	1,655,259	7,478,797	7,392,476
All-in cash operating costs per Boe	$ 21.77	$ 21.01	$ 24.33	$ 21.66	$ 22.23

Cash Operating Margin

(Unaudited for All Periods)

	Three Months Ended			Trailing Twelve Months Ended	
	March 31, 2026	December 31, 2025	March 31, 2025	March 31, 2026	December 31, 2025
Cash Operating Margin					
Realized revenues per Boe	$ 42.30	$ 35.45	$ 47.78	$ 40.35	$ 41.55
All-in cash operating costs per Boe	21.77	21.01	24.33	21.66	22.23
Cash Operating Margin per Boe	$ 20.53	$ 14.44	$ 23.45	$ 18.69	$ 19.32