INFINITY

Second Quarter 2026 Earnings Call Presentation

August 2026

Disclaimer

Forward-Looking Statements. This presentation contains “forward-looking statements” that express the Company’s opinions, expectations, beliefs, plans, objectives, assumptions or projections regarding future events or future results, in contrast with statements that reflect historical facts. All statements, other than statements of historical fact, included in this presentation regarding the Company’s strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management, future commodity prices, future production targets, leverage targets or debt repayment, hedging strategy, future capital spending plans, capital efficiency, our ability to pay future dividends and make share repurchases, expected drilling and completions plans and projected well costs, among other similar statements, are forward-looking statements. When used in this presentation, words such as “may,” “assume,” “forecast,” “could,” “should,” “will,” “plan,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “project,” “target,” “outlook,” “guidance,” “budget” and similar expressions are used to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management’s current beliefs, based on currently available information, as to the outcome and timing of future events at the time such statements were made. Such statements are subject to a number of assumptions, risks and uncertainties, including those incident to the development, production, gathering and sale of oil, natural gas and NGLs, most of which are difficult to predict and many of which are beyond the control of the Company. These include, but are not limited to, our failure to realize, in full or at all, the anticipated benefits of capital raising transactions and acquisitions, including synergies; commodity price volatility; inflation; lack of availability and cost of drilling, completion and production equipment and services; supply chain disruption; project construction delays; environmental risks; drilling, completion and other operating risks; lack of availability or capacity of midstream gathering and transportation infrastructure; regulatory changes; the uncertainty inherent in estimating reserves and in projecting future rates of production, cash flow and access to capital; the timing of development expenditures; the concentration of the Company’s operations in the Appalachian Basin; difficult and adverse conditions in the domestic and global capital and credit markets; impacts of geopolitical events and world health events, including trade wars; the impacts of recently enacted legislation; lack of transportation and storage capacity as a result of oversupply, government regulations or other factors; potential financial losses or earnings reductions resulting from the Company’s commodity price risk management program or any inability to manage its commodity risks; failure to realize expected value creation from property acquisitions and trades; weather related risks; competition in the oil and natural gas industry; loss of production and leasehold rights due to mechanical failure or depletion of wells and the Company’s inability to re-establish production; the Company’s ability to service its indebtedness; political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, armed conflict, political instability and civil unrest, including instability in the Middle East, Venezuela and Mexico and other sustained military campaigns, the armed conflict in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage; evolving cybersecurity risks such as those involving unauthorized access, denial-of-service attacks, third-party service provider failures, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, social engineering, physical breaches or other actions; technological advancements, including artificial intelligence and its application in our industry; risks related to the Company’s ability to expand its business, including through the recruitment and retention of qualified personnel; and the other risks described under the heading “Risk Factors” in the Company’s filings with the U.S. Securities and Exchange Commission (the “SEC”), including its most recent Annual Report on Form 10-K and any subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

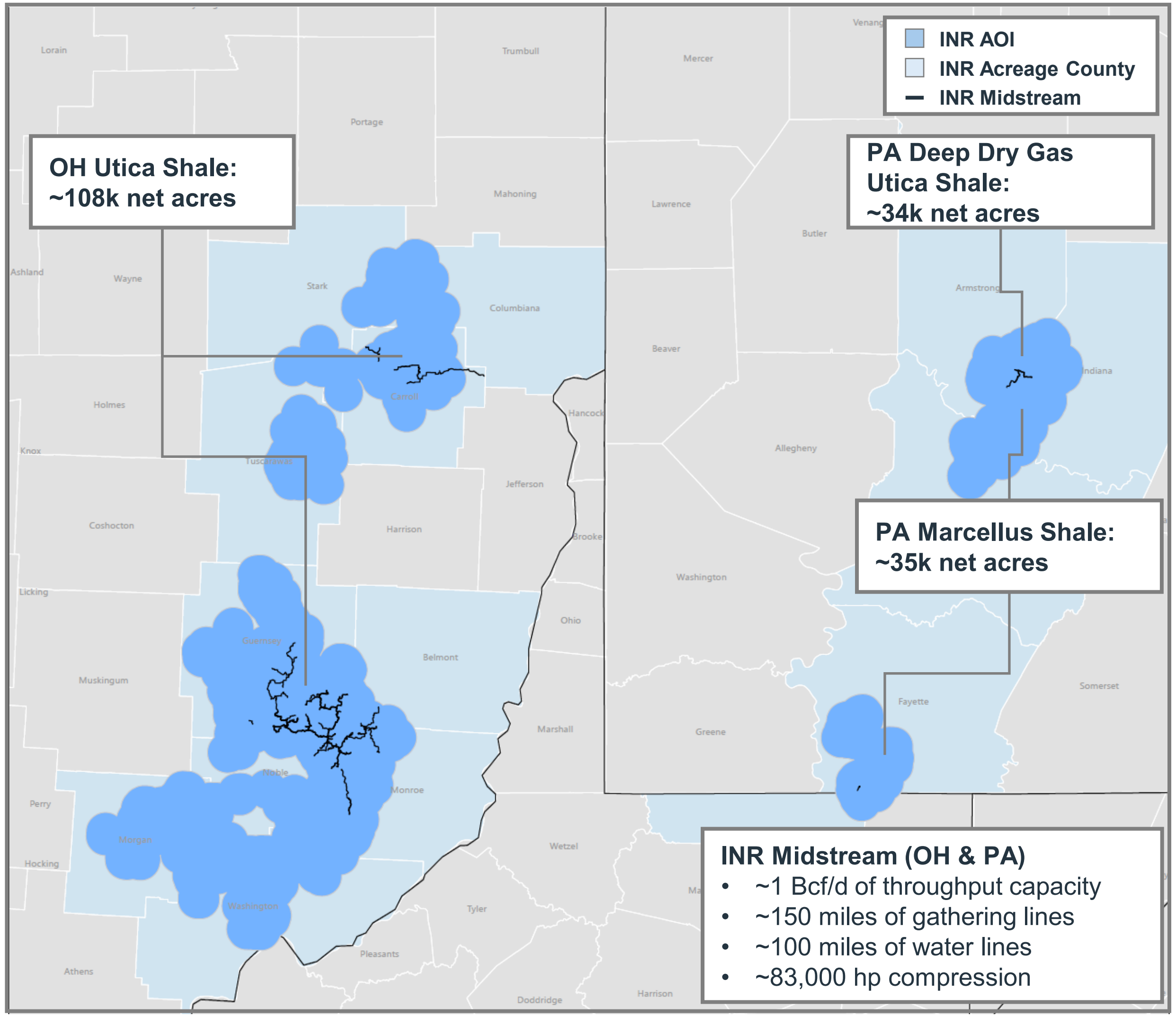
As a result, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements. Therefore, these forward-looking statements are not a guarantee of the Company’s performance, and you should not place undue reliance on such statements. All forward-looking statements, expressed or implied, included in this presentation are expressly qualified in their entirety by this cautionary statement. Any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except to the extent required by law.

Reserves. The Company’s proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, the Company’s reserve and PV-10 estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered. You should not assume that the present values referred to in this presentation represent the actual current market value of our oil, natural gas and NGL reserves. You are urged to consider closely the oil and natural gas disclosures in the Company’s filings with the SEC, including its most recent Annual Report on Form 10-K.

Non-GAAP Measures. This presentation includes certain non-GAAP financial measures, such as Adjusted EBITDAX, Adjusted EBITDAX Margin, PV-10, Capital Efficiency Ratio, F&D, DROI, Net Leverage and Net Debt. Because not all companies calculate non-GAAP financial measures identically (or at all), the non-GAAP financial measures included herein may not be comparable to other similarly titled measures used by other companies. Further, such non-GAAP financial information should not be considered as a substitute for the historical financial information prepared in accordance with GAAP included herein or provided in connection herewith. Please see the appendix of this presentation for definitions and reconciliations of such non-GAAP financial measures.

Infinity Natural Resources Overview

High growth, low cost, vertically integrated E&P focused on the development of balanced inventory



Infinity Natural Resources (NYSE: INR)

Market Capitalization[1]	**$823 million**
Enterprise Value[1]	**$1.7 billion**
Net Leverage[2][4]	1.1x
Liquidity[3]	$901 million
Operating / Financial Statistics	
Net Horizon Acreage	~177,000
Inventory (#) / Inventory Life (yrs)[5]	400+ / ~12 years
2Q 2026 Production	348 MMcfe/d
2Q 2026 Adj. EBITDAX Margin[4]	$3.62/mcfe
2025 Capital Efficiency / Peer Avg.[4]	3.5x / 1.6x
Midstream Capacity	~1.0 Bcf/d
2026E Guidance	
Net Production (MMcfe/d)	345 – 375
Net Liquids Production (Mbbls/d)	18 – 20
Annual Production Growth[6]	70%
Development CapEx ($MM)[7]	$450 - $500
Operated Rigs	2

1. Equity market capitalization and enterprise value based on August 7, 2026 share price of $12.98 and 63.4 million total shares outstanding. Enterprise value calculation uses total debt and preferred balances excluding the impact of issuance fees and associated expenses.
2. Net leverage is defined as total debt outstanding less cash and cash equivalents outstanding as of June 30, 2026 divided by annualized Adjusted EBITDAX for the quarter ending June 30, 2026.
3. Liquidity is defined as borrowing base availability plus cash and cash equivalents as of June 30, 2026.
4. Net leverage, Adjusted EBITDAX, Adjusted EBITDAX Margin and Capital efficiency are Non-GAAP measures. See appendix for additional details.
5. Based on a 2-rig pace.
6. Annual production growth is calculated based on the midpoint of INR's production guidance for the year ending 2026.
7. Development capex is defined as the combination of drilling and completion capital expenditures and midstream capital expenditures.

Why Own Infinity Natural Resources

"A differentiated Appalachian E&P combining rare production growth with an integrated, high-margin operating platform."

Balanced High-Quality Portfolio

- $3.4 Billion Economic Projects >2.0x DROI[1]
- Ohio Utica assets with exposure to oil-weighted, liquids-rich, and dry gas inventory
- Pennsylvania assets with exposure to stacked-pay Marcellus and Deep Utica inventory

Operational Flexibility

- Flexibility to allocate capital across oil, liquids-rich, and dry gas to the highest return opportunities
- Deep inventory enables cycle-driven capital allocation
- Enhances returns through commodity cycles

Expansive Midstream System

- Upstream & Midstream integration in PA and acquired OH assets
- Control over gathering, processing, and marketing
- Structurally competitive cost advantages
- Lower breakevens through scale and integrated midstream

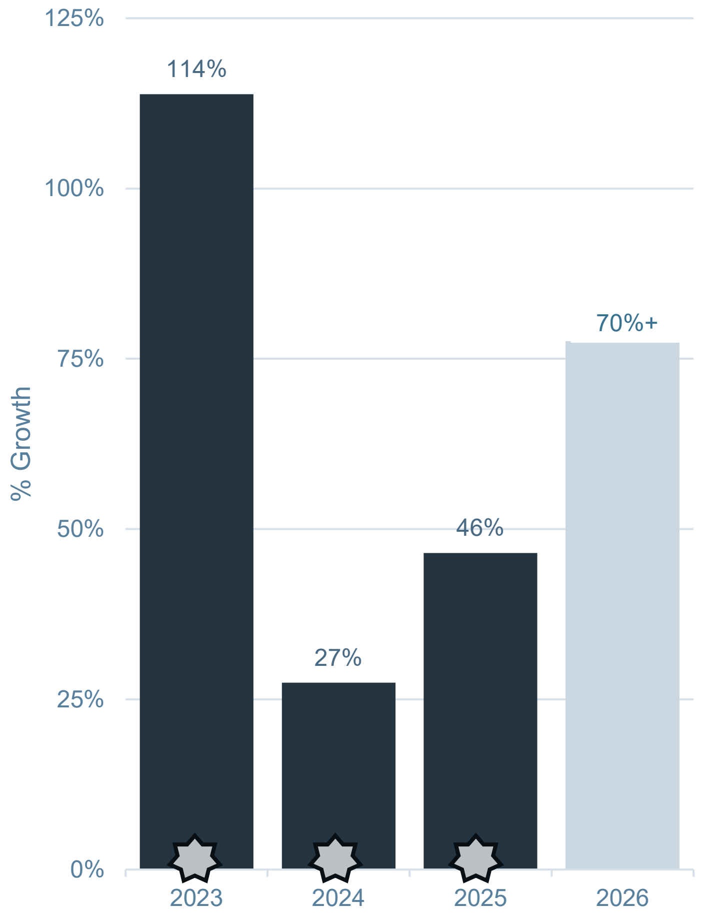
Basin-Leading Profitability

- Basin-leading Appalachian EBITDA margins per Mcfe
- Low F&D costs drive best-in-class capital efficiency
- High-margin resource base across the Utica and Marcellus

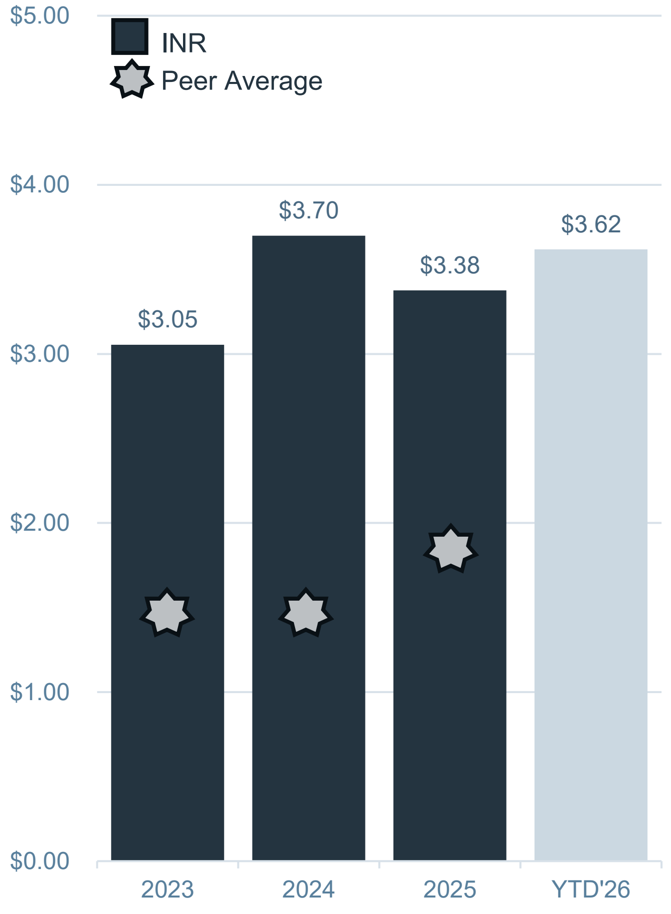
1. DROI is a non-GAAP measure. See appendix for additional details.

Best in Basin Growth, Margin and Capital Efficiency

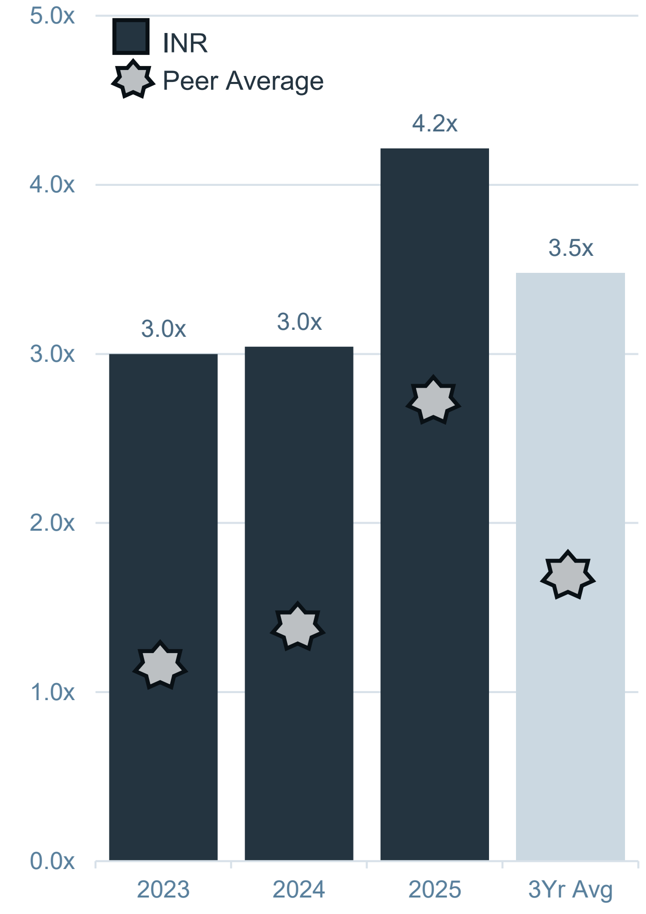
Net Production Growth *(MMcfe/d)*[1]



Adj. EBITDAX Margin[2] *($/Mcfe)*



Capital Efficiency[3] *(x)*



Note: Diamonds represent Appalachian peers' average, with peers being AR, CNX, EQT, GPOR, and RRC.

1. Net production for 2026 and annual production growth are calculated based on the midpoint of INR's production guidance for the year ending 2026.
2. Adjusted EBITDAX margin is a non-GAAP measure. For a reconciliation, please see the appendix. Peer average statistics were $1.52/mcfe, $1.54/mcfe, $1.93/mcfe for 2023, 2024, and 2025, respectively.
3. Capital Efficiency is a non-GAAP measure. Capital efficiency is calculated as the Adjusted EBITDAX margin for a period divided by the all-in F&D ($/mcfe) for a period. For a reconciliation, please see the appendix. Peer average statistics were 1.1x, 1.4x, 2.8x and 1.7x for 2023, 2024, 2025 and 3-year average, respectively.

Continued Execution: *Second Quarter 2026 Results*

	2Q26	2Q25
Total Production Volumes	348 *MMcfe/d*	199 *MMcfe/d*
Net Revenues	$171.0 *million*	$74.5 *million*
Operating Costs[(1)]	$36.2 *million*	$23.9 *million*
Adjusted EBITDAX[(2)]	$114.7 *million*	$49.6 *million*
Incurred Development Capital Expenditures	$129.1 *million*	$73.1 *million*
Net Leverage[(2)] (Net Debt / LQA Adj. EBITDAX)	1.1x	0.1x

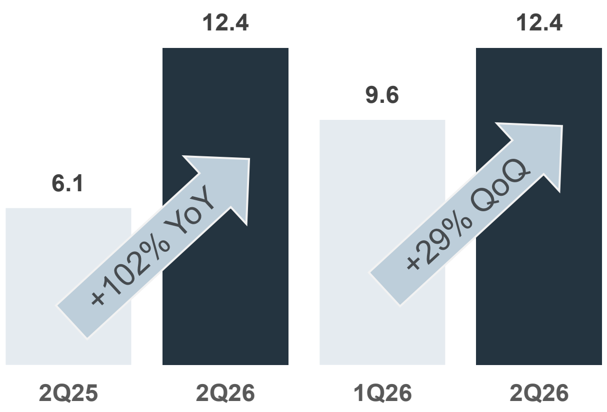
Key Highlights

- ***Increased net production and Adjusted EBITDAX by 75% and 131% year over year, respectively***
- ***Turned in Line 10 wells in Ohio during the second quarter***
  - 7 volatile oil Utica wells (3 TIL in late June)
  - 3 rich gas Utica wells (TIL in late June)
- ***Spudded 9 wells***
  - 1 deep dry gas Utica well, 2 dry gas Marcellus wells
  - 2 rich gas Utica wells
  - 4 volatile oil Utica wells
- ***Completed 10 wells***
  - 7 volatile oil Utica wells, 3 dry gas Marcellus wells
- Added ~1,100 net horizon acres during 2Q26
- Midstream expansion continuing as planned in Pennsylvania and on acquired Ohio assets
- Strong balance sheet supported by $901 million of liquidity

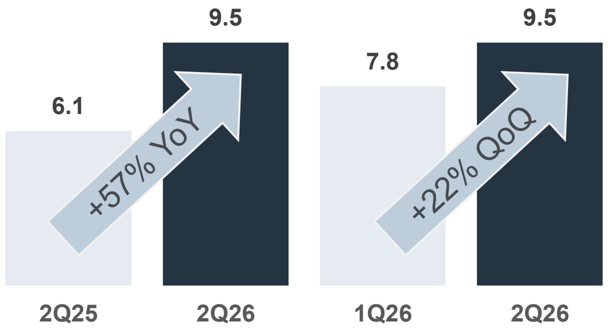
1. Operating costs exclude the impact of firm transportation costs. See management's discussion and analysis of financial condition and results of operations in the Company's Quarterly Report on Form 10-Q for further detail.
2. Adjusted EBITDAX and net leverage are non-GAAP measures. See appendix for additional details.

Increasing Production While Driving Costs Lower

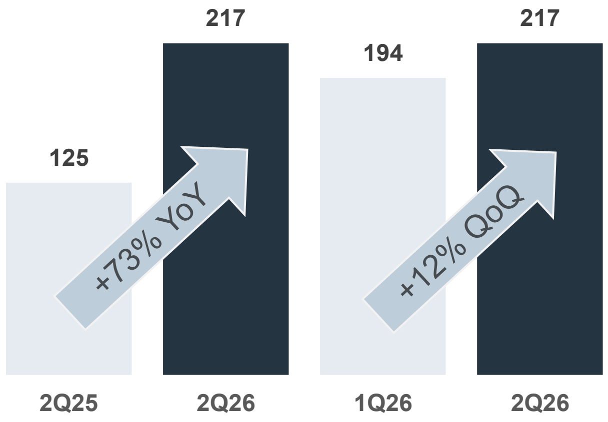
Oil Production (Mbbls/d)



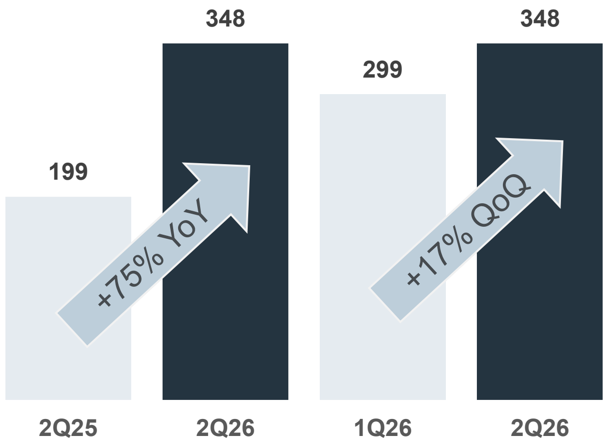
NGL Production (Mbbls/d)



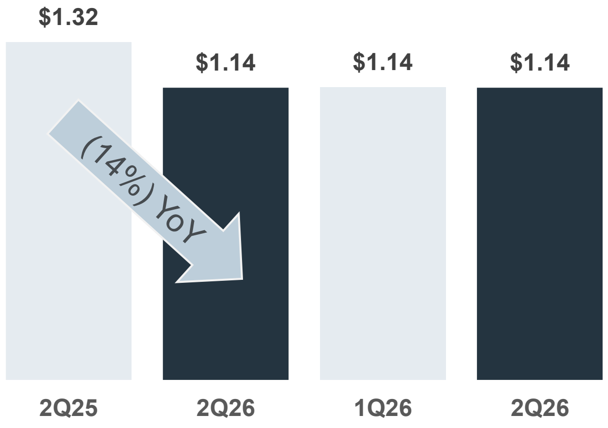
Nat. Gas Production (MMcfe/d)



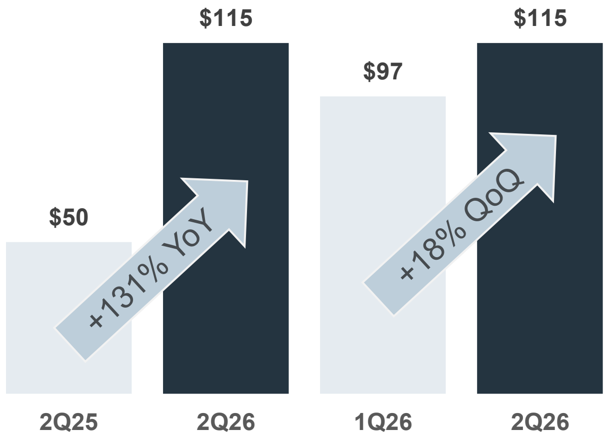
Total Production (MMcfe/d)



Operating Expenses ($/Mcfe)(1)(2)



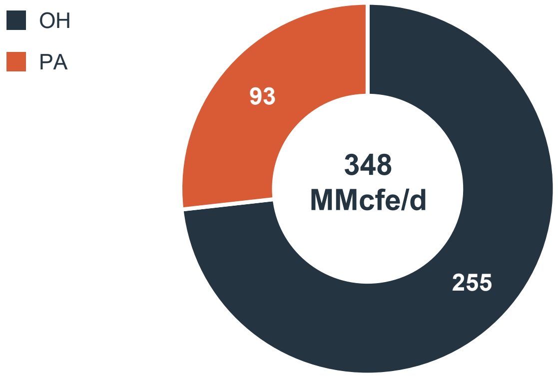
Adjusted EBITDAX ($MM)(2)



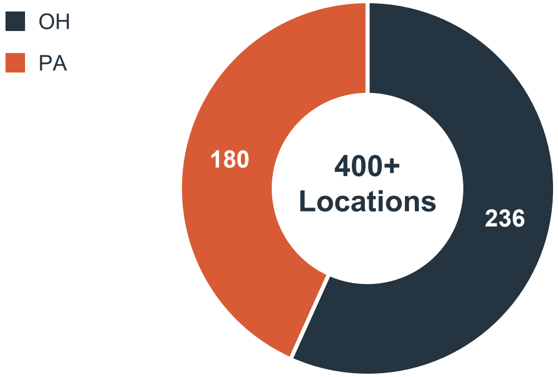
1. Operating expenses include LOE, GP&T, midstream opex, and production taxes. GP&T excludes firm transportation costs of approximately $7.5 million, or $0.24/Mcfe.
2. Adjusted EBITDAX and GP&T excluding firm transportation costs are non-GAAP measures. See appendix for additional details.

Balanced High Return Development Across All Hydrocarbons

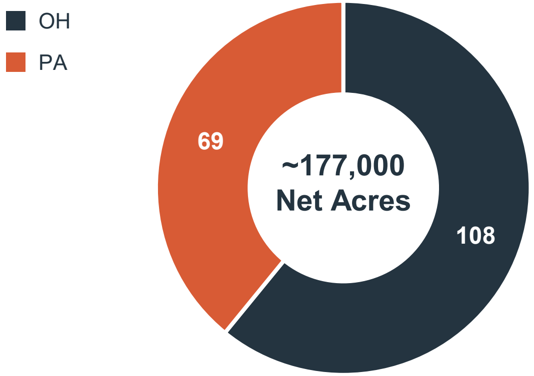
2Q26 Net Production (MMcfe/d)



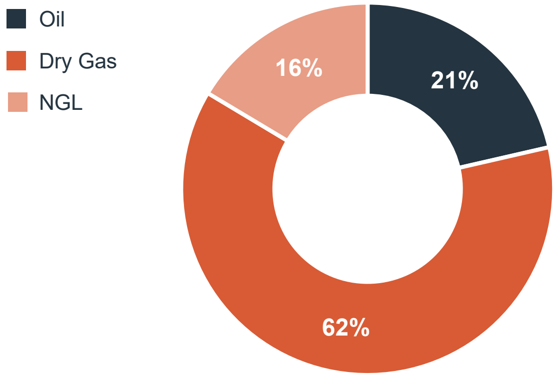
Location Count by State[1]



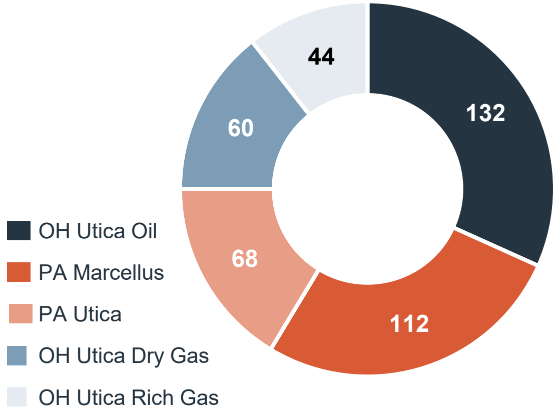
Net Horizon Acres by State (000's)



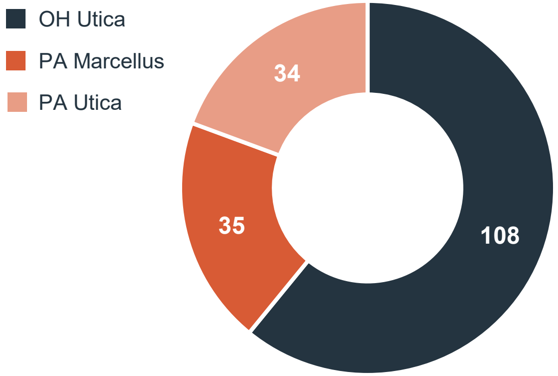
2Q26 Production Mix (%)



Location Count by Operating Area[1]



Net Horizon Acres by Reservoir (000's)

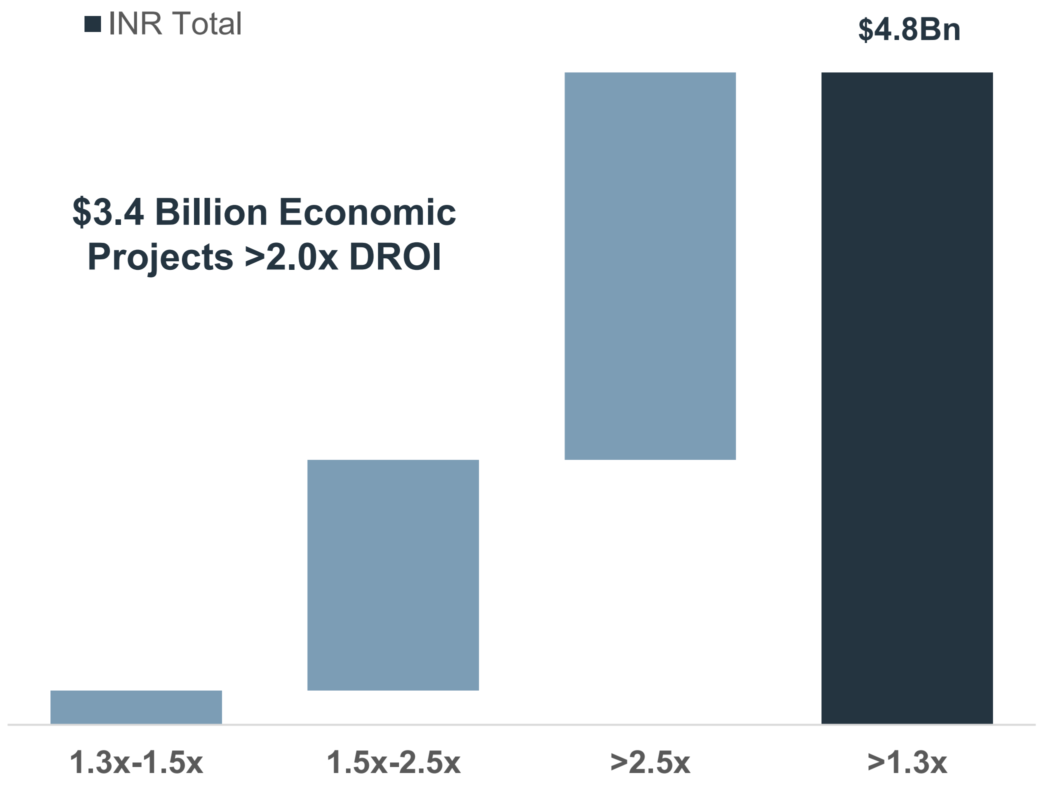


Assets are uniquely positioned providing high return resource exposure to oil, rich gas, and dry gas drilling inventory

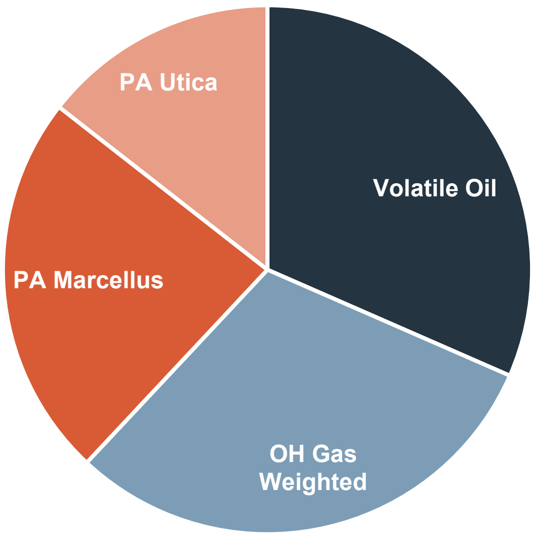
1. Location counts include all wells in process ("WIPs") and undeveloped locations

Expansive High DROI(x) Inventory Across Operating Areas

Economic Capital Projects by DROI[1]



Total Inventory Lateral Footage by Area



INR's highly economic inventory base spans across dry gas, rich gas, and oil phase windows

Note: All type curves reflect internal forecasts. Well costs and operating costs are internal projections. Revenue is based on $65/bbl WTI and $4.00/MMBtu Henry Hub

1. DROI is a non-GAAP measure. See appendix for additional details.

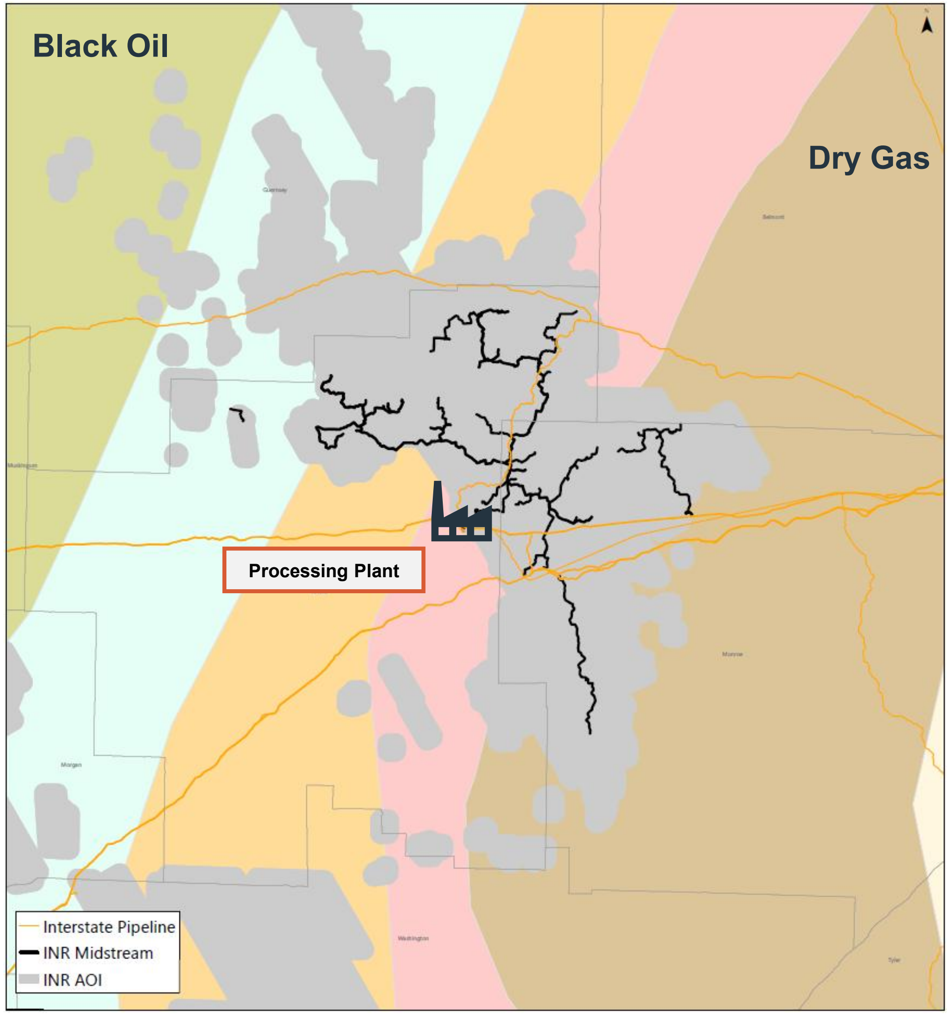
Expansive Company Owned Midstream System

Key Highlights

- ~1 Bcf/d of throughput capacity capable of supporting INR growth thru end of decade
- 70% of INR gross operated natural gas volumes flowing through owned system
- Increased system utilization by 30% since end of 1Q
- Vast operational reach supporting operating flexibility and development
- Significantly reduces well breakeven levels in Ohio and Pennsylvania

Ohio Compressor Station – Noble County

Southeastern Ohio Midstream System



Developing Assets Across Our Portfolio

	Volatile Oil Utica (OH)				Rich Gas Utica (OH)				Dry Gas Marcellus (PA)				Deep Dry Gas Utica (PA)				Total Company			
	2Q26	YTD	3Q26	2026E	2Q26	YTD	3Q26	2026E	2Q26	YTD	3Q26	2026E	2Q26	YTD	3Q26	2026E	2Q26	YTD	3Q26	2026E
Wells Spud																				
Gross Wells	4.0	7.0	4.0	18.0	2.0	2.0	6.0	14.0	2.0	6.0	-	6.0	1.0	1.0	-	1.0	9.0	16.0	10.0	39.0
Net Wells	3.7	5.7	3.4	14.0	1.2	1.2	2.3	6.6	2.0	6.0	-	6.0	1.0	1.0	-	1.0	7.9	13.9	5.7	27.6
Gross Lateral Footage (Mft)	46.0	89.0	87.0	311.0	19.0	19.0	79.0	159.0	28.0	91.0	-	91.0	10.0	10.0	-	10.0	103.0	209.0	166.0	571.0
Avg. Lateral Length (Mft)	11.5	12.7	21.8	17.3	9.5	9.5	13.2	11.4	14.0	15.2	-	15.2	10.0	10.0	-	10.0	11.4	13.1	16.6	14.6
Wells Completed																				
Gross Wells	7.0	15.0	-	19.0	-	3.0	3.0	11.0	3.0	3.0	3.0	6.0	-	-	1.0	1.0	10.0	21.0	7.0	37.0
Net Wells	5.7	13.5	-	16.9	-	1.7	1.8	5.2	3.0	3.0	3.0	6.0	-	-	1.0	1.0	8.7	18.2	5.8	29.1
Gross Lateral Footage (Mft)	89.0	199.0	-	286.0	-	53.0	30.0	152.0	47.0	47.0	44.0	91.0	-	-	10.0	10.0	136.0	299.0	84.0	539.0
Avg. Lateral Length (Mft)	12.7	13.3	-	15.1	-	17.7	10.0	13.8	15.7	15.7	14.7	15.2	-	-	10.0	10.0	13.6	14.2	12.0	14.6
Wells Turned-in-Line ("TIL")																				
Gross Wells	7.0	11.0	4.0	15.0	3.0	3.0	-	6.0	-	-	3.0	6.0	-	-	-	1.0	10.0	14.0	7.0	28.0
Net Wells	5.9	9.8	3.7	13.5	1.7	1.7	-	3.5	-	-	3.0	6.0	-	-	-	1.0	7.5	11.5	6.7	24.0
Gross Lateral Footage (Mft)	99.0	153.0	46.0	199.0	53.0	53.0	-	83.0	-	-	47.0	91.0	-	-	-	10.0	152.0	206.0	93.0	383.0
Avg. Lateral Length (Mft)	14.1	13.9	11.5	13.3	17.7	17.7	-	13.8	-	-	15.7	15.2	-	-	-	10.0	15.2	14.7	13.3	13.7

2026 program weighted towards Ohio development with near term focus on liquids-weighted projects

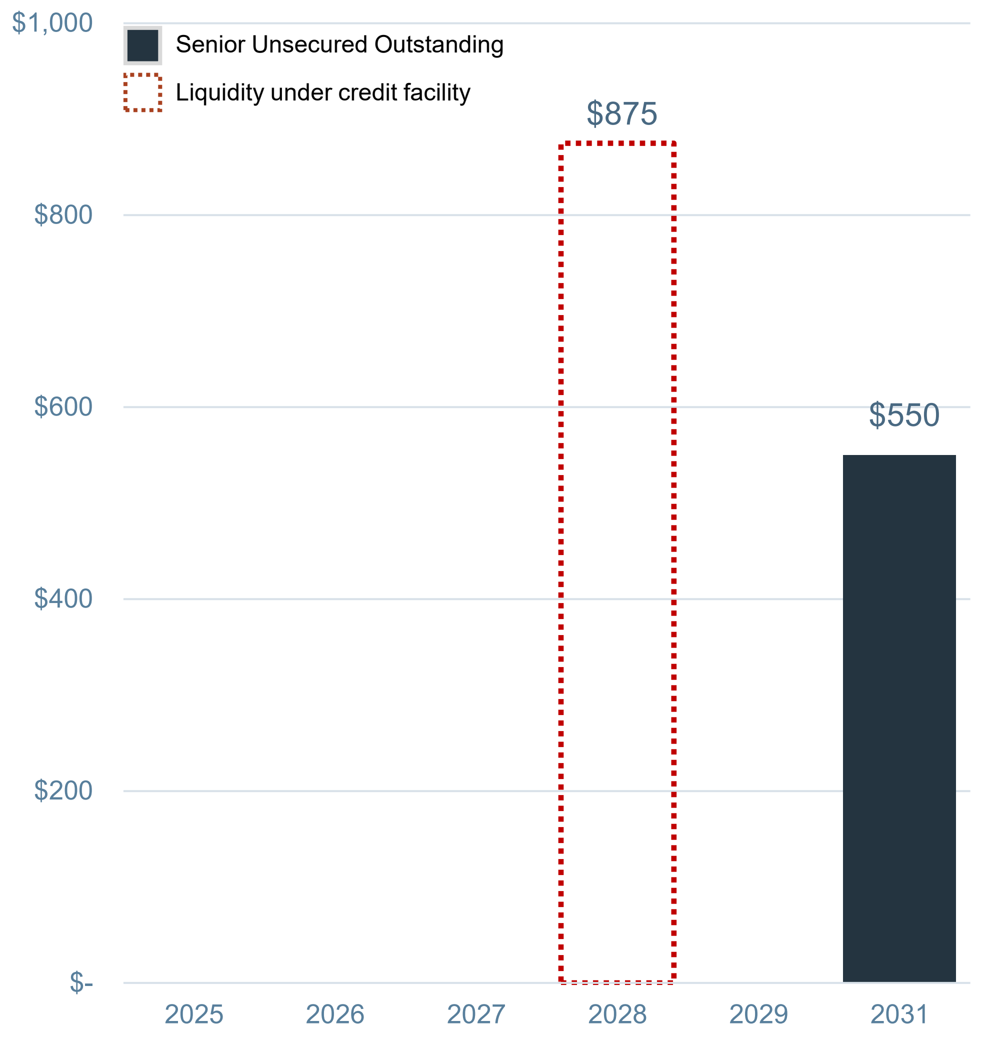
Note: Rich Gas Utica (OH) reflects the assets acquired from Antero.

Financial Strength Provides Strategic Flexibility

Key Points

- **Net leverage of 1.1x[(1)]**
- Target long term net leverage of less than 1.0x [(1)]
- No near-term debt maturities
- No borrowings outstanding under revolving credit facility
- Active hedge program moderates forecasted cash flow

Significant Liquidity with no Near-Term Maturities



1. Net leverage is defined as total debt outstanding less cash and cash equivalents outstanding as of June 30, 2026 divided by annualized Adjusted EBITDAX for the quarter ending June 30, 2026. Net leverage is a Non-GAAP measure. See appendix for additional details.

Appendix

2026 Outlook and Guidance

Net Production			
Total Net Production (Mmcfe/d)	345	–	375
Total Natural Gas Net Production (Mmcf/d)	235	–	255
Total Liquids Net Production (Mbbls/d)	18	–	20
Incurred Development Capital Expenditures[1]	$450	–	$500
Operated Rigs		~ 2 Rigs	
TILs (Gross)		~30 Wells	

1. Incurred Development Capital Expenditures includes well development and midstream capital.

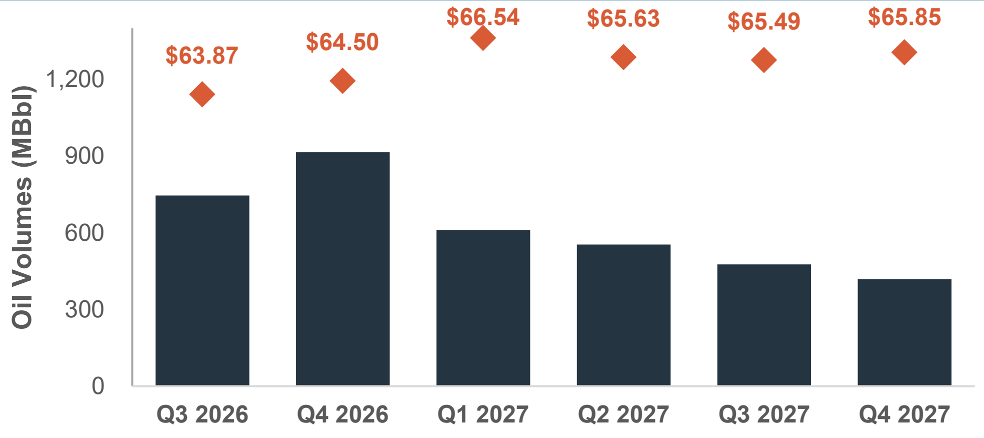
INR Hedge Position and Philosophy

INR seeks to mitigate commodity fluctuations by actively hedging its anticipated PDP and near-term development production to support cash management and leverage.

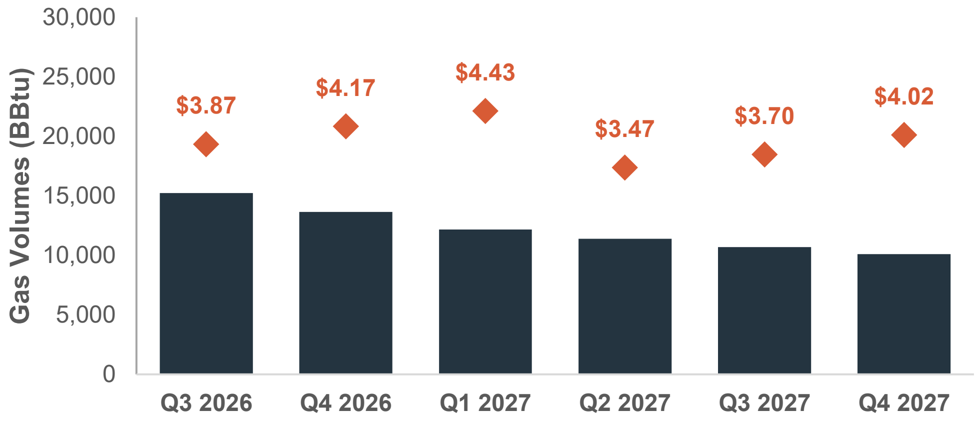
Hedging Overview

- INR actively hedges within its bank group to secure DROIs and maintain balance sheet strength
- INR is hedged approximately 78% on an equivalent basis for the remainder of 2026 at the midpoint of our guidance
- Recent hedging activity has focused on oil and C3+ trades for 2026 and 2027 tracking price increases following start of Iran conflict
- Primarily targeting swaps and collars

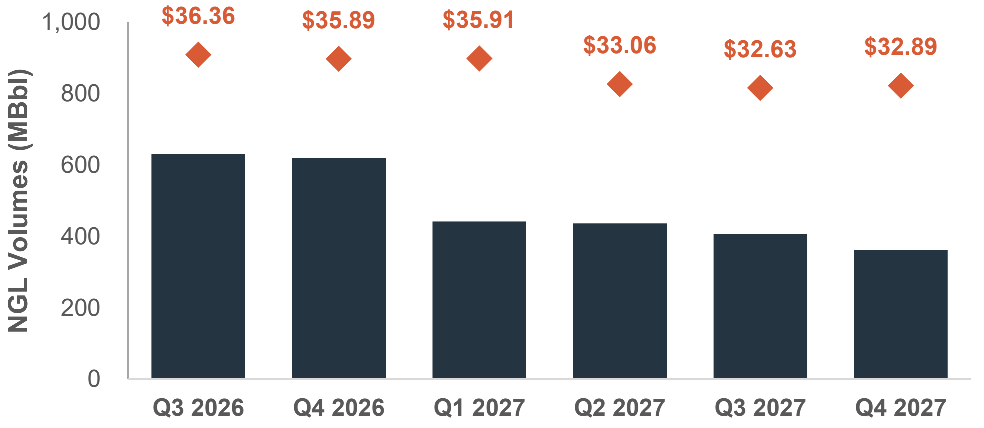
Oil Hedges



Natural Gas Hedges[(1)]



Natural Gas Liquids Hedges



Note: Hedge positions as of 6-Aug-26.
(1) Natural gas hedges represent Henry Hub trades volumes and price

Hedge Book Overview – As of 6-Aug-26

	FY 2026					FY 2027					FY 2028				
	Q1	Q2	Q3	Q4	2026	Q1	Q2	Q3	Q4	2027	Q1	Q2	Q3	Q4	2028
WTI Fixed Swaps															
Total Volume (MBbl)	634	613	679	801	2,726	458	454	411	387	1,710	249	227	211	197	884
Daily Volume (Bbl/d)	7,039	6,734	7,383	8,701	7,468	5,089	4,992	4,465	4,204	4,684	2,736	2,495	2,293	2,141	2,415
WAVG Swap Price ($ / Bbl)	$63.92	$63.71	$63.26	$63.71	$63.65	$65.39	$64.67	$64.78	$65.51	$65.08	$71.78	$71.09	$70.43	$69.91	$70.87
WTI Fixed Collars															
Total Volume (MBbl)	-	72	67	115	254	153	100	65	32	350	-	-	-	-	-
Daily Volume (Bbl/d)	-	791	728	1,250	696	1,700	1,099	707	348	959	-	-	-	-	-
WAVG Ceiling Price ($ / Bbl)	-	$78.00	$78.00	$78.00	$78.00	$84.60	$84.60	$84.60	$84.60	$84.60	-	-	-	-	-
WAVG Floor Price ($ / Bbl)	-	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	$70.00	-	-	-	-	-
Henry Hub Fixed Swaps															
Total Volume (BBtu)	16,061	16,040	15,230	13,644	60,975	12,167	11,390	10,688	10,089	44,334	9,450	8,990	8,670	8,260	35,370
Daily Volume (MMBtu/d)	178,456	176,264	165,543	148,304	167,055	135,189	125,165	116,174	109,663	121,463	103,846	98,791	94,239	89,783	96,639
WAVG Swap Price ($ / MMBtu)	$4.31	$3.62	$3.87	$4.17	$3.99	$4.43	$3.47	$3.70	$4.02	$3.91	$4.26	$3.29	$3.56	$3.90	$3.76
Dom South Basis Swaps															
Total Volume (BBtu)	12,276	11,347	10,137	9,065	42,825	7,131	3,140	3,320	3,280	16,871	2,940	2,780	2,670	2,540	10,930
Daily Volume (MMBtu/d)	136,400	124,692	110,185	98,533	117,329	79,233	34,505	36,087	35,652	46,222	32,308	30,549	29,022	27,609	29,863
WAVG Swap Price ($ / MMBtu)	($0.77)	($0.90)	($1.21)	($1.25)	($1.01)	($0.76)	($0.73)	($1.06)	($1.05)	($0.87)	($0.64)	($0.82)	($1.11)	($1.07)	($0.90)
Dom South Fixed Swaps															
Total Volume (BBtu)	795	2,001	4,544	4,296	11,636	3,220	2,696	2,360	2,096	10,372	-	-	-	-	-
Daily Volume (MMBtu/d)	8,833	21,989	49,391	46,696	31,879	35,778	29,626	25,652	22,783	28,416	-	-	-	-	-
WAVG Swap Price ($ / MMBtu)	$3.70	$2.83	$2.99	$3.12	$3.06	$3.60	$2.62	$2.60	$2.84	$2.96	-	-	-	-	-
Tetco M2 Basis Swaps															
Total Volume (BBtu)	473	461	451	436	1,821	366	413	403	385	1,566	1,280	1,228	1,210	1,155	4,873
Daily Volume (MMBtu/d)	5,256	5,066	4,902	4,739	4,989	4,067	4,533	4,375	4,185	4,290	14,066	13,489	13,152	12,554	13,313
WAVG Swap Price ($ / MMBtu)	($0.58)	($0.96)	($1.19)	($1.25)	($0.99)	($0.58)	($0.85)	($1.09)	($1.08)	($0.90)	($0.51)	($0.83)	($1.09)	($1.06)	($0.86)
REX Zone 3 Basis Swaps															
Total Volume (BBtu)	-	4,230	4,640	4,140	13,010	2,775	2,775	2,775	2,775	11,100	4,490	4,366	4,270	4,158	17,284
Daily Volume (MMBtu/d)	-	46,484	50,435	45,000	35,644	30,833	30,495	30,163	30,163	30,411	49,341	47,981	46,413	45,190	47,223
WAVG Swap Price ($ / MMBtu)	-	($0.41)	($0.48)	($0.31)	($0.40)	$0.13	($0.35)	($0.35)	($0.24)	($0.20)	$0.18	($0.28)	($0.33)	($0.21)	($0.16)

Hedge Book Overview – As of 6-Aug-26

	FY 2029					FY 2030					FY 2031				
	Q1	Q2	Q3	Q4	2029	Q1	Q2	Q3	Q4	2030	Q1	Q2	Q3	Q4	2031
WTI Fixed Swaps															
Total Volume (MBbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (Bbl/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Swap Price ($ / Bbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WTI Fixed Collars															
Total Volume (MBbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (Bbl/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Ceiling Price ($ / Bbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / Bbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Henry Hub Fixed Swaps															
Total Volume (BBtu)	7,780	7,600	7,420	7,170	29,970	6,800	6,630	6,530	6,350	26,310	-	-	-	-	-
Daily Volume (MMBtu/d)	86,444	83,516	80,652	77,935	82,110	75,556	72,857	70,978	69,022	72,082	-	-	-	-	-
WAVG Swap Price ($ / MMBtu)	$4.06	$3.14	$3.44	$3.80	$3.61	$4.02	$3.10	$3.37	$3.73	$3.56	-	-	-	-	-
Dom South Basis Swaps															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Swap Price ($ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dom South Fixed Swaps															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Swap Price ($ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2 Basis Swaps															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Swap Price ($ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REX Zone 3 Basis Swaps															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Swap Price ($ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Hedge Book Overview – As of 6-Aug-26

	FY 2026					FY 2027					FY 2028				
	Q1	Q2	Q3	Q4	2026	Q1	Q2	Q3	Q4	2027	Q1	Q2	Q3	Q4	2028
Ethane Fixed Swaps															
Total Volume (MGal)	2,441	2,440	2,294	2,137	9,312	1,902	1,854	1,750	1,610	7,116	-	-	-	-	-
Daily Volume (Gal/d)	27,122	26,813	24,935	23,228	25,512	21,133	20,374	19,022	17,500	19,496	-	-	-	-	-
WAVG Swap Price ($ / Gal)	$0.28	$0.27	$0.28	$0.29	$0.28	$0.27	$0.23	$0.23	$0.24	$0.24	-	-	-	-	-
Propane Fixed Swaps															
Total Volume (MGal)	5,259	9,696	13,976	13,832	42,763	9,619	9,415	8,725	7,747	35,506	-	-	-	-	-
Daily Volume (Gal/d)	58,433	106,549	151,913	150,348	117,159	106,878	103,462	94,837	84,207	97,277	-	-	-	-	-
WAVG Swap Price ($ / Gal)	$0.76	$0.74	$0.76	$0.76	$0.75	$0.77	$0.70	$0.70	$0.71	$0.72	-	-	-	-	-
Normal Butane Fixed Swaps															
Total Volume (MGal)	1,547	2,809	3,879	3,773	12,008	2,571	2,597	2,435	2,161	9,764	-	-	-	-	-
Daily Volume (Gal/d)	17,189	30,868	42,163	41,011	32,899	28,567	28,538	26,467	23,489	26,751	-	-	-	-	-
WAVG Swap Price ($ / Gal)	$0.87	$0.91	$0.93	$0.92	$0.91	$0.94	$0.84	$0.83	$0.84	$0.86	-	-	-	-	-
IsoButane Fixed Swaps															
Total Volume (MGal)	951	1,976	2,893	2,944	8,764	2,092	2,027	1,872	1,657	7,648	-	-	-	-	-
Daily Volume (Gal/d)	10,567	21,714	31,446	32,000	24,011	23,244	22,275	20,348	18,011	20,953	-	-	-	-	-
WAVG Swap Price ($ / Gal)	$0.89	$0.95	$0.98	$0.94	$0.95	$0.97	$0.89	$0.87	$0.88	$0.91	-	-	-	-	-
Natural Gasoline Fixed Swaps															
Total Volume (MGal)	772	2,472	3,411	3,346	10,001	2,354	2,415	2,276	2,005	9,050	1,010	900	830	770	3,510
Daily Volume (Gal/d)	8,578	27,165	37,076	36,370	27,400	26,156	26,538	24,739	21,793	24,795	11,099	9,890	9,022	8,370	9,590
WAVG Swap Price ($ / Gal)	$1.40	$1.59	$1.54	$1.47	$1.52	$1.47	$1.39	$1.36	$1.35	$1.39	$1.42	$1.38	$1.36	$1.35	$1.38

Non-GAAP Reconciliations and Definitions

Adjusted EBITDAX

Adjusted EBITDAX is defined as net income plus interest expense, other expense, income tax expense and benefit, depreciation, depletion, and amortization, unrealized gain (loss) on derivative instruments, net cash settlements received (paid) on derivatives, non-cash compensation expense and non-recurring transaction expenses. Adjusted EBITDAX is presented on our management's belief that this non-GAAP measure is useful information to investors when comparing our operating performance, our ability to fund development activities and to service our incurred debt without regard to our financing methods, corporate form or capital structure. Our computations of Adjusted EBITDAX may differ from and may not be comparable to similarly titled measures of other companies.

Adjusted EBITDAX Margin is defined as Adjusted EBITDAX divided by total production.

Net Debt and Net Debt to Adjusted EBITDAX (or Net Leverage)

Net Debt is calculated by subtracting cash and cash equivalents from total debt. Net Debt is a non-GAAP measures which our management believes are also useful to investors when assessing our leverage since we have the ability to and may decide to use a portion of our cash and cash equivalents to retire debt. Our management uses this measures for that purpose.

Adjusted EBITDAX Reconciliation

	Three Months Ended			Twelve Months Ended,	
($ in thousands)	06/30/25	03/31/26	06/30/26	12/31/24	12/31/25
Net Income	$71,954	($6,343)	$112,909	$49,286	$63,959
Add:					
Interest expense, net	$1,360	$5,789	$14,733	$21,529	$9,667
Provision / (benefit) for income taxes	($604)	($348)	$548	$0	($4,858)
Depreciation, depletion and amortization	$23,652	$35,660	$44,414	$73,726	$103,750
Net cash settlements received / (paid) on deriv.	$2,778	($17,992)	($6,427)	$28,360	$12,214
Non-recurring transaction expenses	$331	$13,452	$3,035	$771	$1,601
Non-cash compensation expenses[1]	$2,293	$1,912	$3,003	$0	$133,053
Less:	$331				
(Gain) / loss on derivative instruments	($52,121)	$65,134	($57,542)	$22,047	($58,407)
Adjusted EBITDAX	**$ 49,641**	**$ 97,264**	**$ 114,673**	**$ 195,719**	**$ 260,978**

Note: Adjusted EBITDAX is a non-GAAP financial measure.

1. Includes stock-based compensation expense for equity awards related to general and administrative employees only.

Net Leverage (x)

	Three Months Ending				
($ in thousands)	06/30/25	09/30/25	12/31/25	03/31/26	06/30/26
Total debt outstanding	$ 34,378	$ 75,363	$ 150,847	$ 537,648	$ 538,150
Plus: Unamortized Issuance Fees	$ -	$ -	$ -	$ 12,352	$ 11,850
Less: Cash and cash equivalents	$ (6,282)	$ (4,572)	$ (64,049)	$ (72,983)	$ (25,883)
Net debt outstanding	$ 28,096	$ 70,791	$ 86,798	$ 477,017	$ 524,117
Quarter Ending Adjusted EBITDAX	$ 49,641	$ 60,049	$ 94,042	$ 97,264	$ 114,673
Last Quarter Annualized Adjusted EBITDAX[1]	$ 198,564	$ 240,196	$ 376,169	$ 389,056	$ 458,692
Net debt to LQA EBITDAX	0.1x	0.3x	0.2x	1.2x	1.1x

1. Represents adjusted EBITDAX for the three months shown on an annualized basis

Non-GAAP Reconciliations and Definitions

Proved Reserves Pre-Tax PV-10

Proved Reserves SEC PV-10 represents the estimated present value of the future cash flows less future development and production costs from our proved and probable reserves before income taxes discounted using a 10% discount rate. PV-10 of proved reserves generally differs from the standardized measure of discounted future net cash flows from production of proved oil and natural gas reserves (the "Standardized Measure"), the most directly comparable GAAP financial measure, because it does not include the effects of future income taxes, as is required under GAAP in computing the Standardized Measure. We believe that the presentation of a pre-tax PV-10 value provides relevant and useful information because it is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and natural gas companies. Because many factors that are unique to each company may impact the amount and timing of future income taxes, the use of PV-10 value provides greater comparability when evaluating oil and natural gas companies. The PV-10 value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of proved oil and gas reserves. However, the definition of PV-10 value as defined above may differ significantly from the definitions used by other companies to compute similar measures. As a result, the PV-10 value as defined may not be comparable to similar measures provided by other companies.

All-In Finding & Development Costs ("F&D")

All-In F&D is calculated by dividing total costs incurred (which includes the total acquisition, exploration and development costs incurred during the period related to the specified property or group of properties) by the sum of the extensions, discoveries, additions, revisions, and purchases during that period.

Proved Reserves Pre-Tax PV-10 ($mm)

	Fiscal Year Ending December 31,		
($ in thousands)	2023	2024	2025
Future cash inflows	$ 3,865,302	$ 4,181,440	$ 5,511,802
Future development costs[1]	(545,803)	(652,135)	(764,219)
Future production costs	(1,281,802)	(1,548,957)	(1,824,402)
Future net cash flow	$ 2,037,697	$ 1,980,348	$ 2,923,181
Discounted future income tax expense	-	-	(531,583)
10% discount to reflect timing of cash flows	(1,099,313)	(1,007,830)	(1,310,404)
Standardized measure of disc. net cash flows	$ 938,384	$ 972,518	$ 1,081,193
Pre-Tax PV - 10	**$ 938,384**	**$ 972,518**	**$ 1,332,993**

All-in F&D ($ / mcfe)

	Fiscal Year Ending December 31,		
($ in thousands)	2023	2024	2025
Acquisition Costs:			
Proved properties	$ 274,732	$ 19,172	$ 44,585
Unproved properties	1,047	89,174	5,236
Development Costs	144,121	165,795	274,723
Exploration Costs	-	-	-
Total Acquisition and Development Costs	$ 419,900	$ 274,143	$ 324,544
Reserve Additions:			
Extensions	267,450	216,108	402,953
Revisions to previous estimates	(144,414)	9,354	2,198
Purchases of reserves in place	289,164	-	-
Total Reserve Additions	412,200	225,462	405,150
All-In F&D ($ / mcfe)	**$1.02**	**$1.22**	**$0.80**

Non-GAAP Reconciliations and Definitions

Capital Efficiency

Capital Efficiency Ratio means Adjusted EBITDAX per unit of production divided by finding and development costs ("F&D") per mcfe. F&D is calculated by dividing total costs incurred (which includes the total acquisition, exploration and development costs incurred during the period related to the specified property or group of properties) by the sum of the extensions, discoveries, additions, revisions, and purchases during that period.

DROI

DROI refers to Discounted Return on Investment, which is defined as the present value at a 10% discount rate of future net cashflows excluding capital expenditures divided by the net capital expenditures associated with the development of a horizontal well.

Capital Efficiency (x)

	Fiscal Year Ending December 31,		
($ in thousands)	**2023**	**2024**	**2025**
Adjusted EBITDAX	$ 126,494	$ 195,719	$ 260,978
Total Net Production (MMcfe)	41,406	52,908	77,292
Adjusted EBITDA Margin ($ / mcfe)	$ 3.05	$ 3.70	$ 3.38
All-In F&D ($ / mcfe)	$ 1.02	$ 1.22	$ 0.80
Capital Efficiency	3.00x	3.04x	4.22x