INFINITY

Fourth Quarter 2025 Earnings Call Presentation

March 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 make share repurchases, expected drilling and completions plans and projected well costs 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,” “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 belief, based on currently available information, as to the outcome and timing of future events at the time such statement was made. Such statements are subject to a number of assumptions, risks and uncertainties, including those incident to the development, production, gathering and sale of natural gas, oil 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 the preferred equity investment and the 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; 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 conflicts, 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, 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; 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 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.

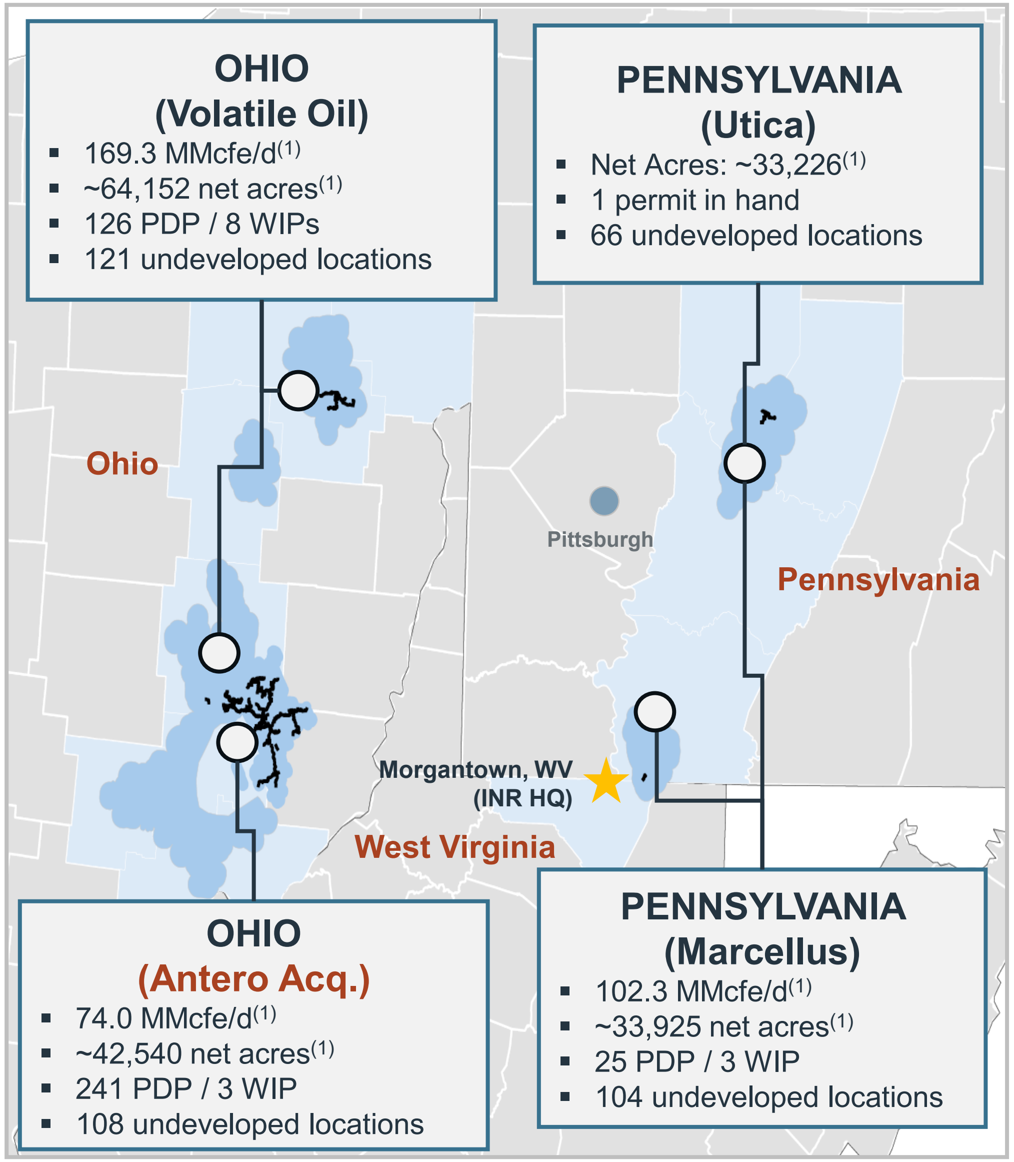
As a result, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements. Therefore, these forward-looking statements are not a guarantee of the Company’s performance, and you should not place undue reliance on such statements. Any forward-looking 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 that disclosure is 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, 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.

High Growth, High Return Pure Play Appalachian Operator

Pure Play Appalachian Operator	▪ **~174,000 net horizon acres** balanced across Ohio and Pennsylvania(1) ▪ Greatest exposure to emerging **volatile oil window** in Ohio **and deep dry gas Utica window** in PA
Fastest Growing Appalachian Operator across Oil and Gas	▪ Fastest growing public Appalachian producer ▪ **46%** overall production growth in 2025(2) ▪ **61%** natural gas growth in 2025(2)
Balanced, Top Tier Inventory Quality and Depth	▪ **~10 to 12 years** of drilling inventory balanced across natural gas and oil weighted opportunities (2 rig) ▪ Leading capital efficient Appalachian operator(2,4)
Strong Operating Margins Support Balance Sheet Strength	▪ **\$3.38 / mcfe Adjusted EBITDAX margin** for 2025, best amongst Appalachian peers(2,4) ▪ **~1.0x net leverage** at LQA Q4'25 provides operational and acquisition related flexibility(1,3,4)
Regionally Located Team with Vast Experience	▪ Deep Appalachian roots backed by seasoned board ▪ **420 acquisitions completed in 2025** ▪ Multi decade operating experience across Appalachia



Note well totals reflect operated wells only.
1. Pro forma for the acquisition of Antero Resources' Ohio assets and Chase Oil assets. Antero acquisitions shown net to INR acquired interest of 60%. Production totals as of Q4 2025.
2. Excludes the impact of Antero and Chase acquisitions.
3. Adjusted for the cash on hand and the restricted cash associated with the Antero acquisition at YE25.
4. Capital efficiency, Adjusted EBITDAX margin and net leverage are non-GAAP measures. See appendix for additional details.

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)]
- Oil-weighted Ohio Utica (32% inventory by lateral ft)
- Liquids-rich Utica development (30%)
- Gas-weighted Marcellus (24%)
- Deep Dry Gas Utica inventory (14%)

Operational Flexibility

- Capital flexibility to shift development across oil, liquids-rich, and dry gas in response to commodity price volatility
- Deep inventory enables cycle-driven capital allocation
- Enhances returns through commodity cycles

Integrated Platform

- Upstream & Midstream integration in PA and OH acquired assets
- Control over gathering, processing, and marketing
- Structurally competitive cost advantages

Basin-Leading Profitability

- Industry-leading Appalachian EBITDA margins per Mcfe
- Low F&D costs drive best-in-class capital efficiency
- Lower break-evens through scale and integrated midstream
- High-margin resource base across the Utica and Marcellus

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

Continuing to Execute on Plan:
Fourth Quarter and Full Year 2025 Results

	4Q 2025	FY 2025
Total Production Volumes	272 *MMcfe/d*	212 *MMcfe/d*
Net Revenues	$117.1 *million*	$356.4 *million*
Operating Costs[1]	$23.2 *million*	$87.4 *million*
Adjusted EBITDAX[2]	$94.0 *million*	$261.0 *million*
Incurred Capital Expenditures	$52.9 *million*	$290.8 *million*
Year End Net Leverage[2] (Net Debt / Adjusted EBITDAX)	~0.3x	

1. Including acquired properties in Ohio.
2. Adjusted EBITDAX and net leverage are non-GAAP measures. See appendix for additional details.

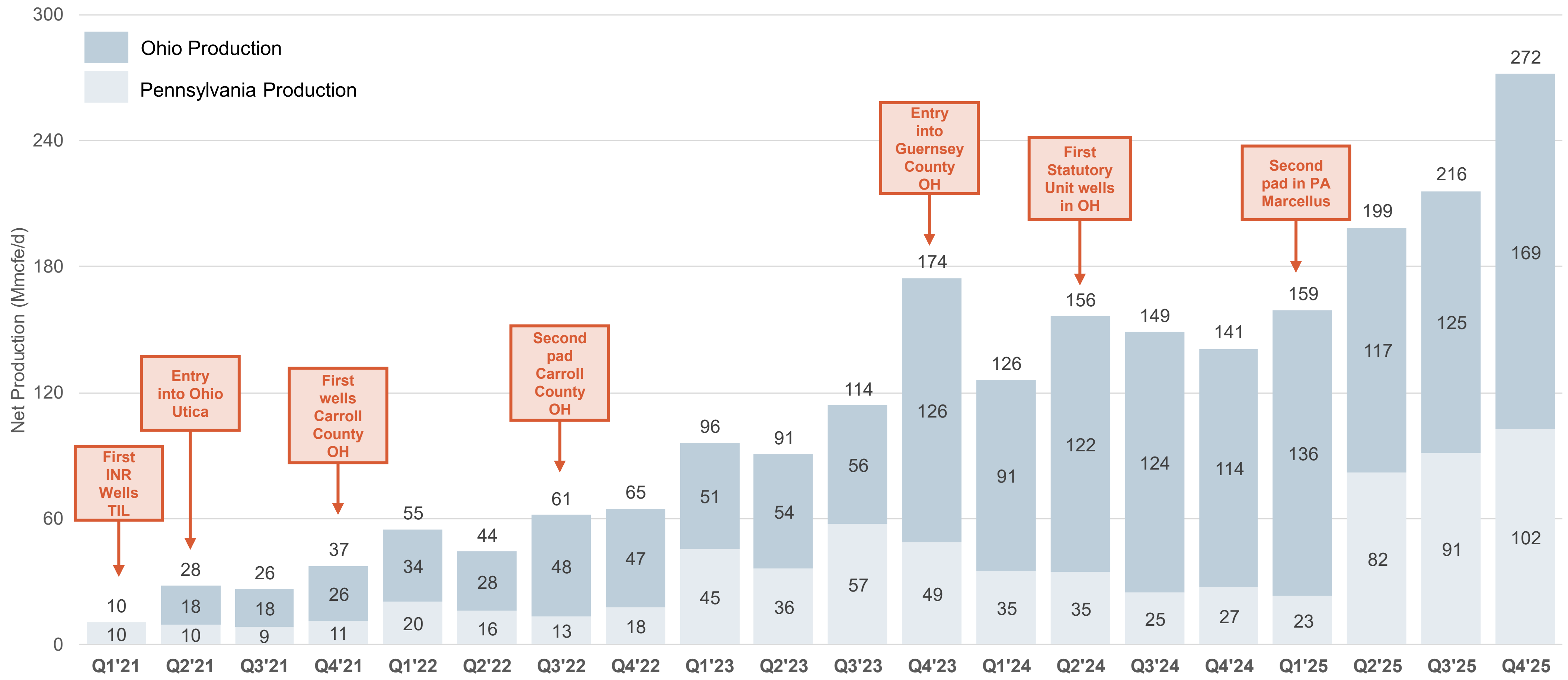
Key Highlights

- **2025 represented the most active operational year in Company history**
  - ***Spudded 25 wells totaling ~405,000 lateral feet***[1]
    - 15 volatile oil wells in Ohio, 7 dry gas Marcellus wells and 3 rich gas Utica wells
  - ***Completed 21 wells totaling ~330,000 lateral feet***
    - 9 volatile oil wells in Ohio and 12 Marcellus wells in Pennsylvania
  - ***TIL 23 wells totaling 363,000 lateral feet***
    - 11 volatile oil wells in Ohio and 12 Marcellus wells in Pennsylvania
- During the Q4'25, INR continued its robust activity levels
  - Spudded 6 volatile oil wells in Ohio and Antero spudded 3 rich gas wells on the acquired assets
  - TIL 3 volatile oil wells and 3 Marcellus wells in PA
- Constructed ~4 miles of permanent gas and water infrastructure to support future development
- Added ~6,700 acres during calendar year 2025, excluding Antero and Chase acquisitions
- Maintained low leverage and strong financial liquidity

Track Record of Execution and Growth…

Since its first acquisition in 2018, Infinity has added ~146,000 net horizon acres through a combination of strategic bolt on acquisitions and privately sourced transactions

Average Net Daily Production Since 2021 (MMcfe/d)

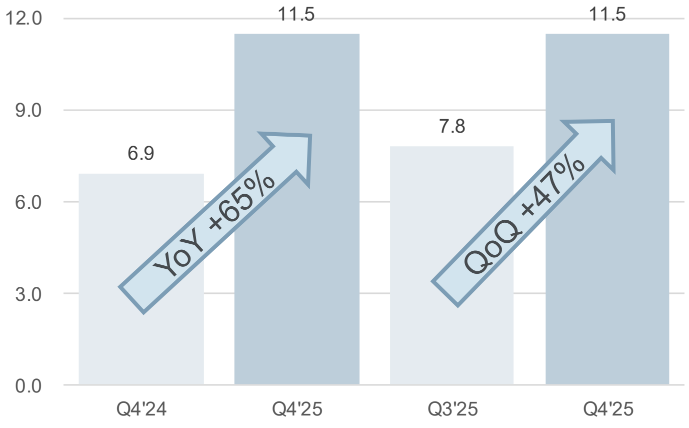


	Q1'21	Q2'21	Q3'21	Q4'21	Q1'22	Q2'22	Q3'22	Q4'22	Q1'23	Q2'23	Q3'23	Q4'23	Q1'24	Q2'24	Q3'24	Q4'24	Q1'25	Q2'25	Q3'25	Q4'25
% Gas	100%	71%	71%	65%	66%	69%	57%	61%	72%	69%	75%	61%	59%	52%	51%	51%	45%	63%	64%	60%
% Oil	0%	8%	8%	15%	17%	13%	23%	19%	13%	15%	11%	23%	21%	29%	29%	29%	31%	19%	22%	25%

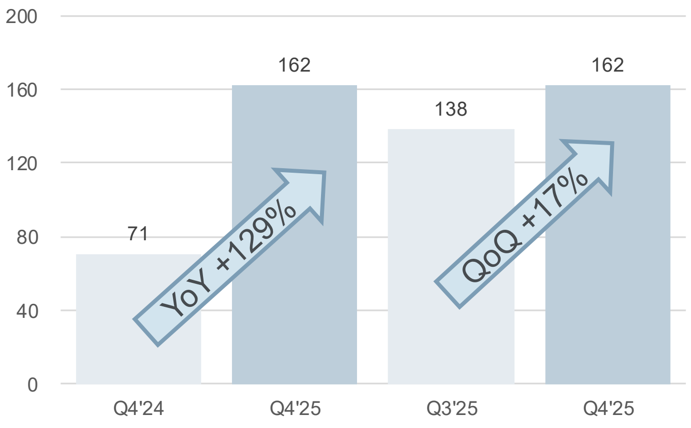
1. Pro forma for the acquisition of Antero's Ohio assets. WIP include three Antero related wells. INR acquired 60% of Antero Ohio's assets.
2. Total wells drilled includes 3 PA Marcellus wells, 6 Legacy INR Ohio wells, and 3 Ohio wells on acquired Antero Ohio assets that are being actively developed.

...While Increasing Cash Flow and Lowering Costs

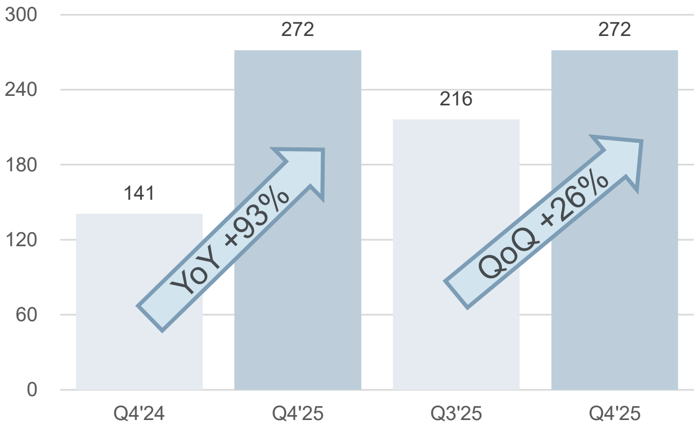
YTD Oil Production (MBbls/d)



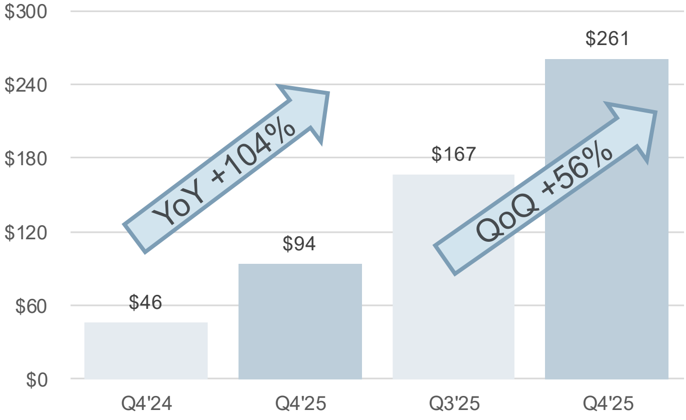
YTD Nat. Gas Production (MMcfe/d)



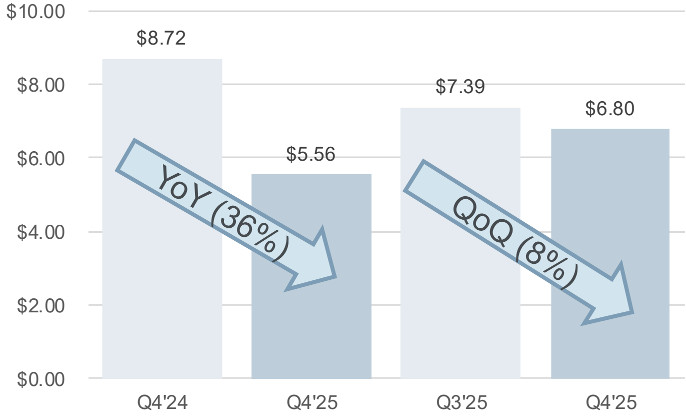
YTD Total Production (MMcfe/d)



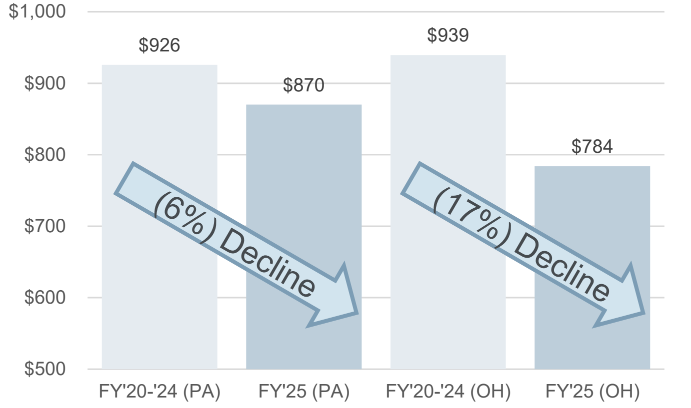
Adjusted EBITDAX[1] ($mm)



Operating Expenses ($ / boe)



Well Costs ($ per lateral feet)[2]



1. Adjusted EBITDAX is a non-GAAP measure. See appendix for additional details.
2. Wells costs represent pre-drill (roads/pad construction), drilling, completion, facilities, and flowback capital

Balanced Inventory Across Commodities Allows Strategic Flexibility in Ever Changing Environment

INR optimizes the value of its resources within two distinct acreage positions that are uniquely oil and gas focused

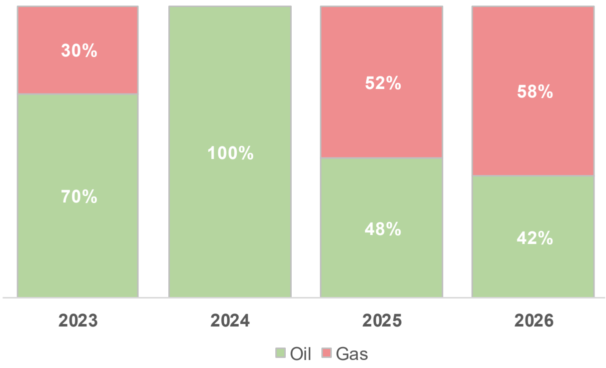
Oil-Weighted Ohio Utica

- Core acreage focused on developing Guernsey, Noble and Carroll counties in Ohio
- ***121*** undeveloped locations (***~6 to 7 years of inventory***)(5)

Oil-Weighted Inventory at $3.50 HHUB(2,4)

WTI ($/Bbl)	$50	$60	$70	$80	$90	$100
DROI (x)	1.5x	1.8x	2.1x	2.5x	2.8x	3.1x

Wells TIL'd by Commodity (%)



Commodity Pricing – WTI *($ / bbl)* & HHUB *($ / mcf)*

	2023	2024	2025	2026
WTI	$77.62	$75.72	$64.81	$73.35
HHUB	$2.74	$2.27	$3.43	$4.04

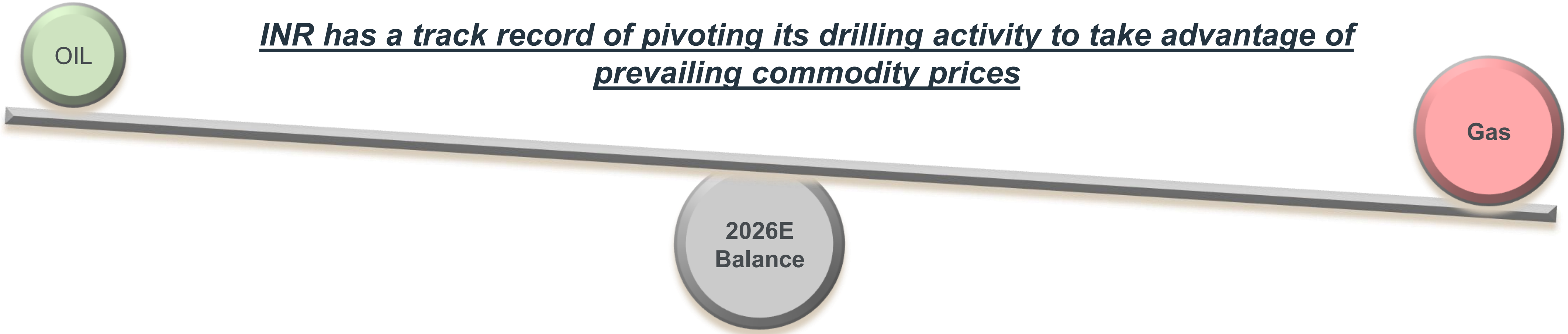
Rich Gas Utica (OH) and Gas-Weighted Marcellus and Deep Dry Gas Utica

- Core acreage focused on developing Armstrong and Indiana counties in Pennsylvania and acquired assets in Noble, Monroe and Belmont counties in Ohio
- ***278*** undeveloped locations (***~14 years of inventory***)(5)

Marcellus (PA) Gas-Weighted Inventory at $70 WTI(3,4)

HH ($/Mcf)	$2.50	$3.00	$3.50	$4.00	$4.50	$5.00
DROI (x)	1.4x	1.9x	2.4x	3.0x	3.5x	4.0x

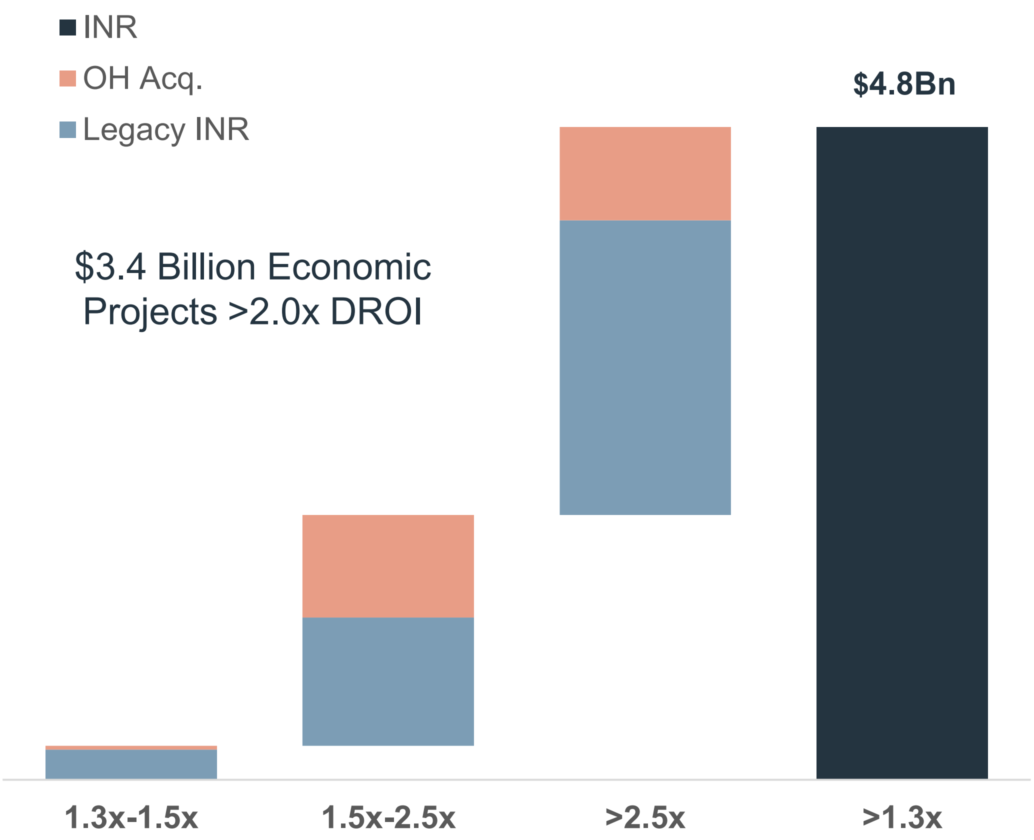
INR has a track record of pivoting its drilling activity to take advantage of prevailing commodity prices



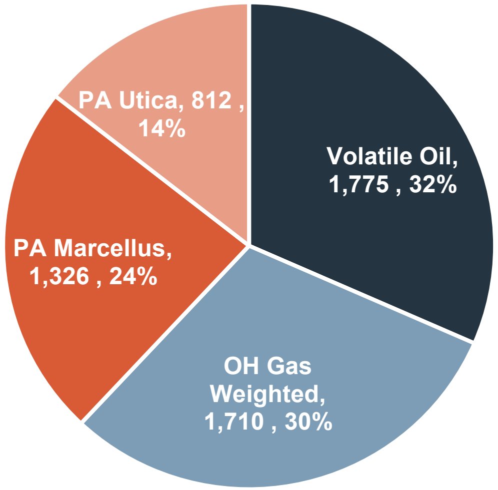
Note: Normalized to 15,000 ft. Totals as of 9/30/2025. Strip as of March 6, 2026.
1. Represents development lateral footage.
2. DROI metrics based on Wolf Run type curve.
3. DROI metrics based on PA North Marcellus type curve. PA Utica DROIs exceed PA Marcellus statistics.
4. Based on type curves of our independent reserve engineer. Well costs are internal projections. Revenue is based on flat $70 oil and $3.50 gas prices. DROI is a non-GAAP measure. See appendix for additional details.
5. Assumes one rig on each commodity.

With Ample High Return Inventory Across Operating Areas

Economic Capital Projects by DROI[(1)]



Total Inventory Lateral Footage by Area (Mft. / %)



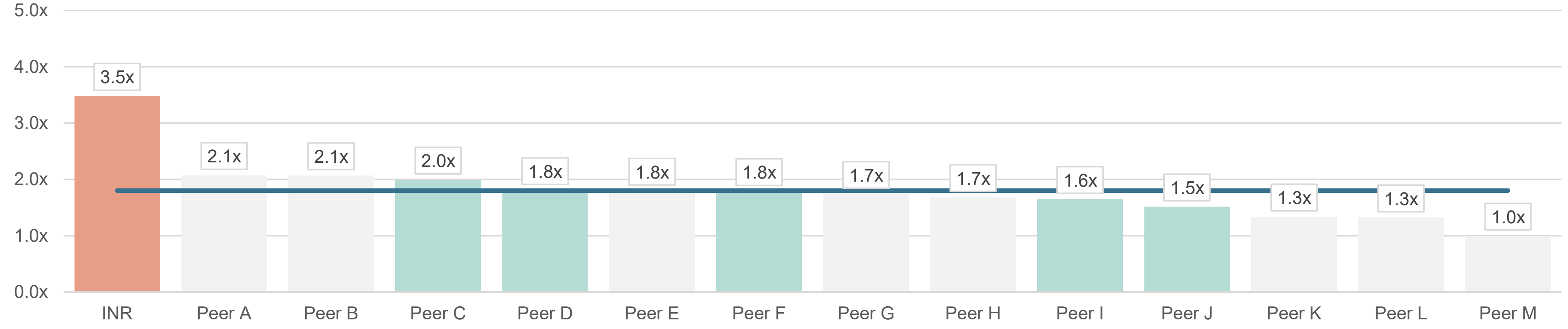
Acquisition adds substantial lateral footage in Ohio's dry gas, rich gas, and oil windows extending INR's highly economic inventory base

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

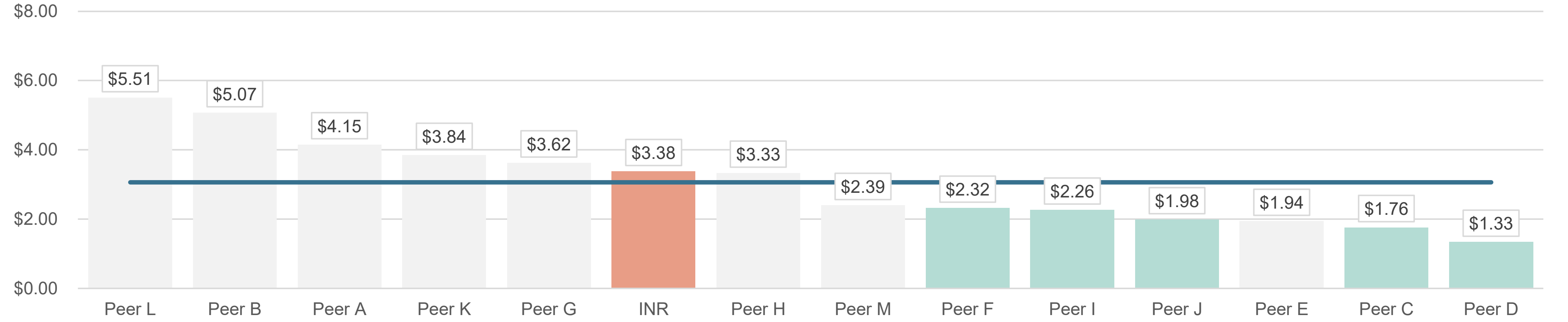
1. DROI is a non-GAAP measure. See appendix for additional details.

Resulting in Leading Capital Efficiency

3 Year Average Capital Efficiency Ratio (x)(1)(2)



2025 EBITDAX Margin ($ / mcfe)(1)(2)



Leading Adj. EBITDAX margin amongst Appalachian peers driven by product mix and low-cost operating structure

Source: Company fillings. SEC filings and company websites.
1. Capital Efficiency Ratio and Adjusted EBITDAX Margin are non-GAAP measures. See appendix for additional details
2. Peer list includes AR, CHRD, CNX, CRGY, CRK, EQT, EXE, GPOR, MGY, MTDR, NOG, PR, and RRC. Green represents Appalachian Basin peers.

Developing Assets Across Our Portfolio

	Volatile Oil Utica (OH)			Rich Gas Utica (OH)			Dry Gas Marcellus (PA)			Deep Dry Gas Utica (PA)			Total Company		
	4Q25	1Q26	2026E	4Q25	1Q26	2026E	4Q25	1Q26	2026E	4Q25	1Q26	2026E	4Q25	1Q26	2026E
Wells Spud															
Gross Wells	6.0	5.0	15.0	3.0	-	16.0	-	6.0	11.0	-	-	1.0	9.0	11.0	43.0
Net Wells	5.8	3.6	12.0	1.7	-	7.7	-	6.0	10.4	-	-	1.0	7.4	9.6	31.1
Total Lateral Footage (1k ft)	83,000	82,000	282,000	59,000	-	171,000	-	92,000	163,000	-	-	10,000	142,000	174,000	626,000
Avg. Lateral (1k ft.)	14,000	16,000	19,000	20,000	-	11,000	-	15,000	15,000	-	-	10,000	16,000	16,000	15,000
Wells Completed															
Gross Wells	-	8.0	13.0	-	-	15.0	-	3.0	8.0	-	-	-	-	11.0	36.0
Net Wells	-	7.8	11.3	-	-	7.7	-	3.0	7.5	-	-	-	-	10.8	26.5
Total Lateral Footage (#)	-	110,000	191,000	-	-	184,000	-	47,000	120,000	-	-	-	-	157,000	495,000
Avg. Lateral (1k ft.)	-	22,000	13,000	-	-	12,000	-	8,000	11,000	-	-	-	-	14,000	14,000
Wells Turned-in-Line ("TIL")															
Gross Wells	3.0	4.0	13.0	-	-	10.0	3.0	-	8.0	-	-	-	6.0	4.0	31.0
Net Wells	2.7	4.0	11.3	-	-	5.2	2.9	-	7.5	-	-	-	5.6	4.0	24.1
Total Lateral (1k ft)	58,000	54,000	191,000	-	-	115,000	45,000	-	120,000	-	-	-	103,000	54,000	426,000
Avg. Lateral (1k ft.)	19,000	13,000	15,000	-	-	11,000	15,000	-	15,000	-	-	-	17,000	14,000	14,000

2026 program slightly weighted towards natural gas development while continuing to develop oil weighted projects

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

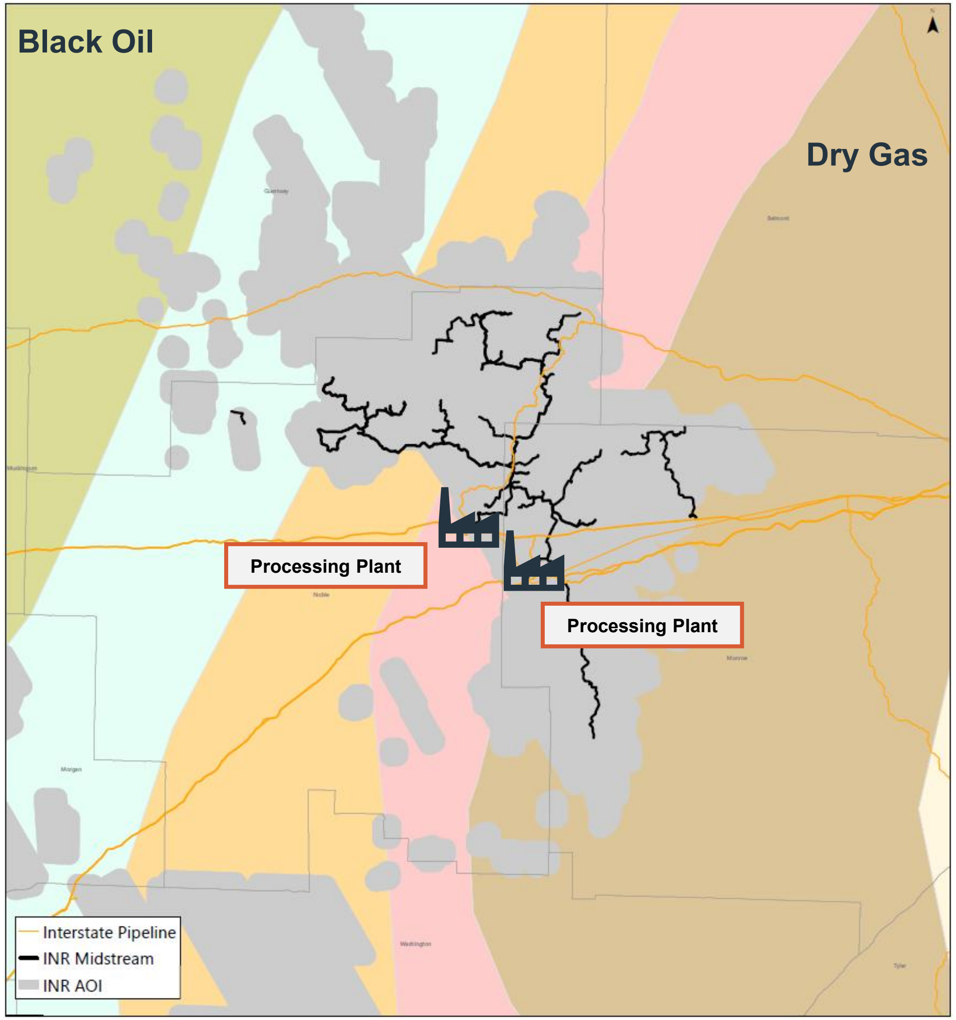
Acquired Midstream Assets Support Development in Ohio Utica while Providing Additional Revenue Opportunities

Addition of strategic midstream system supports development of acquired properties

Key Highlights

- Acquired strategic assets from Antero Midstream
- $400 million allocated value (estimated replacement cost ~$500 million)
- 60% INR ownership with NOG owning 40%
- ~141 miles of low-pressure and high-pressure gathering lines and 6 compressor facilities, supporting ***600 MMcf/d of throughput capacity***
- ~90 miles of water lines with 12 water storage facilities
- System supports the gathering and development infrastructure to exploit vast resource potential
- Strategically located in high development region with ability to support development across multiple phase windows
- Reduces operational costs, lowering development costs and cash break-evens
- Adds complementary revenue generation in close proximity to regional gas development

Ohio Infrastructure Map



2026 Outlook and Guidance

Net Production			
Total Net Production (Mmcfe/d)	345	–	375
Total Natural Gas Net Production (Mmcf/d)	235	–	255
Total Liquids & Oil Net Production (Mbbls/d)	18	–	20
Incurred Development Capital Expenditures[1]	$450	–	$500

Operated Rigs	~ 2 Rigs
Legacy INR Asset Base	~ 1 Rigs
Recently Acquired Assets	~ 1 Rigs

Operated Drilling Program	
TILs (Gross)	~30 Wells
Legacy INR Asset TILs (Gross)	~20 Wells
Recently Acquired Assets TILs (Gross)	~10 Wells

Additional Commentary

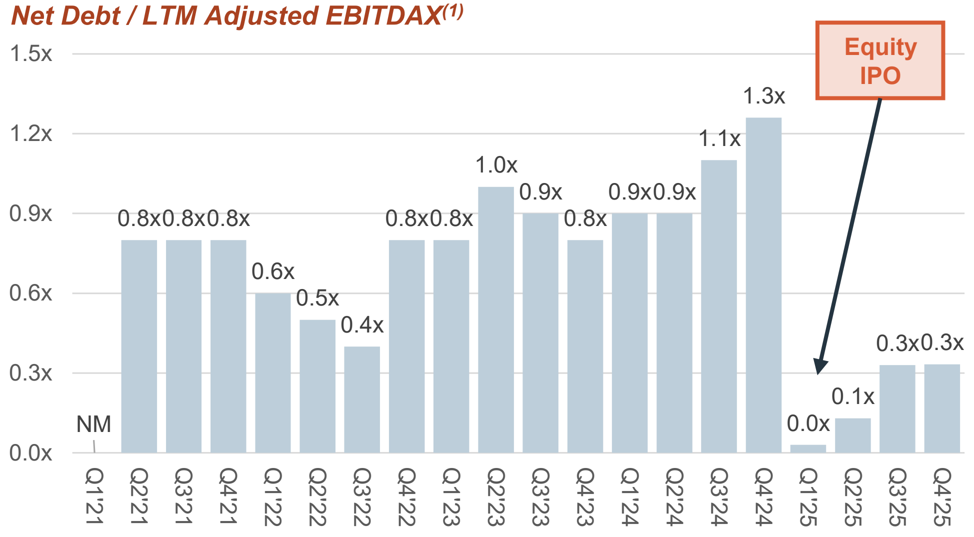
- Anticipated to deliver **~70% production** growth year over year at the midpoint of the range
- 72% of drilling activity allocated to Ohio related projects and 28% to Pennsylvania projects
- Continued focus on development of long laterals across all areas of development with average spudded lateral length in 2026 ~15,000’
- Anticipate total wells drilled lateral footage >600,000 lateral feet while turning into sales >425,000 lateral feet
- Anticipate operating two rigs across asset base with ~1 rig targeting development of recently acquired Ohio assets

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

Strong Balance Sheet Supports Strategic and Financial Flexibility

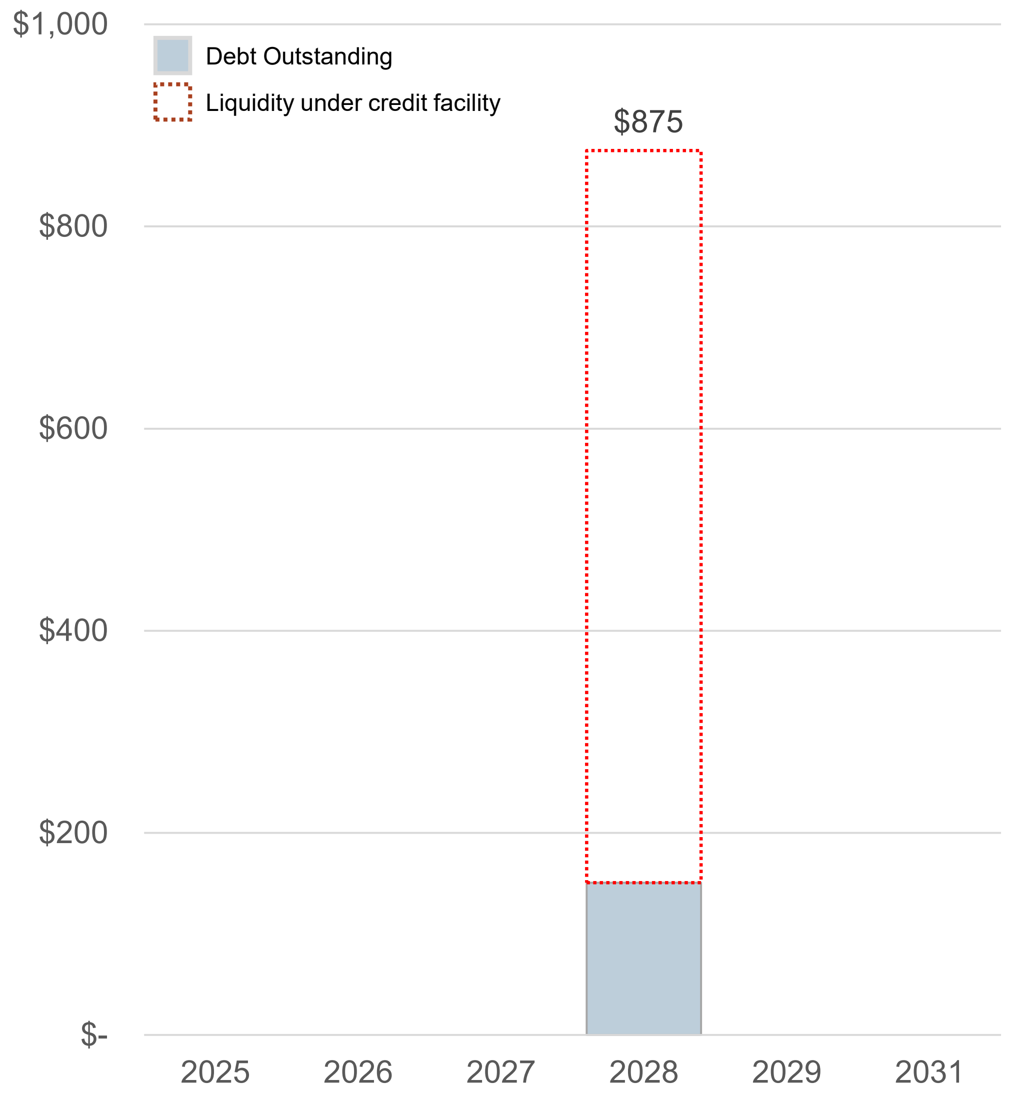
- **Target net leverage of less than 1.0x**
  - Maintain active hedge program
    - Natural gas hedges extend outward five years
    - Oil / liquids hedges extend into 2027
- Issuance of convertible perpetual preferred further strengthens balance sheet

INR Historically Targets Low Leverage



1. Nebt debt, Adjusted EBITDAX and net leverage are non-GAAP measures. See appendix for additional details.

Significant Liquidity with no Near-Term Maturities



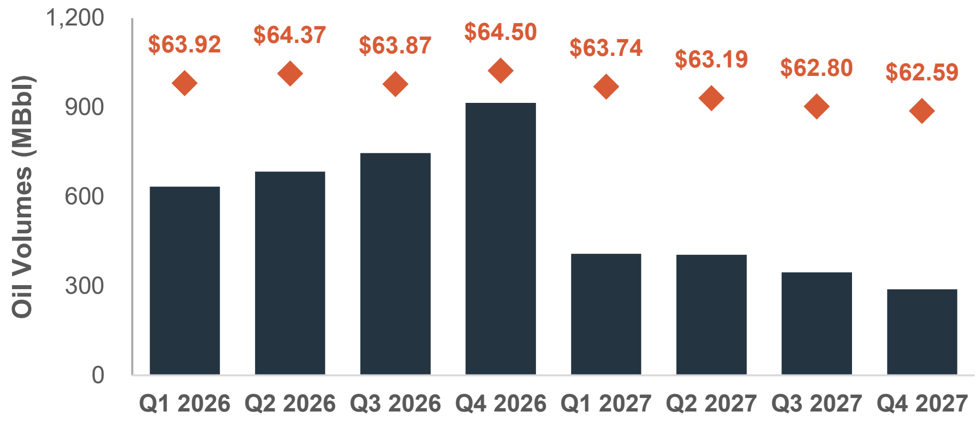
Active Hedge Program to Lock in DROI and Maintain Balance Sheet Strength

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

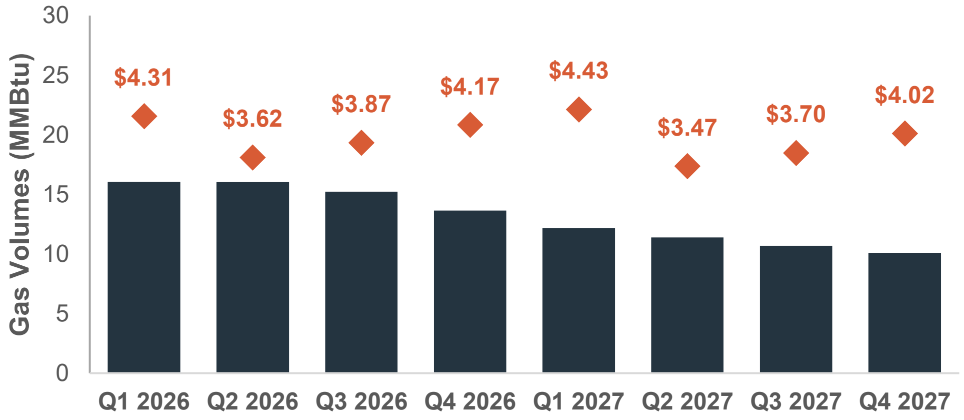
Hedging Philosophy

- INR actively hedges its commodity exposure with its bank group
  - 197 Bcf of HHub hedges thru 2030 at an avg. price of $3.81/mcf
  - 4.4 MMbbls of oil hedges thru 2027 at an avg. price of $63.84/bbl
  - 1.0 MMbbls of NGL hedges thru 2027 at an avg. price of $28.86/bbl
- INR hedges primarily consist of swaps and collars

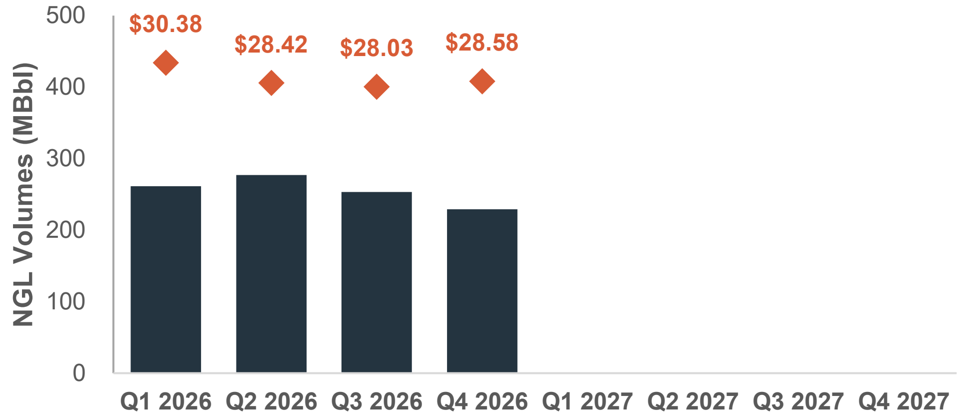
Oil Hedges



Natural Gas Hedges(1)



Natural Gas Liquids Hedges



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

Appendix

Reserve Summary as of December 31, 2025

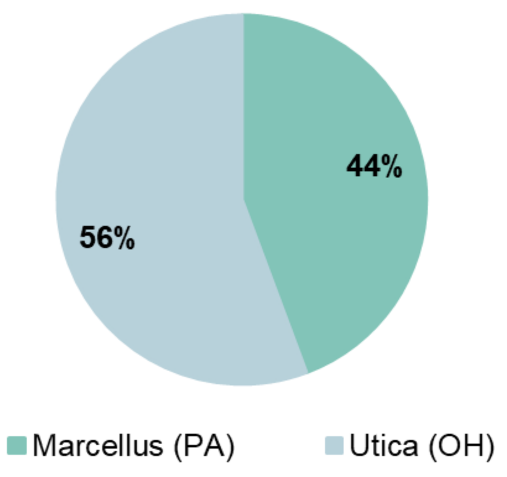
Key Points

- INR has increased its proved reserves 32% from 1,022 Bcfe to 1,350 Bcfe
- INR 2025 all in F&D costs excluding recent transactions totaled $0.80 / mcfe
- 3 year all in F&D cost of $0.98 / mcfe remains best in class amongst Appalachian peers
- INR 3-year capital efficiency ratio of 3.48x remains best in class amongst Appalachian peers

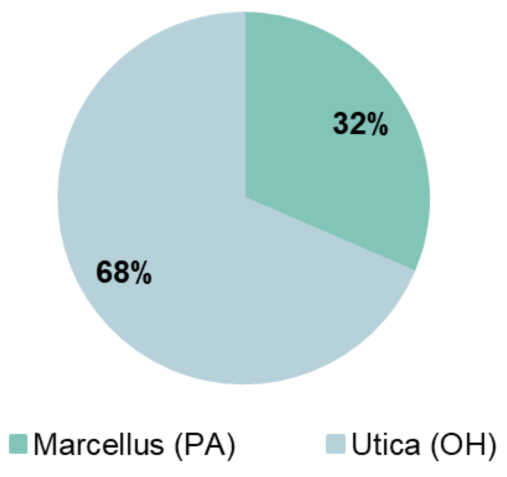
Proved Net Reserve Summary

Category	Natural Gas (Mmcf)	NGL's (MBbls)	Oil (MBbls)	Equivalent (Mmcfe)	Undisc. Cash Flow ($000s)	Cap Ex ($000s)	SEC PV-10 ($000s)
1PDP	416,067	15,813	14,573	598,385	$ 1,505	$ 24	$ 793
2PDNP	1,294	145	143	3,026	$ 5	$ 1	$ 3
3PUD	499,262	19,589	21,954	748,520	$ 1,416	$ 739	$ 539
Total Proved	**916,624**	**35,547**	**36,671**	**1,349,931**	**$ 2,926**	**$ 764**	**$ 1,335**

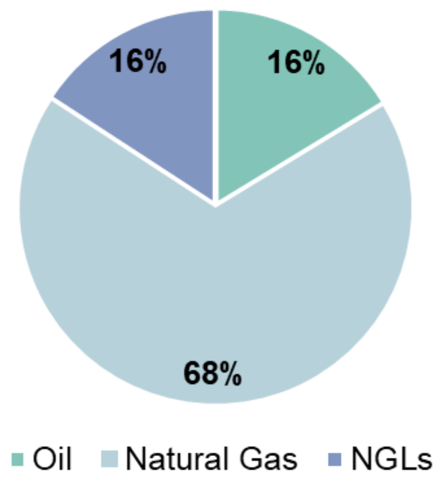
Proved Reserves by Field



SEC PV-10 by Field



Proved Reserves by Commodity (6:1)



1. F&D costs and capital efficiency are non-GAAP measures. See appendix for additional details.

Hedge Book Overview – As of 6-Mar-26

	FY 2026					FY 2027					FY 2028				
	Q1	Q2	Q3	Q4	2026	Q1	Q2	Q3	Q4	2027	Q1	Q2	Q3	Q4	2028
WTI Fixed															
Total Volume (MBbl)	634	685	746	916	2,980	408	405	346	289	1,448	-	-	-	-	-
Daily Volume (Bbl/d)	7,039	7,525	8,111	9,951	8,164	4,533	4,453	3,758	3,139	3,966	-	-	-	-	-
WAVG Floor Price ($ / Bbl)	$63.92	$64.37	$63.87	$64.50	$64.19	$63.74	$63.19	$62.80	$62.59	$63.13	-	-	-	-	-
Henry Hub Fixed															
Total Volume (BBtu)	16,061	16,040	15,230	13,644	60,975	12,167	11,390	10,688	10,089	44,334	9,450	8,990	8,670	8,260	35,370
Daily Volume (MMBtu/d)	178,456	176,264	165,543	148,304	167,055	135,189	125,165	116,174	109,663	121,463	103,846	98,791	94,239	89,783	96,639
WAVG Floor Price ($ / 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	$3.76
Dom South Basis															
Total Volume (BBtu)	12,276	11,347	10,137	9,065	42,825	7,131	3,140	3,320	3,280	16,871	2,940	2,780	2,670	2,540	10,930
Daily Volume (MMBtu/d)	136,400	124,692	110,185	98,533	117,329	79,233	34,505	36,087	35,652	46,222	32,308	30,549	29,022	27,609	29,863
WAVG Floor Price ($ / 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)	($0.90)
Dom South Fixed															
Total Volume (BBtu)	795	2,001	4,544	4,296	11,636	3,220	2,696	2,360	2,096	10,372	-	-	-	-	-
Daily Volume (MMBtu/d)	8,833	21,989	49,391	46,696	31,879	35,778	29,626	25,652	22,783	28,416	-	-	-	-	-
WAVG Floor Price ($ / MMBtu)	$3.70	$2.83	$2.99	$3.12	$3.06	$3.60	$2.62	$2.60	$2.84	$2.96	-	-	-	-	-
Tetco M2 Basis															
Total Volume (BBtu)	473	461	451	436	1,821	366	413	403	385	1,566	1,280	1,228	1,210	1,155	4,873
Daily Volume (MMBtu/d)	5,256	5,066	4,902	4,739	4,989	4,067	4,533	4,375	4,185	4,290	14,066	13,489	13,152	12,554	13,313
WAVG Floor Price ($ / 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)	($0.86)
REX Zone 3 Basis															
Total Volume (BBtu)	-	4,230	4,640	4,140	13,010	2,775	2,775	2,775	2,775	11,100	4,490	4,366	4,270	4,158	17,284
Daily Volume (MMBtu/d)	-	46,484	50,435	45,000	35,644	30,833	30,495	30,163	30,163	30,411	49,341	47,981	46,413	45,190	47,223
WAVG Floor Price ($ / 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-Mar-26

	FY 2029					FY 2030					FY 2031				
	Q1	Q2	Q3	Q4	2029	Q1	Q2	Q3	Q4	2030	Q1	Q2	Q3	Q4	2031
WTI Fixed															
Total Volume (MBbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (Bbl/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / Bbl)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Henry Hub Fixed															
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 Floor Price ($ / MMBtu)	$4.06	$3.14	$3.44	$3.80	$3.61	$4.02	$3.10	$3.37	$3.73	$3.56	-	-	-	-	-
Dom South Basis															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dom South Fixed															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2 Basis															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
REX Zone 3 Basis															
Total Volume (BBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Daily Volume (MMBtu/d)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / MMBtu)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Hedge Book Overview – As of 6-Mar-26

	FY 2026					FY 2027					FY 2028				
	Q1	Q2	Q3	Q4	2026	Q1	Q2	Q3	Q4	2027	Q1	Q2	Q3	Q4	2028
Ethane Fixed															
Total Volume (MGal)	2,441	2,440	2,294	2,137	9,312	-	-	-	-	-	-	-	-	-	-
Daily Volume (Gal/d)	27,122	26,813	24,935	23,228	25,512	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / Gal)	$0.28	$0.27	$0.28	$0.29	$0.28	-	-	-	-	-	-	-	-	-	-
Propane Fixed															
Total Volume (MGal)	5,259	5,726	5,237	4,679	20,901	-	-	-	-	-	-	-	-	-	-
Daily Volume (Gal/d)	58,433	62,923	56,924	50,859	57,263	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / Gal)	$0.76	$0.70	$0.69	$0.71	$0.71	-	-	-	-	-	-	-	-	-	-
Normal Butane Fixed															
Total Volume (MGal)	1,547	1,698	1,558	1,395	6,198	-	-	-	-	-	-	-	-	-	-
Daily Volume (Gal/d)	17,189	18,659	16,935	15,163	16,981	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / Gal)	$0.87	$0.80	$0.80	$0.81	$0.82	-	-	-	-	-	-	-	-	-	-
IsoButane Fixed															
Total Volume (MGal)	951	1,032	945	846	3,774	-	-	-	-	-	-	-	-	-	-
Daily Volume (Gal/d)	10,567	11,341	10,272	9,196	10,340	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / Gal)	$0.89	$0.83	$0.82	$0.83	$0.84	-	-	-	-	-	-	-	-	-	-
Natural Gasoline Fixed															
Total Volume (MGal)	772	734	600	571	2,677	-	-	-	-	-	-	-	-	-	-
Daily Volume (Gal/d)	8,578	8,066	6,522	6,207	7,334	-	-	-	-	-	-	-	-	-	-
WAVG Floor Price ($ / Gal)	$1.40	$1.37	$1.36	$1.35	$1.37	-	-	-	-	-	-	-	-	-	-

Non-GAAP Reconciliations and Definitions

Adjusted EBITDAX

Adjusted EBITDAX is defined as net income (loss) plus interest, net, income tax expense (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 long-term debt. Net Debt is a non-GAAP measure which our management uses to evaluate our financial position, including our ability to service our debt obligations. Net leverage is calculated as Net Debt divided by Adjusted EBITDAX.

Adjusted EBITDAX Reconciliation

	Three Months Ended			Twelve Months Ended December 31,	
($ in thousands)	**12/31/24**	**09/30/25**	**12/31/25**	**12/31/24**	**12/31/25**
Net Income	$ (5,517)	$ 40,014	$ 80,354	$ 49,286	$ 63,959
Interest, net	5,266	2,290	2,950	21,529	9,667
Income tax expense (benefit)	-	(3,383)	(922)	-	(4,858)
Depreciation, depletion and amortization	17,382	27,579	31,261	73,726	103,750
(Gain) loss on derivative instruments	28,444	(15,250)	(28,253)	22,047	(58,406)
Net cash settlements received (paid) on deriv.	605	6,374	6,647	28,360	12,214
Non-recurring transaction expenses	-	172	343	771	1,601
Non-cash compensation expenses[1]	-	2,253	1,647	-	133,053
Adjusted EBITDAX	**$ 46,180**	**$ 60,049**	**$ 94,027**	**$ 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)

	Period Ending			
($ in thousands)	**03/31/25**	**06/30/25**	**09/30/25**	**12/31/25**
Total debt outstanding	$ 11,391	$ 34,378	$ 75,363	$ 150,847
Less: Cash and cash equivalents	$ (4,859)	$ (6,282)	$ (4,572)	$ (64,049)
Net debt outstanding	$ 6,532	$ 28,096	$ 70,791	$ 86,798
Last Quarter Annualized Adjusted EBITDAX[1]	$ 228,984	$ 198,564	$ 240,196	$ 376,108
Net debt to LQA EBITDAX	0.0x	0.1x	0.3x	0.2x

1. Represents adjusted EBITDAX (reconciled in the Appendix) 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 individual 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.

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