INFINITY

3Q 2025
Earnings Presentation

November 2025

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, future capital spending plans, capital efficiency, 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 risks and uncertainties 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 risks include, but are not limited to, 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, continued hostilities in the Middle East 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.

Premier Appalachian Operator with Balanced Inventory

Infinity Natural Resources Overview

Top Tier Inventory with Leading Capital Efficiency

- Technical focus with sector leading operational performance delivering on extended lateral inventory
- Strong and improving EBITDAX margin with basin-leading F&D drives top-tier capital efficiency

Organic Growth Funded Via Internal Cash Flow

- Proven track record growing production through drill-bit enhanced with bolt-on acquisitions
- Production growth of 28% in 2024 and greater than 40%[(2)] expected in 2025

Commitment to a Strong Balance Sheet

- Committed to financial discipline with strong balance sheet, liquidity, and commodity hedge book

Deep Appalachian Roots backed by Seasoned Board

- Local presence and extensive Appalachian network offers a distinguishing competitive advantage
- Supportive board of directors with demonstrated history of growing successful E&P entities

~126,000[(3)]
Net Horizon Acres

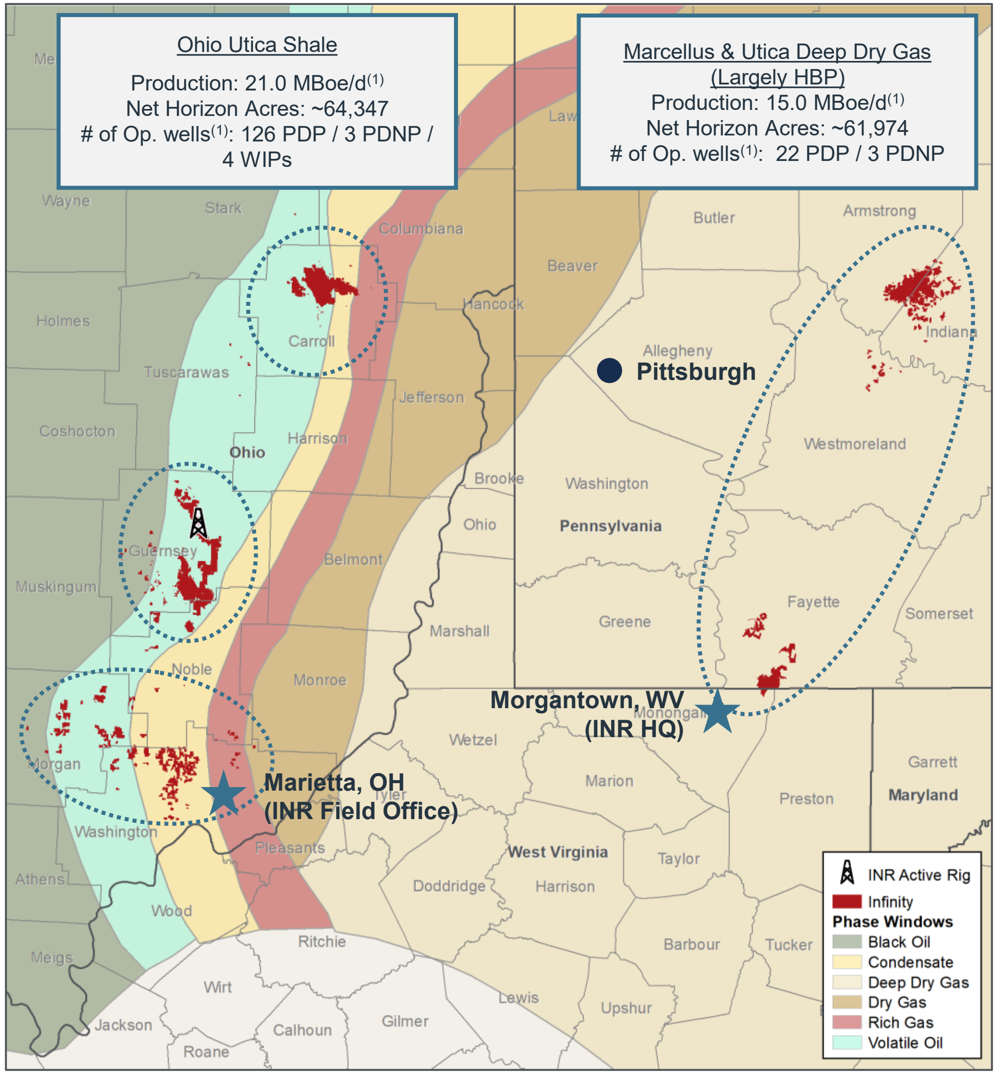
39%
Q3'25 YoY Production Growth

18 Years
High-Quality, Balanced Inventory

~0.3x
3Q'25 Leverage

~$304 Million[(4)]
Total Liquidity

Unique Appalachian Footprint

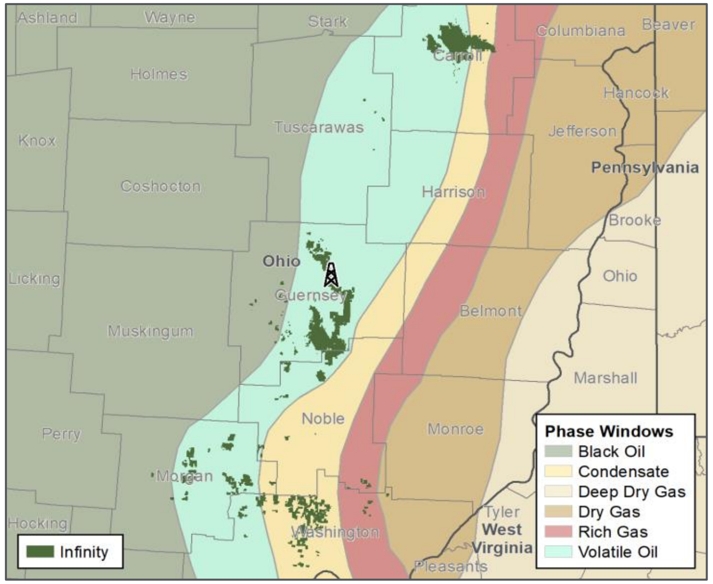


1. As of 3Q 2025
2. Represents the midpoint of the 2025E production guidance range
3. Represents current acreage total
4. Liquidity includes the impact of the October borrowing base increase to $375 million

Balanced Inventory Accommodates All Commodity Environments

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

Oil-Weighted Ohio Utica
145 Locations
3 PDNP & 4 WIPs
1,892 Total Lateral Feet (000s)(1)
Breakeven realized oil price of $27.80 per barrel



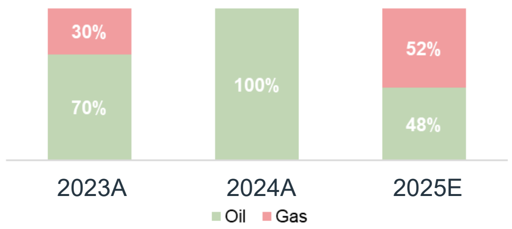
Oil-Weighted Inventory at $3.50 HHUB(2)

WTI ($/Bbl)	$50	$60	$70	$80	$90	$100
DROI (x)(5)	1.5x	1.8x	2.1x	2.5x	2.8x	3.1x

Flexible Capital Program to Optimize Returns

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

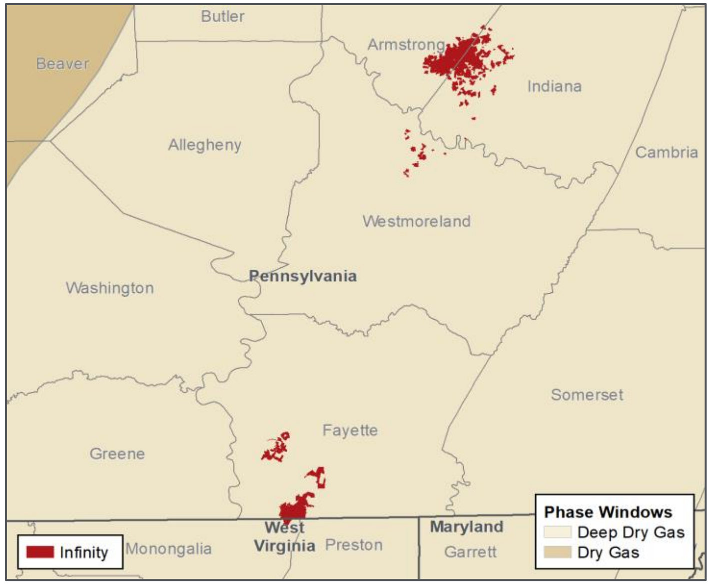
Wells TIL'd by Commodity (%)



Benchmark Commodity Pricing (WTI/HH)

2023A:	2024A:	2025E:
$70.60	$67.78	$65.07(4)
$2.74	$2.27	$3.38(4)

Gas-Weighted Pennsylvania Dry Gas Marcellus and Deep Dry Gas Utica
170 Locations
3 PDNP
2,192 Total Lateral Feet (000s)(1)
Breakeven realized gas price of $1.35 per MMbtu



Gas-Weighted Inventory at $70 WTI(3)

HH ($/Mcf)	$2.50	$3.00	$3.50	$4.00	$4.50	$5.00
DROI (x)(5)	1.4x	1.9x	2.4x	3.0x	3.5x	4.0x

Note: Normalized to 15,000 ft. Totals as of 9/30/2025.
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. Strip pricing as of October 30th, 2025.
5. 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.

3rd Quarter 2025 Highlights

Operating Highlights

- **10 wells turned into sales** during the quarter **(most active in company history)** totaling 162,000 lateral feet
- Continued development activity during quarter:
  - Five wells drilled to TD, one WIP
    - Three Pennsylvania Marcellus gas wells
    - Three Ohio Utica oil wells
  - Drilled ~93,000 lateral feet
    - Drilled three Marcellus laterals totaling 50,000 lateral feet
  - Completed 442 stages
  - Spud two additional oil weighted wells in Ohio
- Delivered 31% overall production growth in the nine months-ended 9/30 2025 vs 2024
  - Natural gas production and oil production up **41%** and **16%**, respectively
  - Mix continues to shift to natural gas on strength of Pennsylvania Marcellus wells
- **Positioned for significant Adjusted EBITDAX and cash flow growth in 4Q'25**

Financial Statistics

	3Q 2025	3Q 2024
Total Production Volumes	36.0 MBoe/d	26.0 MBoe/d
Net Revenues	$79.7 Million	$69.2 Million
Operating Costs[1]	$20.4 Million	$22.5 Million
Adjusted EBITDAX[2]	$60.0 Million	$56.2 Million
Incurred Capital Expenditures[3]	$83.2 Million	$25.0 Million
Leverage (Debt / Adj. EBITDAX)[2]	~0.3x	~1.1x

1. Includes LOE, GP&T, and taxes other than income.
2. Adjusted EBITDAX is a non-GAAP financial measure, see appendix for additional details.
3. Includes incurred D&C capital expenditures along with midstream capital expenditures for the respective period.

Go-Forward Operational Activity

- Turned into sales three oil wells in October
  - 56,000 lateral feet of Ohio oil production
  - New longest lateral of 22,500 feet turned to production
- Concluded stimulation/completion activities on most recent natural gas pad
  - Demonstrated superior efficiency and cost controls during severe drought conditions
  - Expected turn-in-line on pace for 4Q'25
- Constructing additional gas pad with plans to begin development in 1H'26
- Concluded drilling operations on two oil well pads with anticipated production in 1H'26
  - 2-well, ~27,000 lateral feet pad in Guernsey County
  - 2-well, ~27,000 lateral feet pad in Carroll County
- Additional oil-weighted drilling program in process
  - 4-well, 56,000 lateral feet pad in Guernsey County

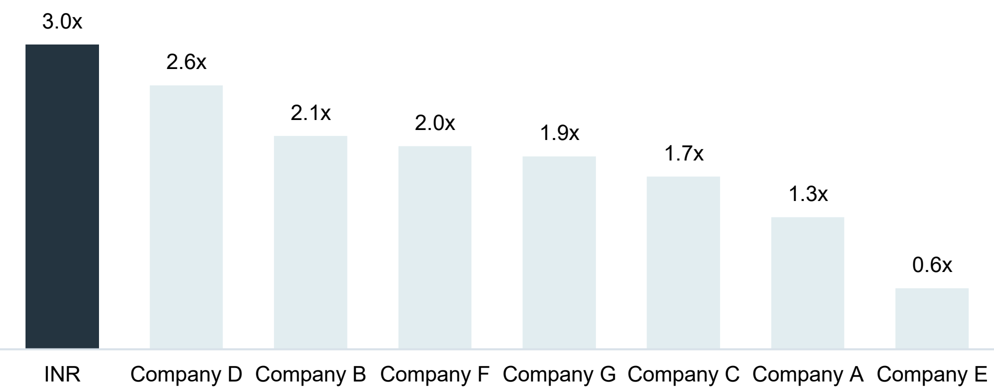
Ohio Drilling Operations

Pennsylvania Stimulation Operations

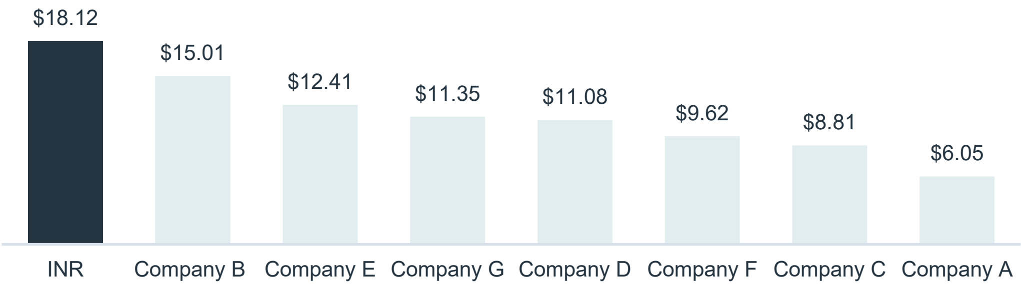
High Returns and Low Finding Cost Yields Leading Capital Efficiency

- **Leading capital efficiency among Appalachian peers**
  - INR three-year average capital efficiency of 3.5x
- **Leading Adjusted EBITDAX margin[2] driven by oil-weighted product mix and low-cost operating structure**
  - Finding costs anticipated to decrease driven by increased natural gas development in 2025

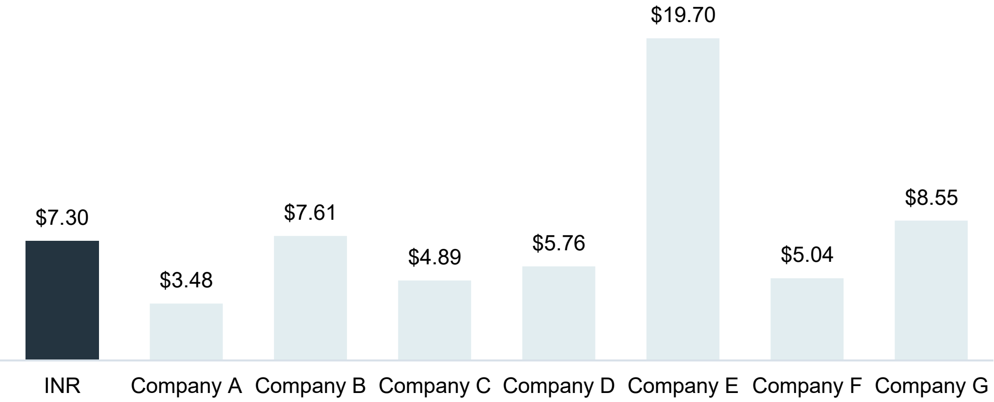
2024A Capital Efficiency Ratio[1][2]
(x)



3Q 2025 Adjusted EBITDAX Margin[1][2]
($ / Boe)



2024A All-In F&D[1][2]
($ / Boe)



Note: Source: Peer company fillings. FactSet.
1. Companies include AR, CNX, CTRA, EQT, EXE, GPOR, RRC.
2. Capital Efficiency Ratio, All-In F&D, and Adjusted EBITDAX Margin are non-GAAP measures. See appendix for additional details. Company C uses cash margin as proxy for Adjusted EBITDAX, and companies F and G are shown as Adjusted EBITDA margin.

Low Leverage Provides Operational and Financial Flexibility

Financial Profile and Commentary

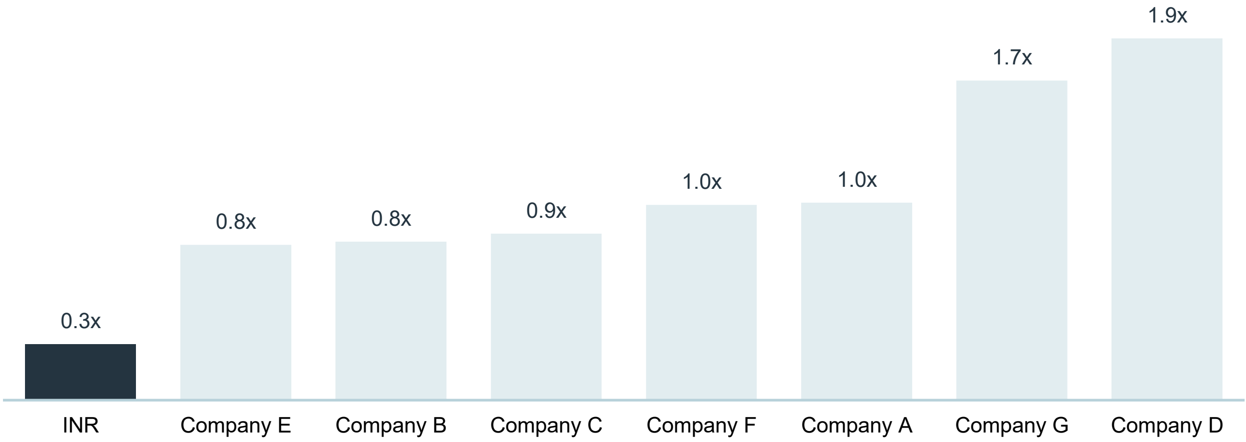
- **Target net leverage of less than 1.0x**
  - 3rd quarter 2025 leverage of 0.3x[1] provides financial flexibility and derisks development plan
- **3rd quarter 2025 liquidity of ~$304 million**[3]
  - ~$5 million of cash on hand
- Low leverage and financial flexibility allows INR to develop assets prudently and maximize returns
- Maintaining a strong balance sheet provides the ability to strategically capitalize on bolt-on acquisition opportunities
- INR maintains an active and disciplined hedge program

$75 million share repurchase program authorized in 4Q'25

Leverage Benchmarking vs Select Natural Gas Peers

3rd Quarter 2025 Net Debt[1] / 3Q'25A Adjusted EBITDAX[1][2]
(x)

Largely unfunded $375 million RBL with ample duration (2028 maturity)



Source: Peer company fillings. FactSet.
1. Net Debt and Adjusted EBITDAX are non-GAAP measures. See appendix for additional details.
2. Companies include AR, EXE, CNX, CTRA, EQT, GPOR, RRC
3. Liquidity includes the impact of the October borrowing base increase to $375 million

2025 Outlook and Guidance

Development Capital Expenditures[1]

$270 million - $292 million

Total Net Daily Production:

33.5 – 35 MBoe/d

Development Plan:

Anticipate Running 1.2 operated rigs throughout the year

1. Includes D&C and Midstream Capital Expenditures

Environmental Social Governance

Infinity's ESG Focus

- ***Diligent Tracking and Reporting*** ✓
- ***Modern Facility Design*** ✓
- ***Water Recycling and Sharing*** ✓
- ***Charitable Contributions*** ✓
- ***Community Support*** ✓

Achievements

- Owns and operates modern, unconventional assets; minimal near-term P&A liability
- Operates in highly regulated operating environment with stringent environmental standards in Ohio and Pennsylvania with zero flaring
- Minimal produced water generated from operations reduces exposure to takeaway capacity constraints and saltwater disposal liability
- Zero Infinity employee recordable incidents in Company's history
- Invests significant capital to ensure compliance of acquired assets and optimization of new assets
- Partners with nearby operators to share produced water and minimize disposal
- Engages with industry experts to measure and track our emissions to ensure accurate reporting
- Headquartered among our assets, INR is corporately and personally invested in the communities in which we operate

Investment Highlights

- Core Acreage with Deep, High-Return Drilling Inventory Across Commodities
- Disciplined, Low-Cost Operator Generating Top Tier Well Results
- Strategic Long-Term Growth Driven by Deep Appalachian Roots
- Strong Balance Sheet with Minimal Debt
- Proven Management Team Backed by Leading Energy Sponsor

Appendix

Initial Public Offering Highlights

INR
LISTED
NYSE

January 30th, 2025
Priced Initial Public Offering (IPO)

$286 million(1)
in Proceeds

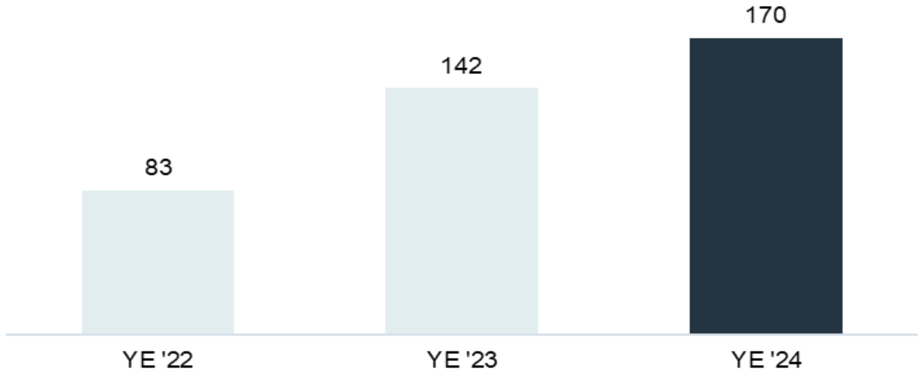
15.2 million(2)
Shares Issued via IPO

60.9 million(3)
Total Shares Outstanding

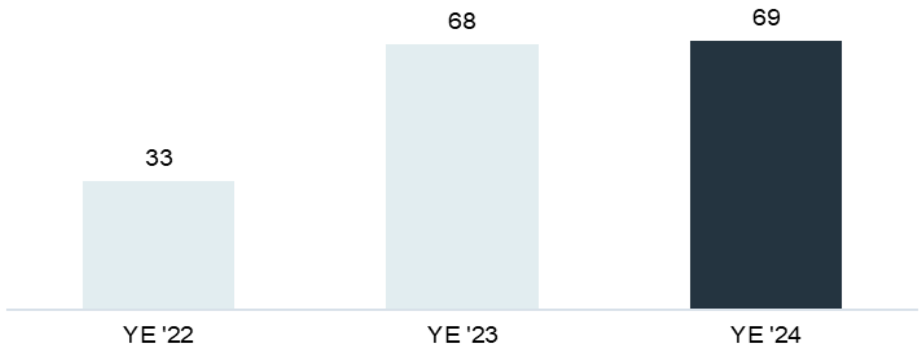
1. Total net proceeds from offering net of underwriting fees but not net of $10.4 million of estimated offering expenses ($7.7 million of which were previously paid).
2. 15.2 million shares of Class A common stock sold in IPO, including the underwriters' full exercise of their over-allotment options.
3. Includes 15.2 million Class A shares plus 45.6 million Class B shares.

Reserves Summary

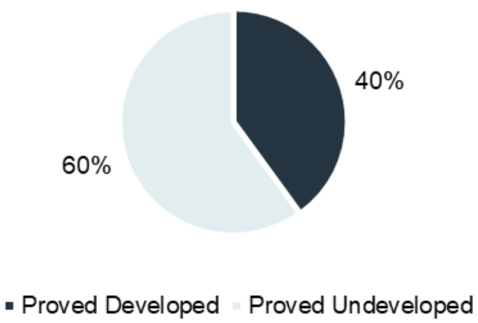
Total Proved Reserves
(Net MMBoe)



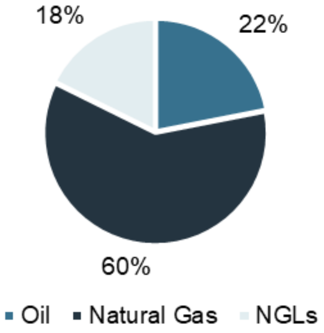
Total Proved Developed Reserves
(Net MMBoe)



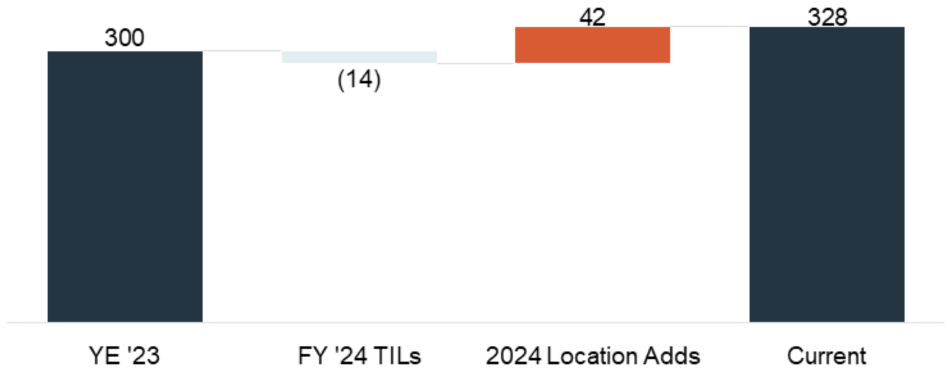
Reserve Categories



Commodity Category



Inventory Replacement
(Stick Count)



Hedge Book Overview

	FY 2025					FY 2026					FY 2027				
	Q1	Q2	Q3	Q4	2025	Q1	Q2	Q3	Q4	2026	Q1	Q2	Q3	Q4	2027
WTI Fixed Price Swaps															
Total Volume (Bbl)	633,800	582,800	551,000	689,600	2,457,200	539,000	438,000	357,000	303,000	1,637,000	-	-	-	-	-
Daily Volume (Bbl/d)	7,042	6,404	5,989	7,496	6,732	5,989	4,813	3,880	3,293	4,485	-	-	-	-	-
Weighted Average Price ($ / Bbl)	$72.99	$72.17	$70.98	$66.24	$70.45	$64.03	$64.10	$64.07	$64.00	$64.05	-	-	-	-	-
Henry Hub Fixed Price Swaps															
Total Volume (MMBtu)	4,657,500	8,972,500	10,729,000	13,204,000	37,563,000	12,751,000	11,810,000	10,590,000	9,504,000	44,655,000	7,497,000	4,670,000	4,398,000	4,109,000	20,674,000
Daily Volume (MMBtu/d)	51,750	98,599	116,620	143,522	102,912	141,678	129,780	115,109	103,304	122,342	83,300	51,319	47,804	44,663	56,641
Weighed Average Price ($ / MMBtu)	$3.87	$3.15	$3.49	$3.96	$3.62	$4.27	$3.54	$3.75	$4.04	$3.90	$4.35	$3.38	$3.60	$3.93	$3.89
Dom South Basis Swaps															
Total Volume (MMBtu)	7,493,500	12,408,500	12,138,500	13,073,500	45,114,000	12,276,000	11,347,000	10,137,000	9,065,000	42,825,000	7,131,000	3,140,000	3,320,000	3,280,000	16,871,000
Daily Volume (MMBtu/d)	83,261	136,357	131,940	142,103	123,600	136,400	124,692	110,185	98,533	117,329	79,233	34,505	36,087	35,652	46,222
Weighed Average Price ($ / MMBtu)	($0.74)	($0.87)	($1.19)	($1.18)	($1.02)	($0.77)	($0.90)	($1.21)	($1.25)	($1.01)	($0.76)	($0.73)	($1.06)	($1.05)	($0.87)
Tetco M2 Basis Swaps															
Total Volume (MMBtu)	536,000	522,000	510,000	500,000	2,068,000	473,000	461,000	451,000	436,000	1,821,000	366,000	-	-	-	366,000
Daily Volume (MMBtu/d)	5,956	5,736	5,543	5,435	5,666	5,256	5,066	4,902	4,739	4,989	4,067	-	-	-	1,003
Weighed Average Price ($ / MMBtu)	($0.58)	($1.02)	($1.30)	($1.32)	($1.05)	($0.58)	($0.96)	($1.19)	($1.25)	($0.99)	($0.58)	$0.00	$0.00	$0.00	($0.58)

Hedge Book Overview

	FY 2025					FY 2026					FY 2027				
	Q1	Q2	Q3	Q4	2025	Q1	Q2	Q3	Q4	2026	Q1	Q2	Q3	Q4	2027
Ethane Fixed Price Swaps															
Total Volume (Gallons)	3,293,000	3,572,500	3,488,000	3,627,000	13,980,500	2,441,000	2,440,000	2,294,000	2,137,000	9,312,000	-	-	-	-	-
Daily Volume (Bbl/d)	871	935	903	939	912	646	638	594	553	607	-	-	-	-	-
Weighted Average Price ($ / Gal)	$0.24	$0.24	$0.25	$0.28	$0.25	$0.28	$0.27	$0.28	$0.29	$0.28	-	-	-	-	-
Propane Fixed Price Swaps															
Total Volume (Gallons)	4,926,000	5,123,500	6,109,500	8,079,500	24,238,500	5,259,000	5,726,000	5,237,000	4,679,000	20,901,000	-	-	-	-	-
Daily Volume (Bbl/d)	1,303	1,341	1,581	2,091	1,581	1,391	1,498	1,355	1,211	1,363	-	-	-	-	-
Weighted Average Price ($ / Gal)	$0.75	$0.71	$0.72	$0.76	$0.74	$0.76	$0.70	$0.69	$0.71	$0.71	-	-	-	-	-
Normal Butane Fixed Price Swaps															
Total Volume (Gallons)	1,831,500	1,786,000	1,811,500	2,372,500	7,801,500	1,547,000	1,698,000	1,558,000	1,395,000	6,198,000	-	-	-	-	-
Daily Volume (Bbl/d)	485	467	469	614	509	409	444	403	361	404	-	-	-	-	-
Weighted Average Price ($ / Gal)	$0.89	$0.83	$0.83	$0.86	$0.85	$0.87	$0.80	$0.80	$0.81	$0.82	-	-	-	-	-
IsoButane Fixed Price Swaps															
Total Volume (Gallons)	1,102,500	1,060,000	1,113,500	1,482,500	4,758,500	951,000	1,032,000	945,000	846,000	3,774,000	-	-	-	-	-
Daily Volume (Bbl/d)	292	277	288	384	310	252	270	245	219	246	-	-	-	-	-
Weighted Average Price ($ / Gal)	$0.91	$0.87	$0.87	$0.89	$0.88	$0.89	$0.83	$0.82	$0.83	$0.84	-	-	-	-	-
Nat Gas Fixed Price Swaps															
Total Volume (Gallons)	1,373,500	1,200,500	1,104,000	954,500	4,632,500	772,000	734,000	600,000	571,000	2,677,000	-	-	-	-	-
Daily Volume (Bbl/d)	363	314	286	247	302	204	192	155	148	175	-	-	-	-	-
Weighted Average Price ($ / Gal)	$1.45	$1.42	$1.39	$1.37	$1.41	$1.40	$1.37	$1.36	$1.35	$1.37	-	-	-	-	-

Non-GAAP Definitions

Adjusted EBITDAX is defined as net income plus interest, net, income tax expense, 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. We believe Adjusted EBITDAX is useful because it makes for an easier comparison of our operating performance, 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.

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. However, our PV-10 for proved reserves using SEC pricing and the Standardized Measure of proved reserves are equivalent because we were not subject to entity level taxation. Accordingly, no provision for federal or state income taxes has been provided in the Standardized Measure because taxable income is passed through to our unitholders.

Capital Efficiency Ratio means Adjusted EBITDAX per unit of production divided by finding and development costs ("F&D") per Boe.

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.

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.

Net debt is defined as total long-term debt minus cash and cash equivalents.

Reconciliation of Adjusted EBITDAX to Net Income

Adjusted EBITDAX Reconciliation

(in thousands, unless specified)

	Three Months Ended Ended September 30,		Nine Months Ended Ended September 30,	
	2025	2024	2025	2024
Net Income	$40,014	$44,789	($16,395)	$54,803
Interest, net	2,290	7,292	6,717	16,263
Income tax expense (benefit)	(3,383)	-	(3,936)	-
Depreciation, depletion, and amortization	27,579	21,067	72,489	56,344
(Gain) loss on derivative instruments	(15,250)	(29,449)	(30,153)	(6,397)
Net cash settlements received (paid) on derivatives	6,374	12,454	5,567	27,755
Non-recurring transaction expenses	172	-	127,191	-
Non-cash compensation expenses	2,253	-	5,301	-
Adjusted EBITDAX	**$60,049**	**$56,153**	**$166,781**	**$148,768**

Reconciliation of PV-10 to Standardized Measure of Oil and Gas

PV-10 Reconciliation

(in thousands, unless specified)

	December 31,		
	2024	2023	2022
Future cash inflows	$4,181,440	$3,865,302	$3,116,373
Future development costs[1]	(652,135)	(545,803)	(273,522)
Future production costs	(1,548,957)	(1,281,802)	(535,779)
Future net cash flows	1,980,348	2,037,697	2,307,072
Discounted future income tax expense	-	-	-
10% discount to reflect timing of cash flows	(1,007,830)	(1,099,313)	(1,289,464)
Standardized measure of discounted future net cash flows	**$972,518**	**$938,384**	**$1,017,608**
Discounted future income tax expense	-	-	-
PV-10	**$972,518**	**$938,384**	**$1,017,608**

Reconciliation of All-In F&D

All-In F&D

(in thousands, unless specified)

	December 31,		
	2024	2023	2022
Acquisition costs:			
Proved properties	$19,172	274,732	2,066
Unproved properties	89,174	1,047	-
Development costs	165,795	144,121	108,544
Exploration costs	-	-	-
	$274,141	**$419,900**	**$110,610**
Reserve Additions:			
Extensions	36,018	44,575	32,256
Revisions to previous estimates	1,559	(24,069)	(5,145)
Purchases of reserves in place	-	48,194	-
Total Reserve Additions	**$37,577**	**$68,700**	**$27,111**
All-In F&D ($ / Boe)	**$7.30**	**$6.11**	**$4.08**

Reconciliation of Capital Efficiency

Capital Efficiency

(in thousands, unless specified)

	December 31,		
	2024	**2023**	**2022**
Adjusted EBITDAX	**$195,719**	**126,494**	**75,971**
Adjusted EBITDAX Margin ($ / Boe)	*$22.20*	*$18.33*	*$23.54*
All-In F&D ($ / Boe)	**$7.30**	**$6.11**	**$4.08**
Capital Efficiency (x)	**3.04x**	**3.00x**	**5.77x**

Reconciliation of Net Debt

Net Debt

(in thousands, unless specified)

	September 30, 2025
Credit Facility Borrowings	$75,363
Total long-term debt	$75,363
Less: Cash and cash equivalents	4,572
Net Debt	**$70,791**