2nd Quarter 2025 Earnings Presentation

August 2025

INFINITY
NATURAL RESOURCES

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 Adjusted EBITDAX Margin[4] 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 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

Key INR Statistics

~125,000[3]
Net Horizon Acres

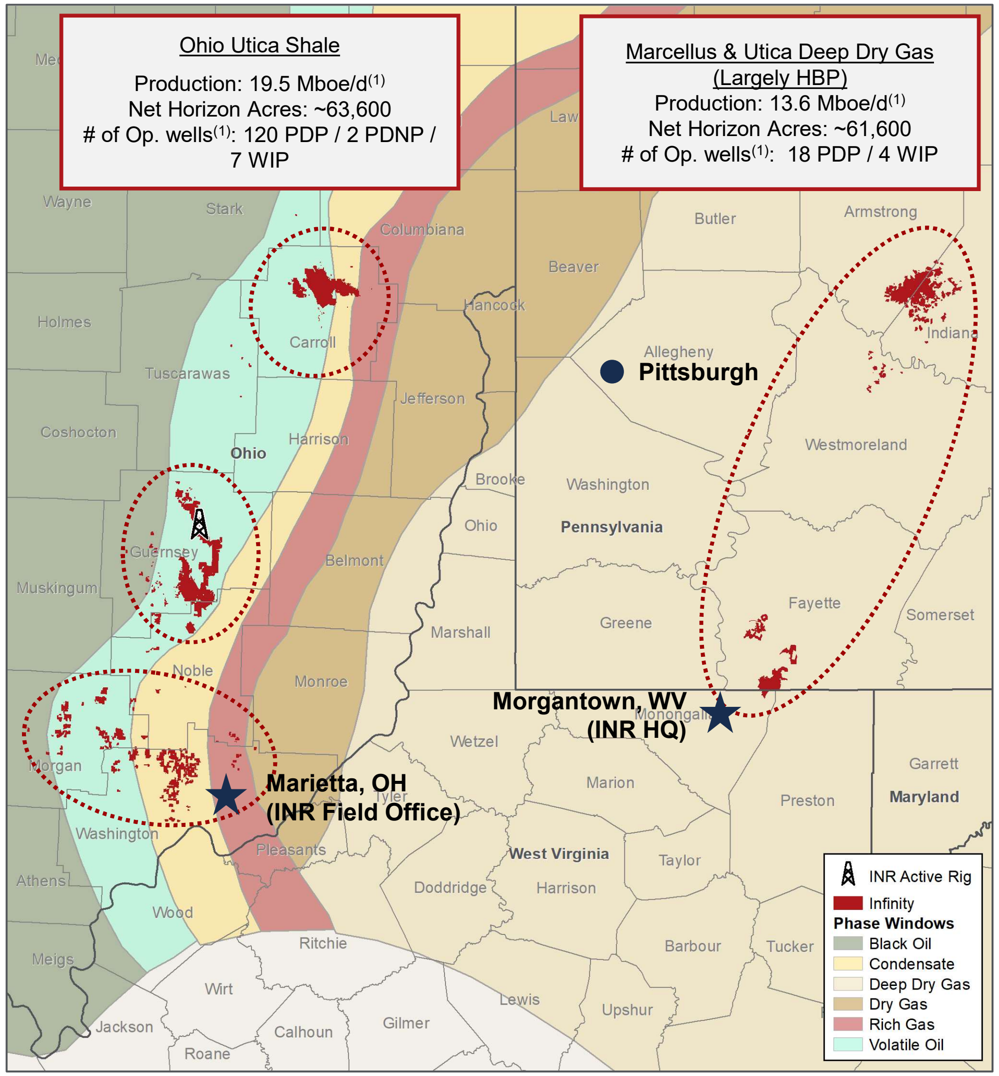
28%
2024 Annual Production Growth

18 Years
High-Quality, Balanced Inventory

~0.1x
Q2'25 Leverage

~$322 million
Total Liquidity

Unique Appalachian Footprint



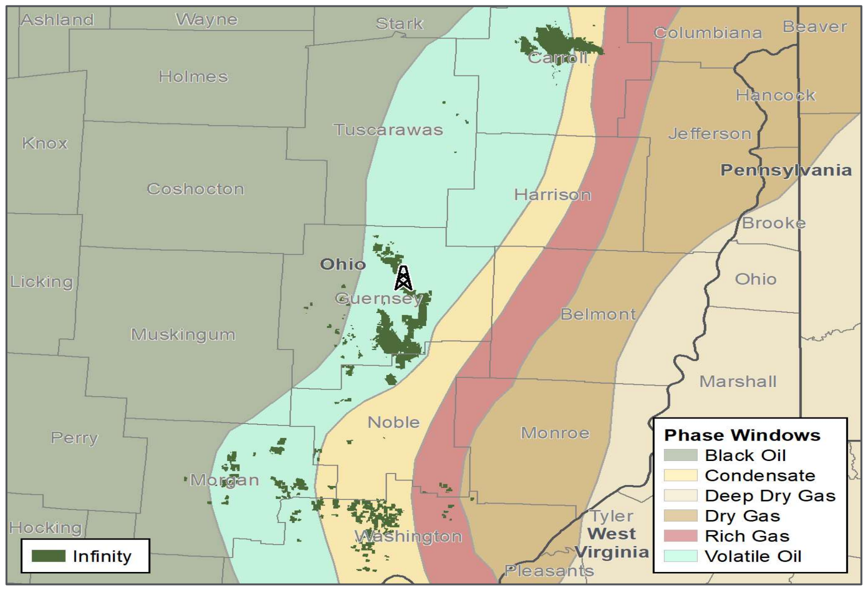
1) As of Q2 2025.
2) Represents the midpoint of the 2025E production guidance range
3) Represents current acreage total
4) Adjusted EBITDAX Margin is a non-GAAP financial measure, see appendix for additional details.

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

152 Locations
2 PDNP & 7 WIPs
2,001 Total Lateral Feet (000s)[1]
Breakeven realized oil price of $27.80 per barrel



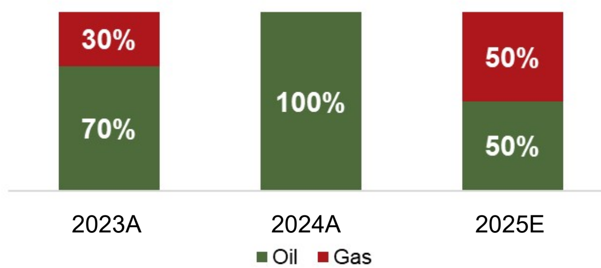
Oil-Weighted Inventory at $3.50 HHUB[2]

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 (%)

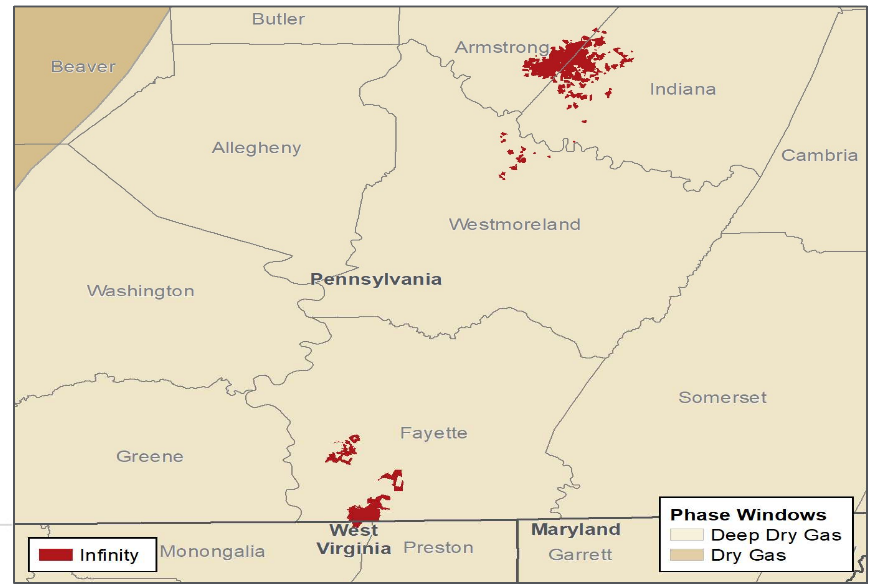


Benchmark Commodity Pricing (WTI/HH)

2023A:	2024A:	2025E:
$70.60	$67.78	$67.74[4]
$2.74	$2.27	$3.46[4]

Gas-Weighted Pennsylvania Dry Gas Marcellus and Deep Dry Gas Utica

173 Locations
4 WIPs
2,252 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

Notes: Normalized to 15,000 ft. Totals as of 6/30/2025.
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 July 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.

Recent Operational Activity

Operational Update

- **Targeting longer laterals efficiently; reducing costs, enhancing returns**
- **Operated two rigs and two frac fleets for much of Q2'25, busiest quarter on record**
  - Dropped to one rig in May and one frac fleet in July, as planned
- **Turned into sales one oil well in May**
  - Well operated at restricted flow due to third-party midstream constraints through Q2'25 but is free flowing as of July
- **Seven wells drilled: 3 PA Marcellus gas wells; 4 OH Utica oil wells**
  - Continuing to develop long lateral inventory with five longest laterals drilled in company history
- **Eight wells stimulated: 777 stages (4 PA Marcellus gas wells, 4 OH Utica oil wells)**
  - Average ~9 stages per day; 48% more stages in Q2'25 than prior INR record
- **New natural gas pad constructed in PA, with 4.3 miles of roadway upgraded**
  - Decision made to pull project forward during Q2'25
  - Commenced drilling 3-well, ~45k lateral foot pad in PA Marcellus in July
- **13 total WIPs exiting Q2'25 (2 PDNP & 7 WIPs OH oil wells, 4 WIPs PA gas wells)**
  - Since Q2'25-end, turned into sales six wells (2 OH oil wells, 4 PA gas wells)
  - Anticipate turning to sales additional oil weighted project in OH in Q3'25

Pennsylvania Drilling Operations

Ohio Stimulation Operations

2nd Quarter 2025 Highlights

Highlights

- Continued development activity during quarter:
  - Drilled 7 wells and completed 8 wells with 13 WIPs at 6/30
  - Drilled ~119k lateral feet while completing 777 stages
  - Drilled the longest well in company history at ~22,500'
- Turned online one oil-weighted well
- 2 PDNP at end of quarter; six additional wells online by July
- Constructed additional gas pad location in Pennsylvania
- Production mix shifted higher during quarter to natural gas due to:
  - Strength of recent Marcellus pad in Pennsylvania
  - Increased ethane recovery in Ohio
  - Midstream constraints on Rubel pad location in Ohio (all wells online and producing by July 25)
- Constructed ~2 miles of permanent gas and water infrastructure to support future development
- Recorded company TRIR of 0.0
- Added ~2k acres in close proximity to existing acreage in Ohio and Pennsylvania
- Maintained low leverage and financial liquidity

Financial Highlights

	Q2 2025	Q2 2024
Total Production Volumes	**33.1** *Mboe/d*	**25.2** *Mboe/d*
Net Revenues	**$74.5** *million*	**$70.4** *million*
Operating Costs(1)	**$23.9** *million*	**$19.2** *million*
Adjusted EBITDAX(2)	**$49.6** *million*	**$49.8** *million*
Incurred Capital Expenditures(3)	**$73.1** *million*	**$31.9** *million*
Leverage (Debt / Adj. EBITDAX)(2)	**~0.1x**	**0.9x**

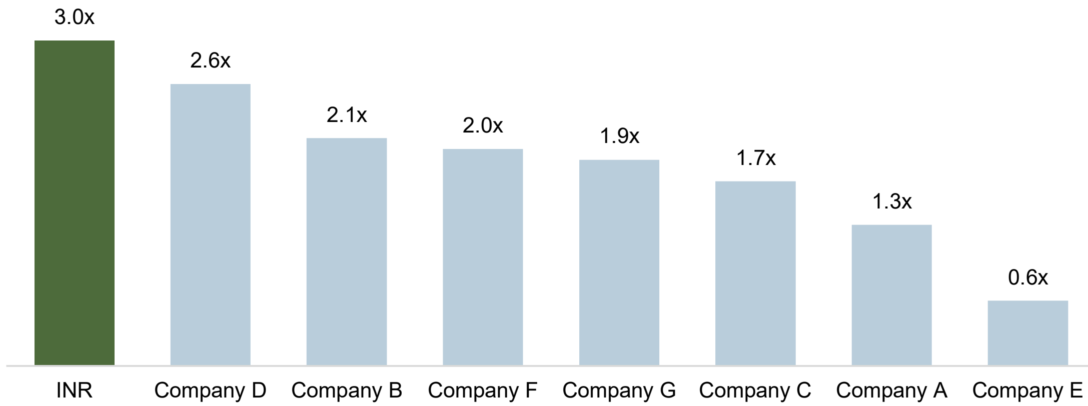
1) Includes LOE , GP&T and taxes other than income.
2) Adjusted EBITDAX is a non-GAAP financial measure, see appendix for additional details.
3) Includes incurred D&C capital expenditures along with midstream capital expenditures for the respective period.

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

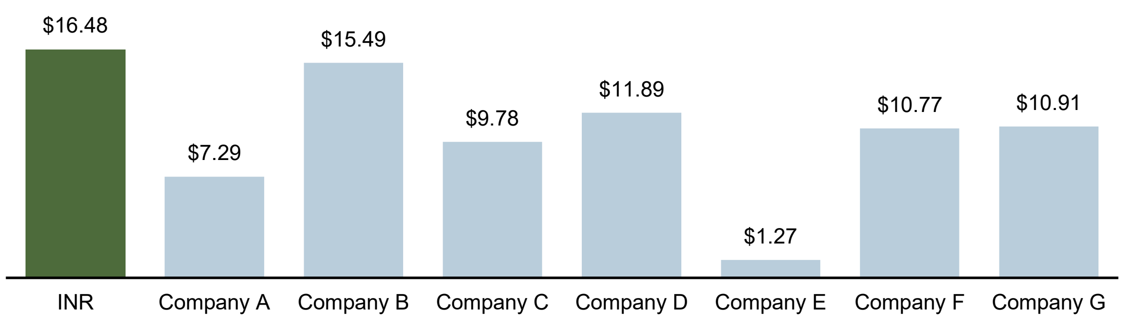
2024A Capital Efficiency Ratio[1][2]

(x)



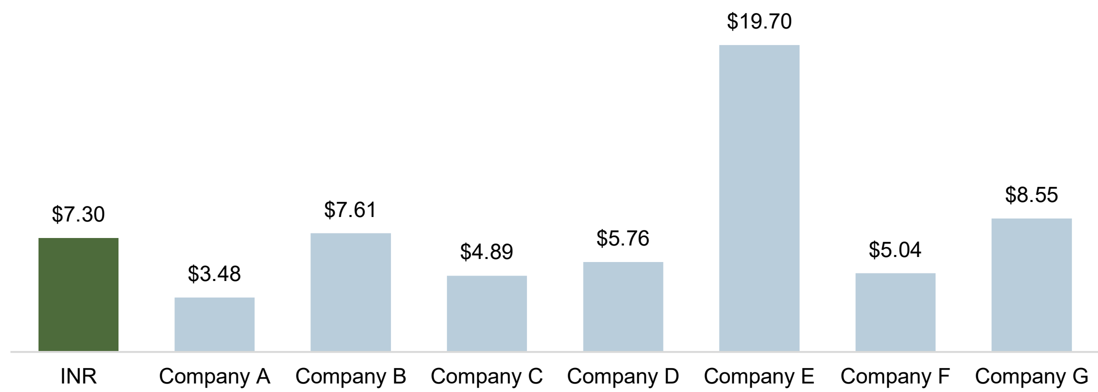
2nd Quarter 2025A Adjusted EBITDAX Margin[1][2]

($ / 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.

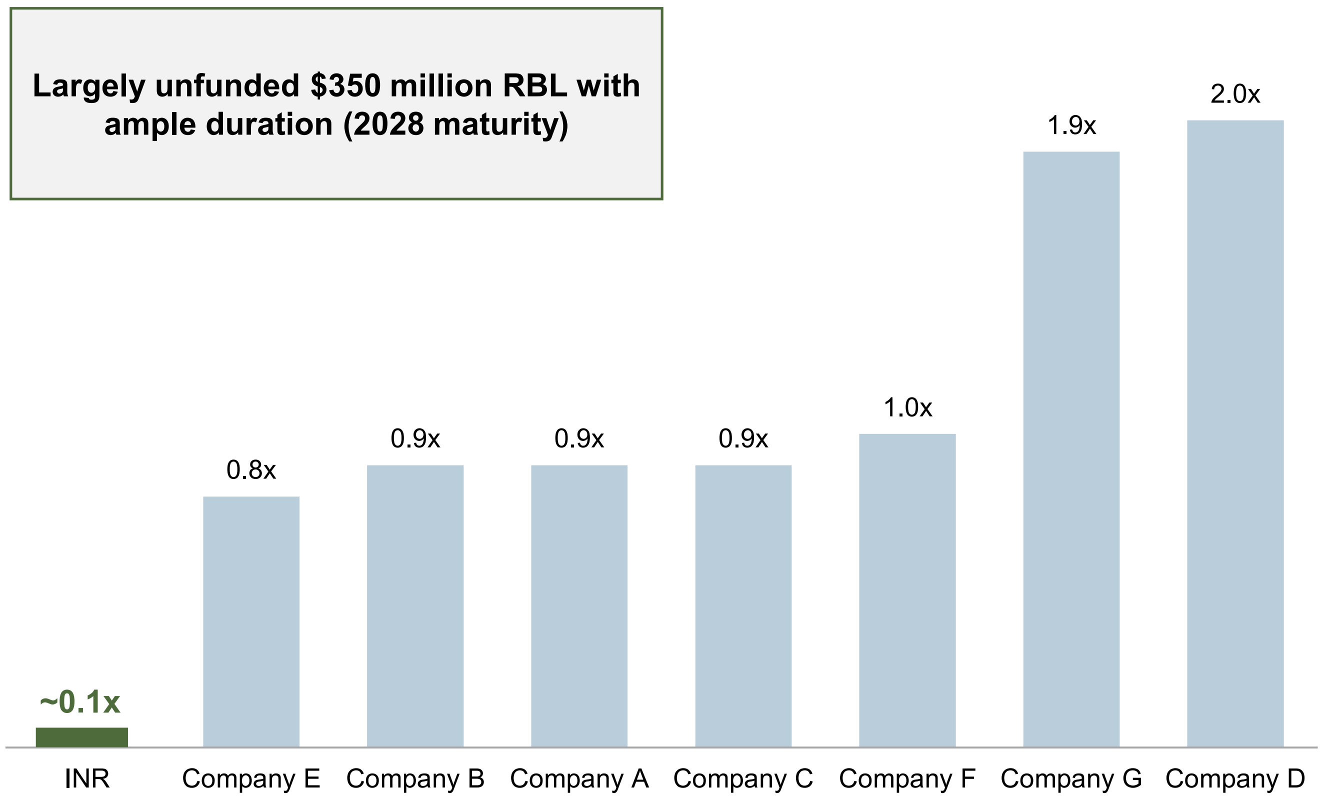
Low Leverage Provides Operational and Financial Flexibility

Financial Profile and Commentary

- **<u>Target net leverage of less than 1.0x</u>**
  - 2nd quarter 2025 leverage of 0.1x[1] provides financial flexibility and derisks development plan
- **<u>2nd quarter 2025 liquidity of ~$322 million</u>**
  - ~$6 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

Leverage Benchmarking vs Select Natural Gas Peers

2nd Quarter 2025 Net Debt[1] / Q2'25A Adjusted EBITDAX[1][2]
(x)



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

2025 Outlook and Guidance

Drilling & Completion Capital Expenditures:

$240 million - $280 million

Midstream Capital Expenditures:

$9 million - $12 million

Total Net Daily Production:

32 - 35 MBoe/d

Representing growth of approximately 40% over 2024 at the midpoint of the range

Development Plan:

Anticipate running 1.2 operated rigs throughout the year

Environmental, Social and Governance

Infinity's ESG Focus	Achievements
Diligent Tracking and Reporting *Modern Facility Design* *Water Recycling and Sharing* *Charitable Contributions* *Community Support*	• 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 • Zero Infinity employee Days Away, Restricted, or Transferred (DART) 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

INFINITY
NATURAL RESOURCES

Initial Public Offering Highlights

INR LISTED NYSE

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

$286 million[(1)]
in Proceeds

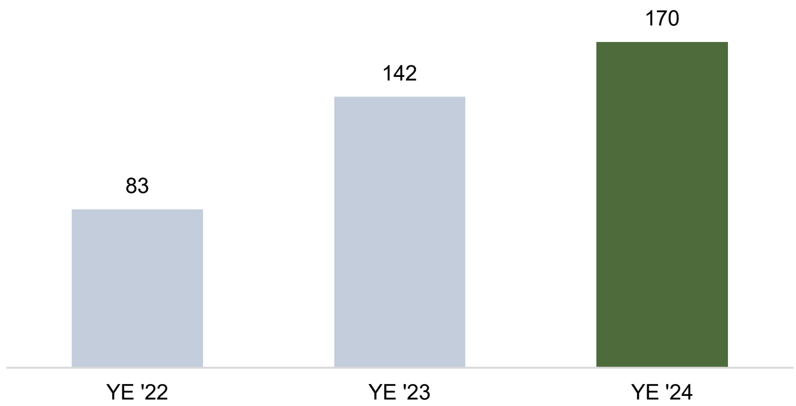
15.2 million[(2)]
Shares Issued via IPO

60.9 million[(3)]
Total Shares Outstanding

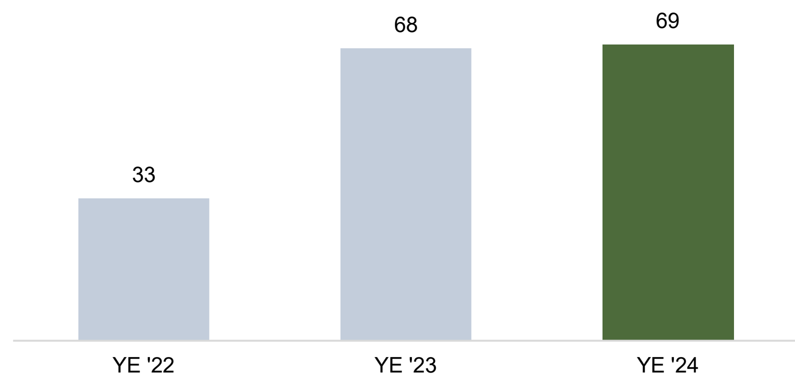
(1) Total net proceeds from offering net of underwriting fees, but not net of $10.4 million of estimated offering expenses ($7.7 million of which were previously paid).
(2) 15.2 million shares of Class A common stock sold in IPO, including the underwriters' full exercise of their over-allotment options.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

Reserves Summary

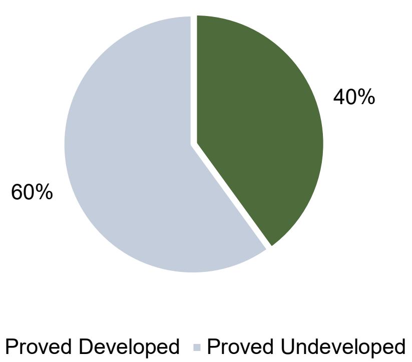
Total Proved Reserves
(Net MMBoe)



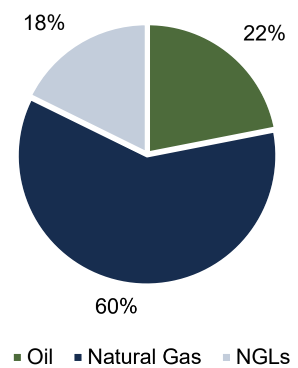
Total Proved Developed Reserves
(Net MMBoe)



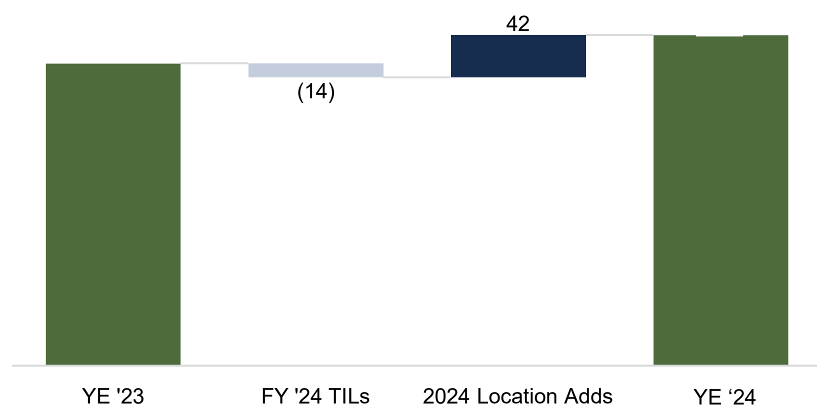
Reserve Categories[1]



Commodity Category[1]



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	297,000	249,000	216,000	190,000	952,000	-	-	-	-	-
Daily Volume (Bbl/d)	7,042	6,404	5,989	7,496	6,732	3,300	2,736	2,348	2,065	2,608	-	-	-	-	-
Weighted Average Price ($ / Bbl)	$72.99	$72.17	$70.98	$66.24	$70.45	$65.11	$65.38	$65.36	$65.24	$65.26	-	-	-	-	-
Henry Hub Fixed Price Swaps															
Total Volume (MMBtu)	4,657,500	8,972,500	12,007,000	14,179,000	39,816,000	13,710,000	12,651,000	11,345,000	10,190,000	47,896,000	7,497,000	4,670,000	4,398,000	4,109,000	20,674,000
Daily Volume (MMBtu/d)	51,750	98,599	130,511	154,120	109,085	152,333	139,022	123,315	110,761	131,222	83,300	51,319	47,804	44,663	56,641
Weighed Average Price ($ / MMBtu)	$3.87	$3.15	$3.49	$3.95	$3.62	$4.26	$3.53	$3.74	$4.05	$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)

Note: As of 07/30/25

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		-	-	-	-	-

Note: As of 07/30/25

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 June 30,		Six Months Ended Ended June 30,	
	2025	**2024**	**2025**	**2024**
Net Income	$71,954	$24,070	($56,409)	$10,014
Interest, net	(1,360)	(4,398)	(4,427)	(8,971)
Income tax expense (benefit)	(588)	-	(569)	-
Depreciation, depletion, and amortization	23,652	19,722	44,910	35,277
(Gain) loss on derivative instruments	(52,121)	(403)	(14,903)	23,052
Net cash settlements received (paid) on derivatives	2,778	2,038	(808)	15,301
Non-recurring transaction expenses	331	-	127,190	-
Non-cash compensation expenses	2,293	-	3,048	-
Adjusted EBITDAX	**$49,658**	**$49,825**	**$106,887**	**$92,615**

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**

(1) Future development costs include costs associated with the future abandonment of proved properties, including proved undeveloped locations.

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**