Investor Presentation

November 2025

Forward Looking Statements & Non-GAAP Financial Measures

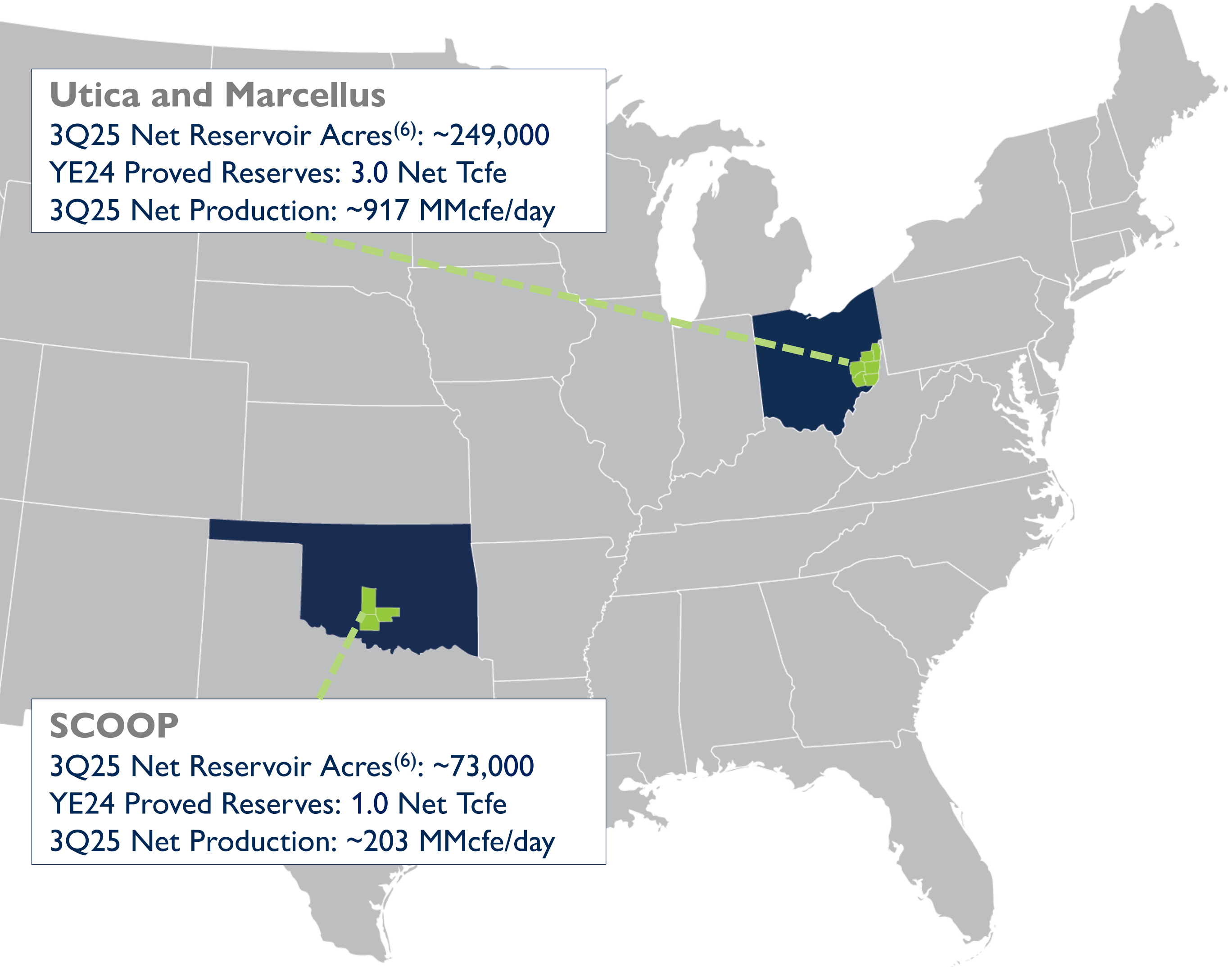
This presentation contains "forward-looking statements" within the meaning of Section 27A of the Securities Act, Section 21E of the Exchange Act, and the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements by terms such as "may," "will," "should," "could," "would," "expects," "plans," "anticipates," "intends," "believes," "estimates," "projects," "predicts," "potential" and similar expressions intended to identify forward-looking statements. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that we expect or anticipate will or may occur in the future, including the expected impact of U.S. trade policy and its impact on broader economic conditions, the war in Ukraine and the conflict in the Middle East on our business, our industry and the global economy, estimated future production and net revenues from oil and gas reserves and the present value thereof, future capital expenditures (including the amount and nature thereof), share repurchases, business strategy and measures to implement strategy, competitive strength, goals, expansion and growth of our business and operations, plans, references to future success, reference to intentions as to future matters and other such matters are forward-looking statements. These forward-looking statements are largely based on our expectations and beliefs concerning future events, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors relating to our operations and business environment, all of which are difficult to predict and many of which are beyond our control. Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in this presentation are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in Item 1A. "Risk Factors" and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Gulfport's Annual Report on Form 10-K for the year ended December 31, 2024, Item 2. "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Gulfport's Quarterly Reports on Form 10-Q and all forward-looking statements speak only as of the date of this presentation.

Gulfport's proved reserves and adjusted proved reserves are those quantities of natural gas, oil, and natural gas liquids, 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, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Gulfport's estimate of its total proved reserves are internally generated and audited by Netherland, Sewell Associates, Inc., independent petroleum engineers. Factors affecting ultimate recovery include the scope of Gulfport's ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, actual drilling results, including geological and mechanical factors affecting recovery rates, and other factors. Estimates may change significantly as development of Gulfport's natural gas, oil and natural gas liquids assets provide additional data. Gulfport's production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Gulfport's management uses certain non-GAAP financial measures for planning, forecasting and evaluating business and financial performance, and believes that they are useful tools to assess Gulfport's operating results. Although these are not measures of performance calculated in accordance with generally accepted accounting principles (GAAP), management believes that these financial measures are useful to an investor in evaluating Gulfport because (i) analysts utilize these metrics when evaluating company performance and have requested this information as of a recent practicable date, (ii) these metrics are widely used to evaluate a company's operating performance, and (iii) we want to provide updated information to investors. Investors should not view these metrics as a substitute for measures of performance that are calculated in accordance with GAAP. In addition, because all companies do not calculate these measures identically, these measures may not be comparable to similarly titled measures of other companies. These non-GAAP financial measures include adjusted EBITDA, adjusted free cash flow, recurring general and administrative expense and present value of estimated future net revenue. A reconciliation of each financial measure to its most directly comparable GAAP financial measure is included as part of this presentation. These non-GAAP measures should be considered in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

Gulfport Energy Overview



Utica and Marcellus
3Q25 Net Reservoir Acres[6]: ~249,000
YE24 Proved Reserves: 3.0 Net Tcfe
3Q25 Net Production: ~917 MMcfe/day

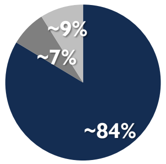
SCOOP
3Q25 Net Reservoir Acres[6]: ~73,000
YE24 Proved Reserves: 1.0 Net Tcfe
3Q25 Net Production: ~203 MMcfe/day

Key Highlights

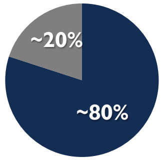
NYSE:	**GPOR**
Market Cap[1]:	**$3.5 Billion**
Enterprise Value ('EV')[2]:	**$4.2 Billion**
EV / 2026 EBITDA[2,7]:	**4.2x**
Liquidity[3]:	**~$903 Million**
Leverage[4]:	**~0.81x**
Operated Base D&C Capital:	~$355 Million
Maintenance Leasehold Capital:	~$35 Million
2025E Total Base Capital:	**~$390 Million**
2025E Total Net Equivalent Production:	**~1,040 MMcfe/day**
~89% Natural Gas	
Top-decile adjusted free cash flow yield[5] relative to natural gas peers	
Remaining Inventory:	**~700 gross operated**
~15 years of net inventory at attractive rates of return	

2025E Activity

2025E Base Capital Program



2025E Production Mix



1. Market capitalization calculated as of 10/29/25 at a price of $181.02 per share using shares outstanding from the Company's 3Q2025 10-Q filing.
2. Enterprise value calculated as of 10/29/25 at a price of $181.02 per share using shares outstanding, long-term debt and cash and cash equivalents from the Company's 3Q2025 10-Q financial statements.
3. As of 9/30/25 and calculated as $3.4 million cash plus $900.3 million borrowing base availability, which takes into effect $51.0 million of borrowings on revolver and $48.7 million of letters of credit.
4. As of 9/30/25 using net debt to LTM Adjusted EBITDA. Net debt and Adjusted EBITDA are non-GAAP measures. Net debt is defined as total long-term debt minus cash and cash equivalents.
5. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Adjusted free cash flow excludes discretionary acreage acquisitions and common stock repurchases. Adjusted free cash flow yield is calculated using adjusted free cash flow divided by market capitalization using shares outstanding from the Company's 3Q2025 10-Q filing.
6. Appalachia acreage includes ~214,000 Utica and ~35,000 Marcellus net reservoir acres. SCOOP acreage includes ~43,000 Woodford and ~30,000 Springer net reservoir acres.
7. EBITDA estimate sourced from Factset as of 10/29/25.

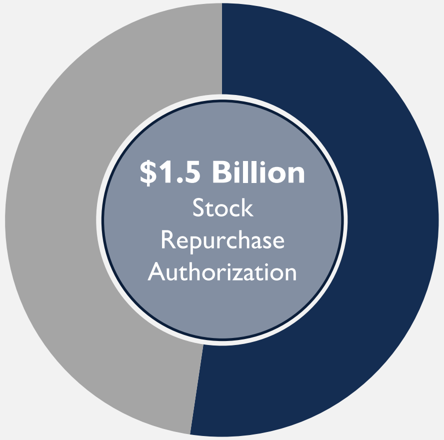
Focused Strategy and Compelling Valuation

High Quality Asset Base Natural Gas Weighted with Liquids Opportunities	• Multi-basin portfolio provides diversification and capital allocation optionality • Capture value accretion through significant expansion of undeveloped inventory, driven by targeted discretionary acreage acquisitions, Marcellus delineation and U-development initiatives • Low breakeven inventory supports sustainable returns and adjusted free cash flow[1] generation
Improve Margins and **Free Cash Flow Generation**	• Focus on continuously improving cycle times and reducing operating costs • Top decile adjusted free cash flow[1] yield and positive adjusted free cash flow[1] across wide range of commodity prices
Enhance Shareholder Value through Disciplined Capital Allocation	• Consistent shareholder return framework returning capital to shareholders through repurchase of undervalued equity • Reinvest in strategic acquisition opportunities that provide operating synergies, quality resource depth and optionality to our near-term development activities
Maintain **Strong Balance Sheet**	• Maintain financial strength and flexibility to execute strategic and operating plans in volatile commodity environment • Hedging program reduces commodity risk and future cash flow volatility
Committed to **Responsible Stewardship**	• Achieved overall "A" rating for Appalachia assets from MiQ for third consecutive year • Safety of employees, contractors and communities is our highest priority • Provide community support through giving and volunteering in our operating areas

1. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Excludes discretionary acreage acquisitions and common stock repurchases.

Delivering Value For Shareholders

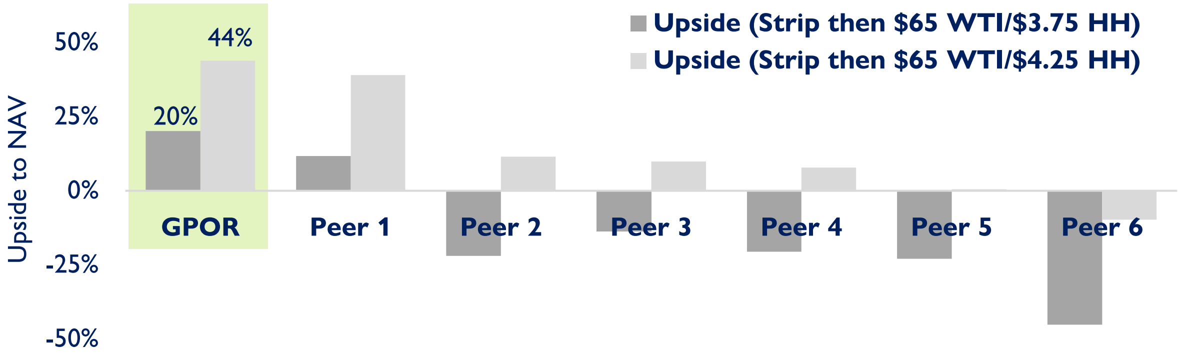
Equity Repurchase Program



Equity Repurchases

- Consistent shareholder return framework and equity repurchase program authorizes purchases up to $1.5 billion
  - On September 5, 2025, redeemed Company's outstanding preferred stock for ~$31.3 million
  - As of September 30, 2025, ~$785 million[4] returned to shareholders since March 2022 at an average price of $117.45 per share
- Expect to repurchase ~$325 million of Gulfport's outstanding equity during 2025, inclusive of ~$125 million planned for 4Q2025

NAV Valuation Upside to Current Share Price[2]

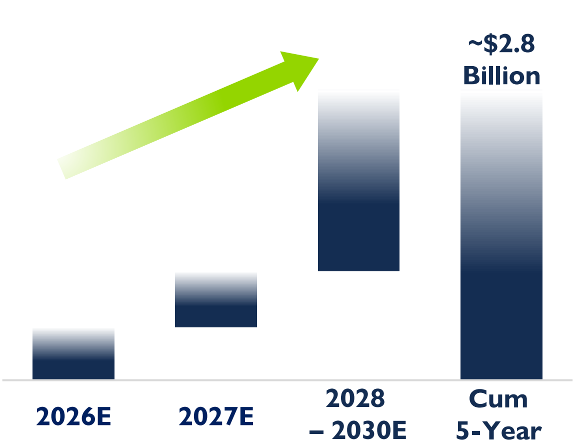


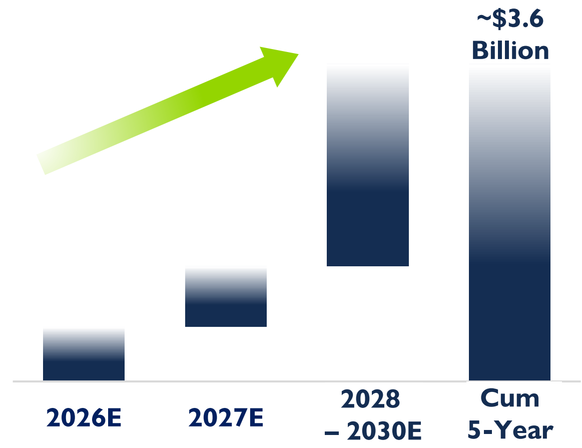
Return of Capital ($MM)	FY 2023	FY 2024
Annual adjusted free cash flow[1]	**$199**	**$257**
Less: discretionary acreage acquisitions	($48)	($45)
Less: equity repurchases executed	($149)	($203)[3]
Remaining adjusted free cash flow[1] available	**$2**	**$9**
% of adjusted free cash flow returned to shareholders	***99%***	***96%***

1. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Excludes discretionary acreage acquisitions and common stock repurchases.
2. Sourced from Enverus Intelligence 2Q2025 Gas NAV Compass. All mentions of NAV are on a post-tax basis. Utilized strip prices as of 9/11/25 and share prices as of 10/20/25. Peers include AR, CNX, CRK, EQT, EXE & RRC.
3. Includes $18.4 million to satisfy tax withholding requirements incurred upon vesting of initial emergence performance stock units granted to certain executive officers in 2021.
4. Includes redemption of preferred equity totaling $31.3 million for ~180,000 shares of common stock on an as-converted basis based on redemption price of $174.22.

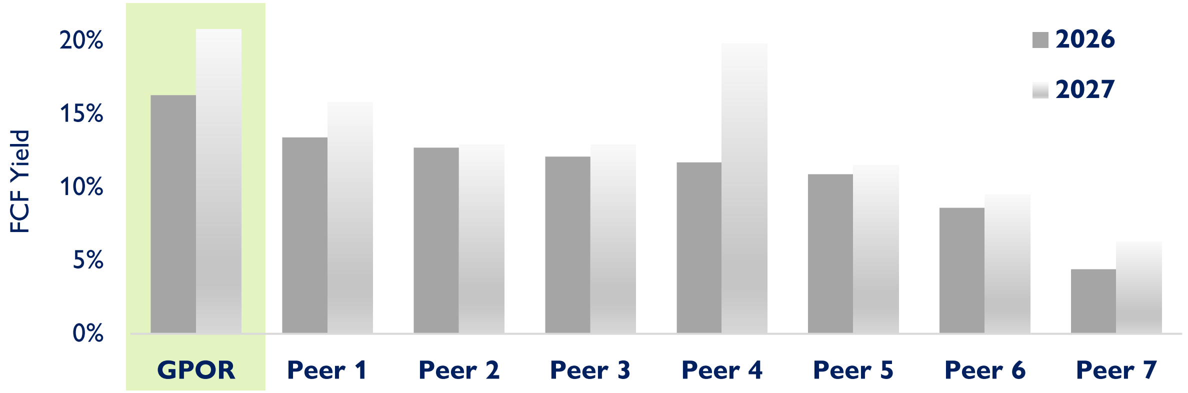
Adjusted Free Cash Flow Generation Potential

2026E – 2030E Adjusted Free Cash Flow(1,2,3) Illustration ($MM)





Adjusted Free Cash Flow Yield(4,5)



Key Highlights

- Sustainable free cash generation underpinned by high-quality assets
- Meaningful adjusted free cash flow profile **generating ~80% - 110% of market capitalization(6)** over the next five years
- Delivering highest adjusted free cash flow yield among natural gas peers
- The focus on maintenance leasehold and land spend, in combination with our discretionary acreage acquisitions, have bolstered our future drilling programs and lowered our go-forward maintenance land spend

	Base Assumptions	Upside Potential
Net Production:	Low single digit growth of 0% – 5%	*Improving base decline, reduced cycle times, potential uplift from managed pressure programs and increase in liquids production*
Cash Costs:	$1.32 – $1.43 / Mcfe	*Reducing per unit cash costs which includes LOE, GP&T, taxes other than income and G&A*
Total Base Capital:	~$355 MM Operated Base D&C ~$35 MM Maintenance Land	*Continued efficiencies, cost reductions and lower maintenance land spend*
Differentials:	Natural Gas: $0.20 - $0.35 off NYMEX Oil: $5.50 - $6.50 off WTI NGL: 40% - 50% of WTI	*Optimizing marketing strategy to improve sales points reached and realizations*
Commodity Prices:	Flat price scenarios	*Commodity price improvements*

1. Adjusted free cash flow is a non-GAAP financial measure; see supplemental slides. Excludes discretionary acreage acquisitions and common stock repurchases.
2. Based upon flat price cases and base assumptions per year. Includes current hedge position as of 10/29/25.
3. No payment of cash income taxes assumed in illustration. Company does not currently anticipate paying significant cash income taxes over next five years (*estimating <10% of cumulative 5-year adjusted free cash flow*).
4. Sourced from J.P. Morgan E&P Valuation Analysis utilizing J.P. Morgan estimates & Bloomberg Finance L.P.; Strip pricing as of 10/23/25 ($60.12/$60.12 per bbl WTI & $4.01/$3.95 per MMBtu NYMEX gas in 2026-27); Share prices as of 10/23/25. Peers include AR, CNX, CTRA, EQT, EXE, NFG, & RRC.
5. Adjusted FCF Yield is calculated using estimated adjusted free cash flow divided by current market capitalization.
6. Market capitalization calculated as of 10/29/25 at a price of $181.02 per share using shares outstanding from the Company's 3Q2025 10-Q filing.

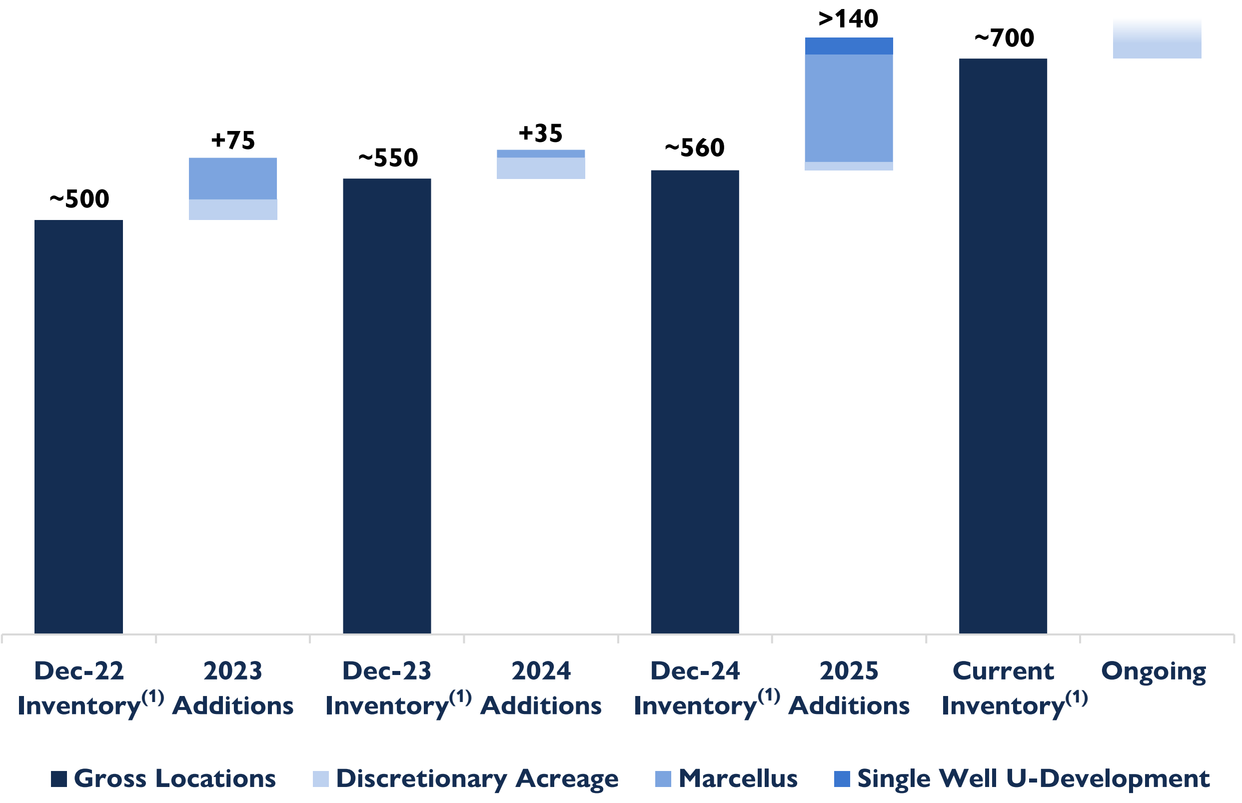
Significant Low Break-Even Inventory Expansion

Key Highlights

- Since year-end 2022, Gulfport's gross undeveloped inventory has increased by more than 40%, driven by targeted discretionary acreage acquisitions, Marcellus delineation and U-development initiatives
- Estimate ~700 gross locations and roughly 15 years of net inventory with break-evens below $2.50 per MMBtu
- Continue to focus on inventory expansion and reiterate plans to invest $75 million to $100 million on discretionary acreage acquisitions by end of 1Q2026, expanding net inventory by incremental ~2 years[1]

>40% Increase in Gross Undeveloped Inventory Since 2022[1]

Continuously adding high-quality inventory through acquisition, delineation and optimization

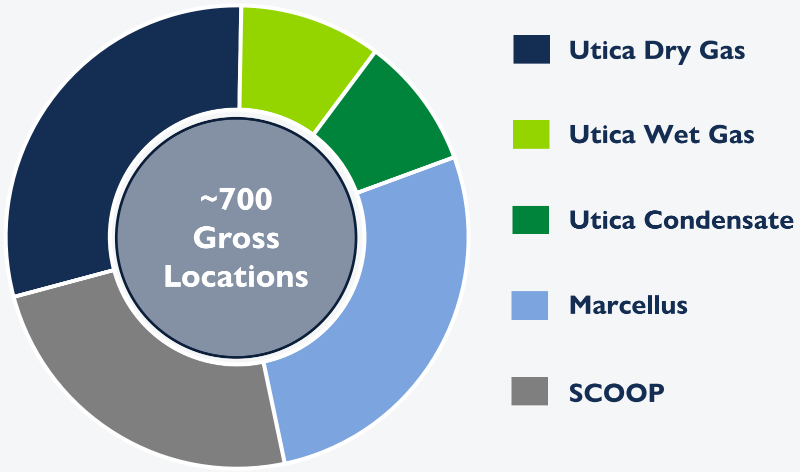


Gross Undeveloped Inventory

High-quality, multi-basin portfolio

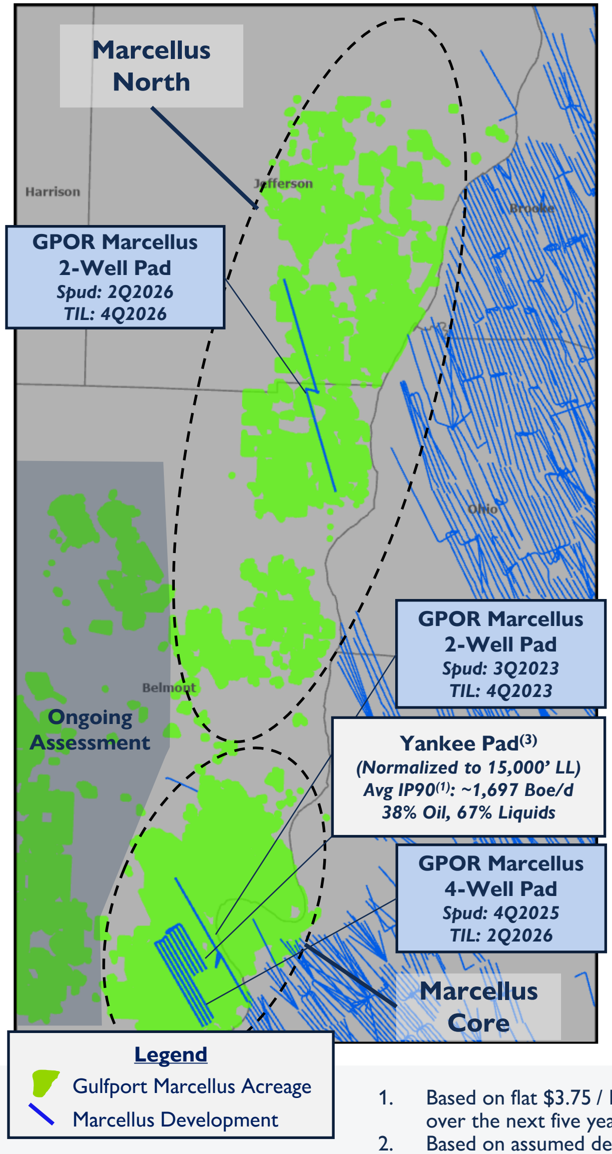
~700 Gross Locations

~15 years[2] net inventory breaks even under $2.50/MMBtu[3]



1. Year-end inventory adjusted for annual development activity.
2. Based on assumed development cadence of approximately 20 to 25 wells per year.
3. PV-10 breakeven price includes all-in wells costs, gathering, processing, transport, pricing differentials, LOE and production taxes. WTI realization used for the analysis was $65/Bbl.

Inventory Expansion in Ohio Marcellus



Key Highlights

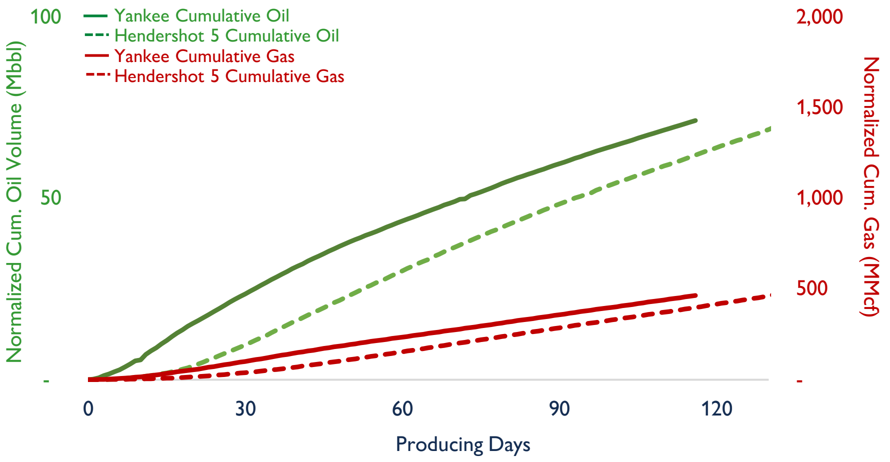
- Recent peer activity combined with Gulfport's previous development has expanded Marcellus resource viability to the northern extent of Gulfport's Ohio acreage
- Total Marcellus inventory increased by ~200%, expanding to ~170 – 190 gross locations
  - Locations added at no incremental land cost
- Second Ohio Marcellus Core development, the Yankee 4-well pad, is exhibiting attractive performance compared to historic results
- Planning Marcellus North 2-well development in 2026

	Gross Locations	Net Locations	Average Lateral Length	Average IRR[1]
Marcellus Core	50 – 60	45 – 50	~15,000'	~80%
Marcellus North	120 - 130	50 – 55	~18,000'	~70%
Total	**170 - 190**	**95 – 105**		

Marcellus development and delineation capturing significant value and >4 years[2] of drillable inventory

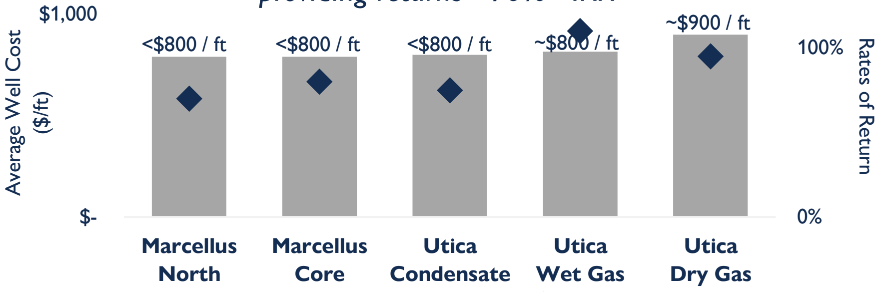
Recent Marcellus Core Well Performance

Average Pad Well Performance Normalized to 15,000' Lateral



Attractive Rates of Return[1]

Utica dry gas, Utica liquids and Marcellus providing returns ~70%+ IRR



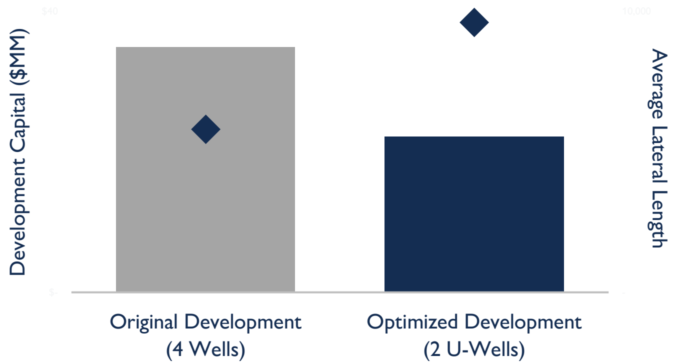
1. Based on flat $3.75 / MMBtu natural gas and $65 / Bbl oil. Average internal rates of returns based on actual planned lateral lengths and type curves for each defined development area over the next five years of development.
2. Based on assumed development cadence of approximately 20 to 25 wells per year.
3. Production rate normalized to 15,000 ft lateral and assumes ethane recovery per Gulfport's gathering contracts.

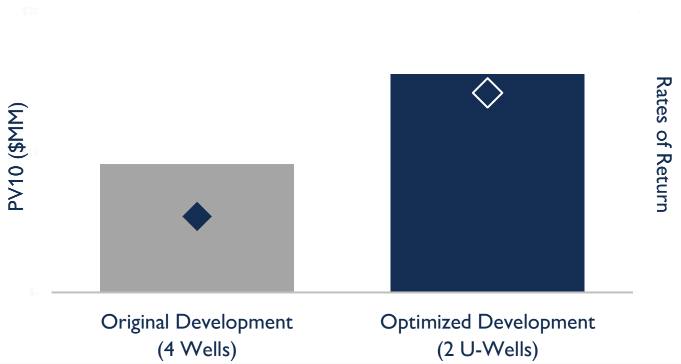
Inventory Expansion Through U-Development

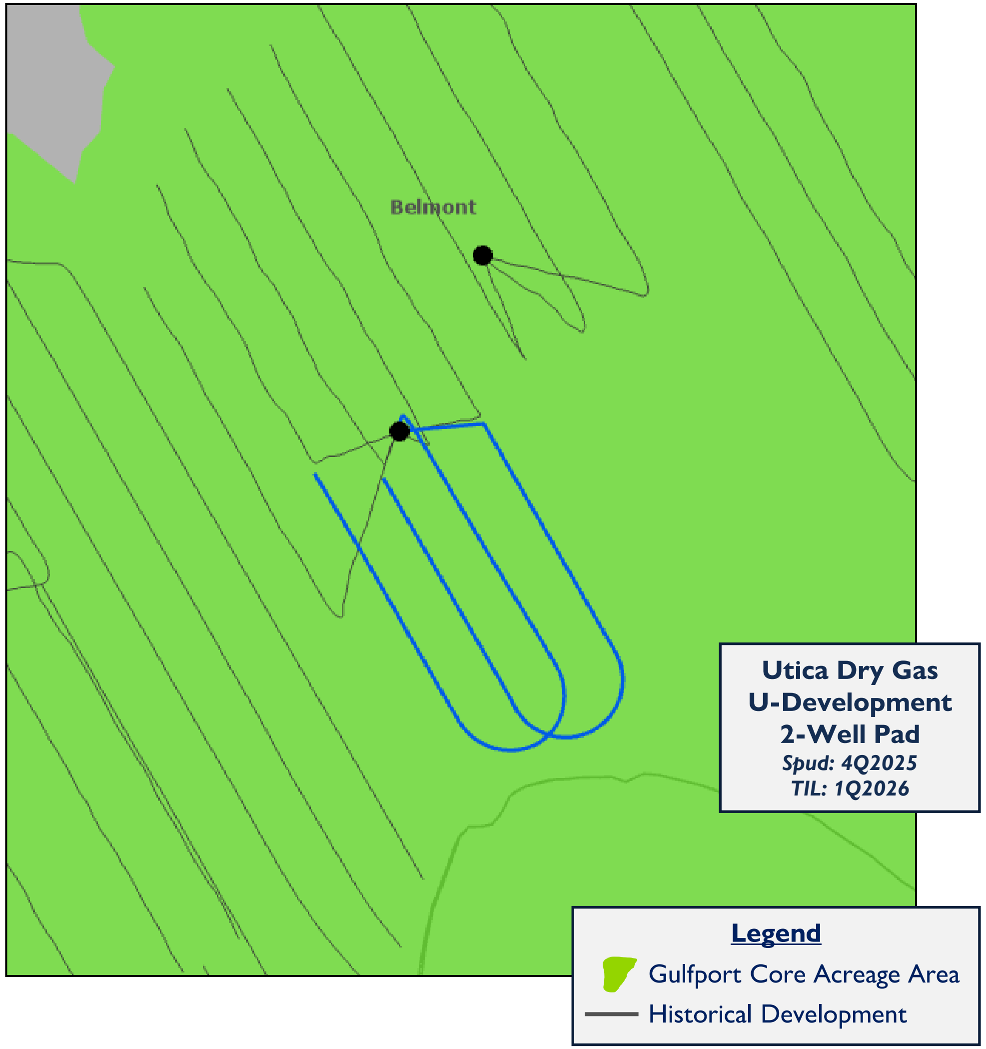
Key Highlights

- Applying operational best practices to optimally develop acreage and enhance economics compared to short lateral development
- Recently reached total depth on first two U-development wells, located in the core dry gas window of eastern Belmont County and validating technical feasibility of U-development across acreage position
  - Original development consisted of four wells <6,000' laterals which did not exceed current economic hurdle rates
  - Redesigned as U-development, resulting in significantly improved capital efficiency and value
  - To date, identified ~20 gross high-return U-development locations

Illustrative Development Comparison[1]







1. Based on flat \$3.75 / MMBtu natural gas and \$65 / Bbl oil and specific development highlighted in map above.

Third Quarter 2025 Results

	3Q2025	YTD2025
Total Net Production	**1,119.7 MMcfe/day**	**1,019.1 MMcfe/day**
Total Liquids Net Production	**22.0 MBbls/day**	**18.8 MBbls/day**
Incurred Base Capital Expenditures(1)	**$74.9 Million**	**$352.7 Million**
Per Unit Operating Cost(2)	**$1.21 per Mcfe**	**$1.25 per Mcfe**
Adjusted Free Cash Flow(3)	**$103.4 Million**	**$204.6 Million**
Common Stock Repurchases	**$76.3 Million**	**$201.3 Million**
Discretionary Acreage Acquisitions	**$8.9 Million**	**$15.7 Million**
Quarter-end Leverage (Net Debt(4) to Adjusted EBITDA(3))	**0.81x**	

Key Highlights

- Expanded undeveloped Marcellus inventory by ~125 gross locations, an increase of 200% in Ohio Marcellus inventory
- Total net inventory of ~15 years with break-evens below $2.50 per MMBtu
- Investing incremental discretionary appraisal capital to successfully test the drilling feasibility of U-development in the Utica, unlocking 20 gross Utica dry gas locations
- Investing incremental spend toward discretionary development activity to mitigate anticipated production impacts from offset operator simultaneous operations and planned midstream maintenance downtime in early 2026
- Delivered total net production of 1,119.7 MMcfe per day, an increase of 11% over second quarter 2025
- Yankee development, four-well Marcellus Core pad, exhibiting attractive performance following >90 days online
- Reiterate plans to invest ~$75 - $100 million toward discretionary acreage acquisitions, of which $15.7 million was deployed at the end of 3Q2025
- Repurchased 6.7 million shares of common stock for ~$785 million[5] since March 2022
- Plan to allocate ~$125 million to common stock repurchases in the fourth quarter of 2025 while maintaining leverage at or below one times

1. Excludes $12.4 million of discretionary capital, $1.9 million non-D&C capital and $0.7 million non-operated D&C capital for 3Q2025. Excludes $18.8 million of discretionary capital, $6.2 million non-D&C capital and $2.2 million of non-operated D&C capital for YTD2025.
2. Includes LOE, GP&T and taxes other than income.
3. Adjusted EBITDA and adjusted free cash flow are non-GAAP financial measures; see supplemental slides. Adjusted free cash flow excludes discretionary acreage acquisitions and equity repurchases.
4. As of 9/30/2025 using net debt to LTM Adjusted EBITDA. Net debt and Adjusted EBITDA are non-GAAP measures. Net debt is defined as total long-term debt minus cash and cash equivalents.
5. Includes redemption of preferred equity totaling $31.3 million or ~180,000 shares of common stock on an as-converted basis based on redemption price of $174.22.

2025 Capital Program and Production Outlook

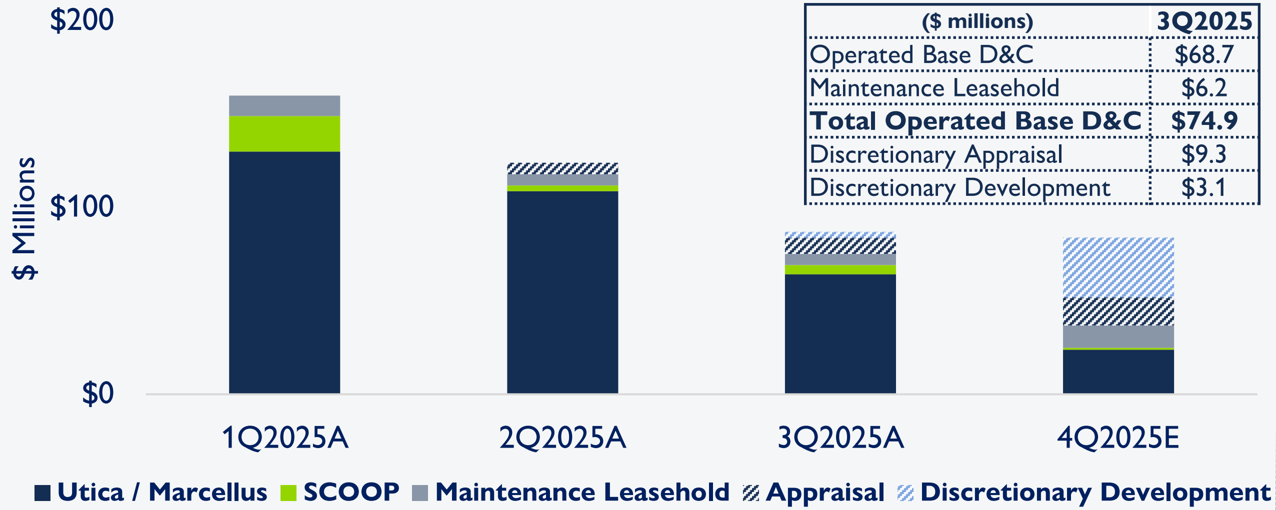
Capital Program

- Budgeting ~$390 million of total base capital expenditures
- Allocating ~$30 million toward discretionary appraisal projects, including DUC / recompletion activity and U-development
- Allocating ~$35 million toward discretionary development activity in 2H2025 to benefit the 2026 development program
- Investing ~$75 – $100 million in targeted discretionary acreage acquisitions by end of 1Q2026, expanding inventory runway by ~2 years[1]

Production

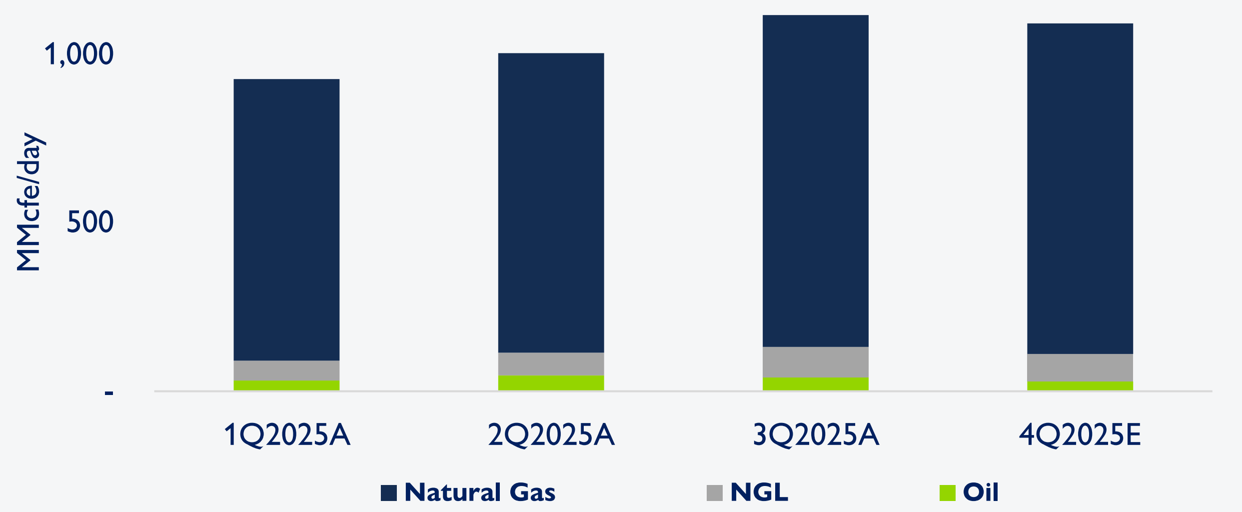
- Forecast full year total net daily production of ~1.04 Bcfe per day
- Net daily liquids production to be in the range of 18.0 to 20.5 MBbl/day
- Turned-to-sales 28 gross wells YTD2025 across all five of development areas (Utica condensate, Utica wet gas, Utica dry gas, Marcellus, SCOOP)
- Discretionary development activity anticipated to mitigate production impact from offset operator simultaneous operations and planned midstream maintenance downtime anticipated in early 2026

Total Capital Expenditures



($ millions)	3Q2025
Operated Base D&C	$68.7
Maintenance Leasehold	$6.2
Total Operated Base D&C	**$74.9**
Discretionary Appraisal	$9.3
Discretionary Development	$3.1

Total Net Production



1. Based on assumed development cadence of approximately 20 to 25 wells per year.

2025 Development Plan Overview

Utica Key Highlights

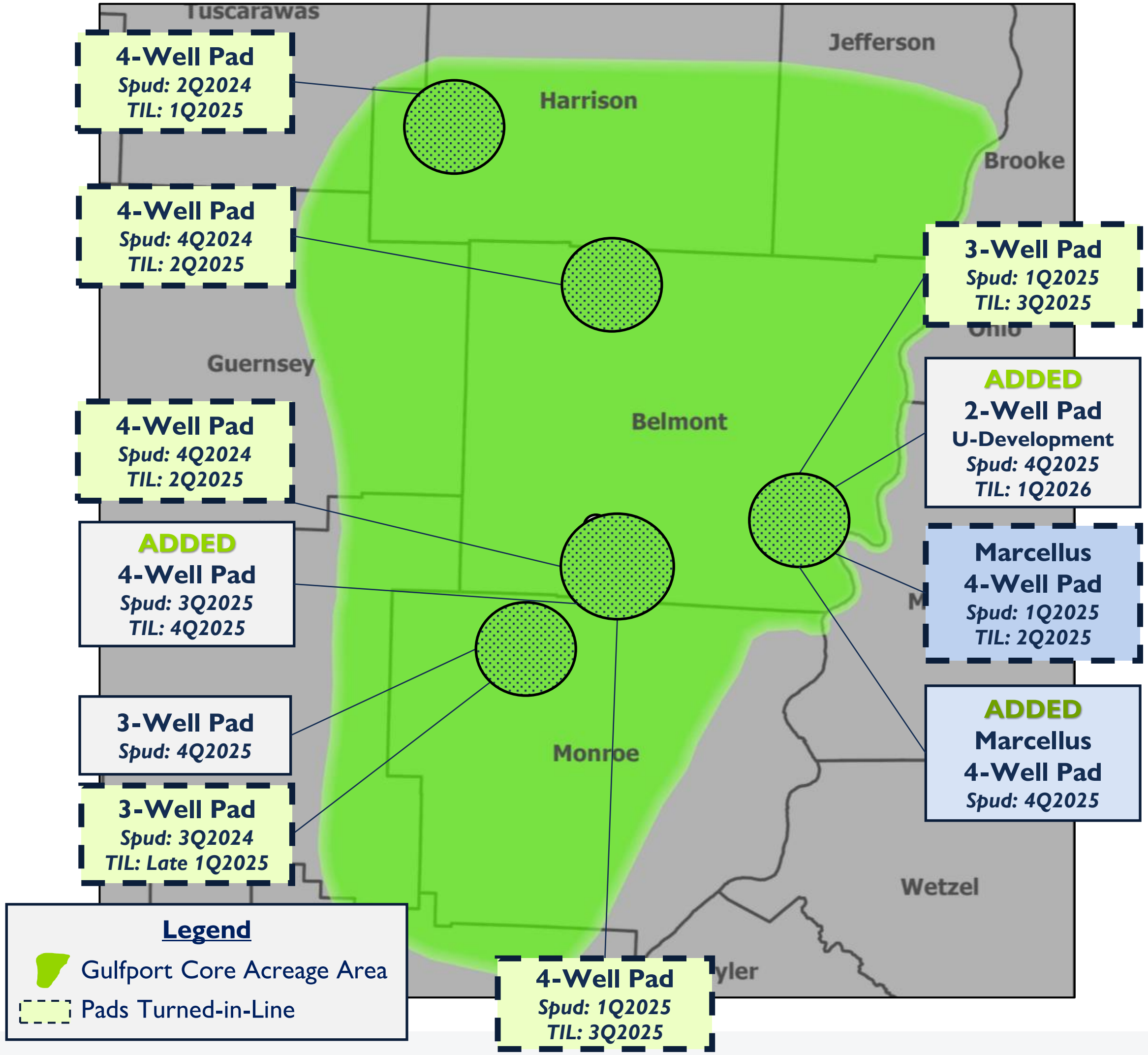
- Extended Utica inventory by >3.5 years[1] since year-end 2022
  - Discretionary acreage acquisitions added >2.5 years[1] since 2022, largely within the wet gas area of the play
  - Evaluation of U-development unlocked ~1 year[1] of dry gas inventory
- Adding incremental discretionary development activity 2H2025 to mitigate production impacts from offset operator simultaneous operations and planned midstream maintenance in early 2026
- Continue to optimize well performance and implement a managed pressure program, yielding consistent EUR's per well

Marcellus Key Highlights

- Marcellus development is within Utica footprint and captures value enhancement through stacked pay synergies and liquids optionality
  - Drilled and recently turned-to-sales 4 gross wells during 2Q2025
- Estimate 95 – 105 net locations, >4 years[1] of drillable inventory

SCOOP Key Highlights

- Targeting high return, liquids-rich development in the SCOOP
- Completed drilling and turned-to-sales 2 gross wells during 2025



1. Based on assumed development cadence of approximately 20 to 25 wells per year.

2025 Development Plan Overview

	2025 Operated Activity			2025E Operated Activity		
	PREVIOUS			UPDATED		
		Well Count	Lateral		Well Count	Lateral
Spud	Utica Dry Gas	14 gross (14.0 net)	16,900’	Utica Dry Gas	16 gross (16.0 net)	14,700’
	Utica Wet Gas	1 gross (1.0 net)	15,700’	Utica Wet Gas	1 gross (1.0 net)	15,700’
	Utica Condensate	-	-	Utica Condensate	-	-
	Marcellus	4 gross (4.0 net)	8,600’	Marcellus	8 gross (8.0 net)	12,300’
	SCOOP	-	-	SCOOP	-	-
Drilled	Utica Dry Gas	16 gross (15.9 net)	16,000’	Utica Dry Gas	19 gross (18.9 net)	14,600’
	Utica Wet Gas	4 gross (4.0 net)	17,300’	Utica Wet Gas	4 gross (4.0 net)	17,300’
	Utica Condensate	-	-	Utica Condensate	-	-
	Marcellus	4 gross (4.0 net)	8,600’	Marcellus	4 gross (4.0 net)	8,600’
	SCOOP	2 gross (1.8 net)	11,500’	SCOOP	2 gross (1.8 net)	11,500’
Completed	Utica Dry Gas	14 gross (14.0 net)	15,600’	Utica Dry Gas	20 gross (20.0 net)	15,200’
	Utica Wet Gas	4 gross (4.0 net)	17,300’	Utica Wet Gas	4 gross (4.0 net)	17,300’
	Utica Condensate	4 gross (4.0 net)	12,100’	Utica Condensate	4 gross (4.0 net)	12,100’
	Marcellus	4 gross (4.0 net)	8,600’	Marcellus	4 gross (4.0 net)	8,600’
	SCOOP	2 gross (1.8 net)	11,500’	SCOOP	2 gross (1.8 net)	11,500’
Turned-to-Sales	Utica Dry Gas	14 gross (14.0 net)	15,600’	Utica Dry Gas	18 gross (18.0 net)	15,200’
	Utica Wet Gas	4 gross (4.0 net)	17,300’	Utica Wet Gas	4 gross (4.0 net)	17,300’
	Utica Condensate	4 gross (4.0 net)	12,100’	Utica Condensate	4 gross (4.0 net)	12,100’
	Marcellus	4 gross (4.0 net)	8,600’	Marcellus	4 gross (4.0 net)	8,600’
	SCOOP	2 gross (1.8 net)	11,500’	SCOOP	2 gross (1.8 net)	11,500’

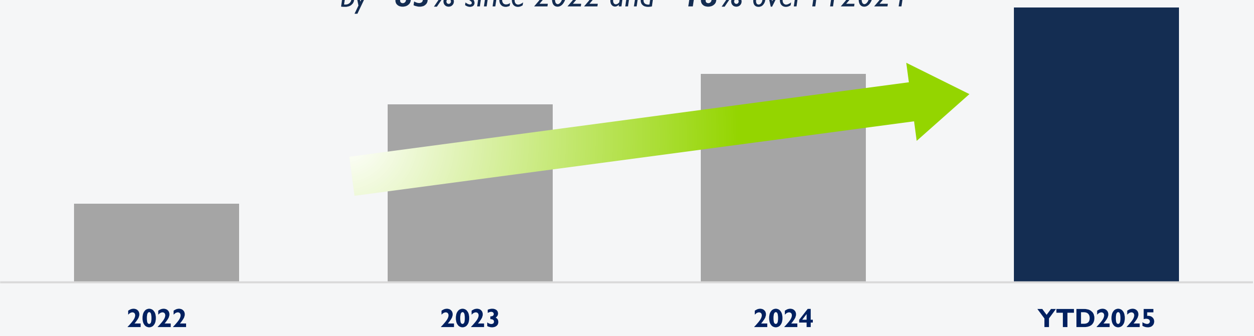
Note: Utica Wet Gas assumes oil yield of < 15 Bbl / MMcf.

Maintaining Best-in-Class Operational Efficiencies

Ohio Drilling and Completion Efficiencies

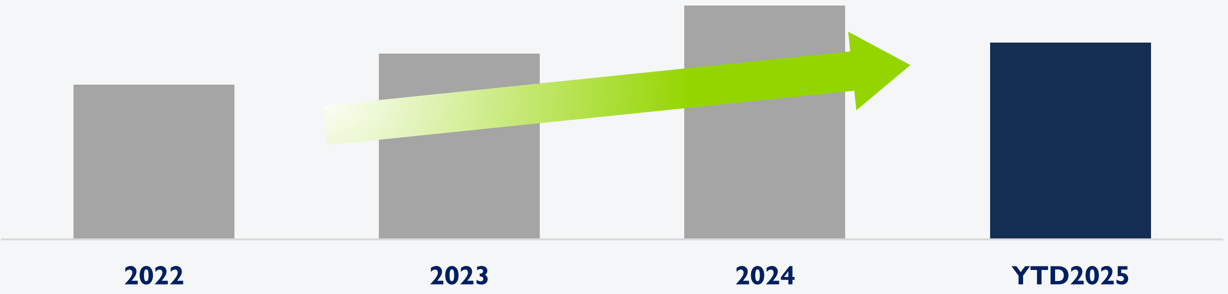
Average Total Footage per Day

Improved drilling efficiency
*by ~**83%** since 2022 and ~**18%** over FY2024*



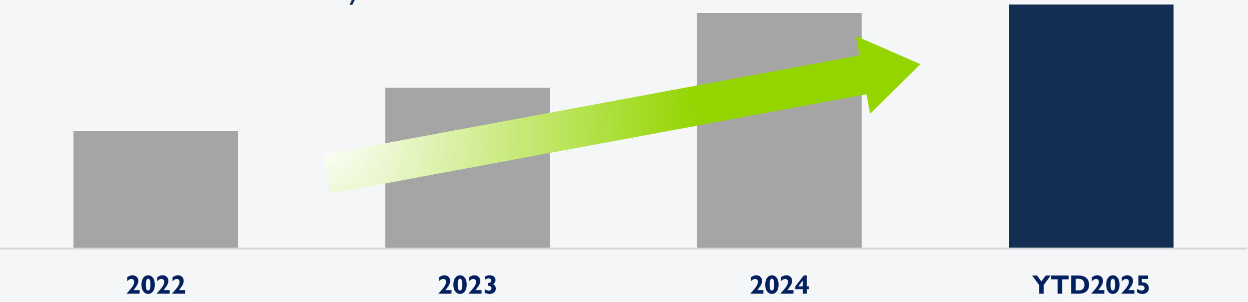
Average Frac Pumping Hours

Improved completion efficiency
*by ~**27%** since 2022 and maintaining top decile performance*



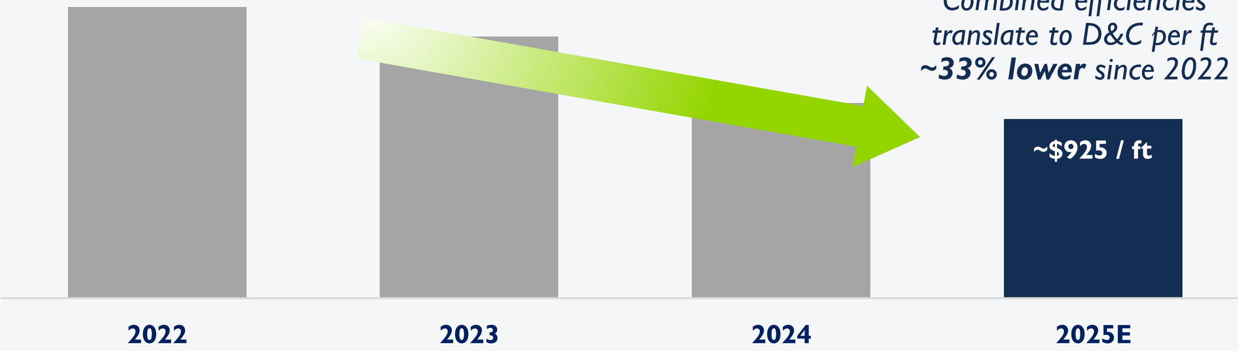
Average Plugs Drilled per Day

Improved drill out efficiency
*by ~**108%** since 2022 and ~**4%** over FY2024*



Utica D&C Cost Per Lateral Ft

Combined efficiencies
translate to D&C per ft
***~33% lower** since 2022*

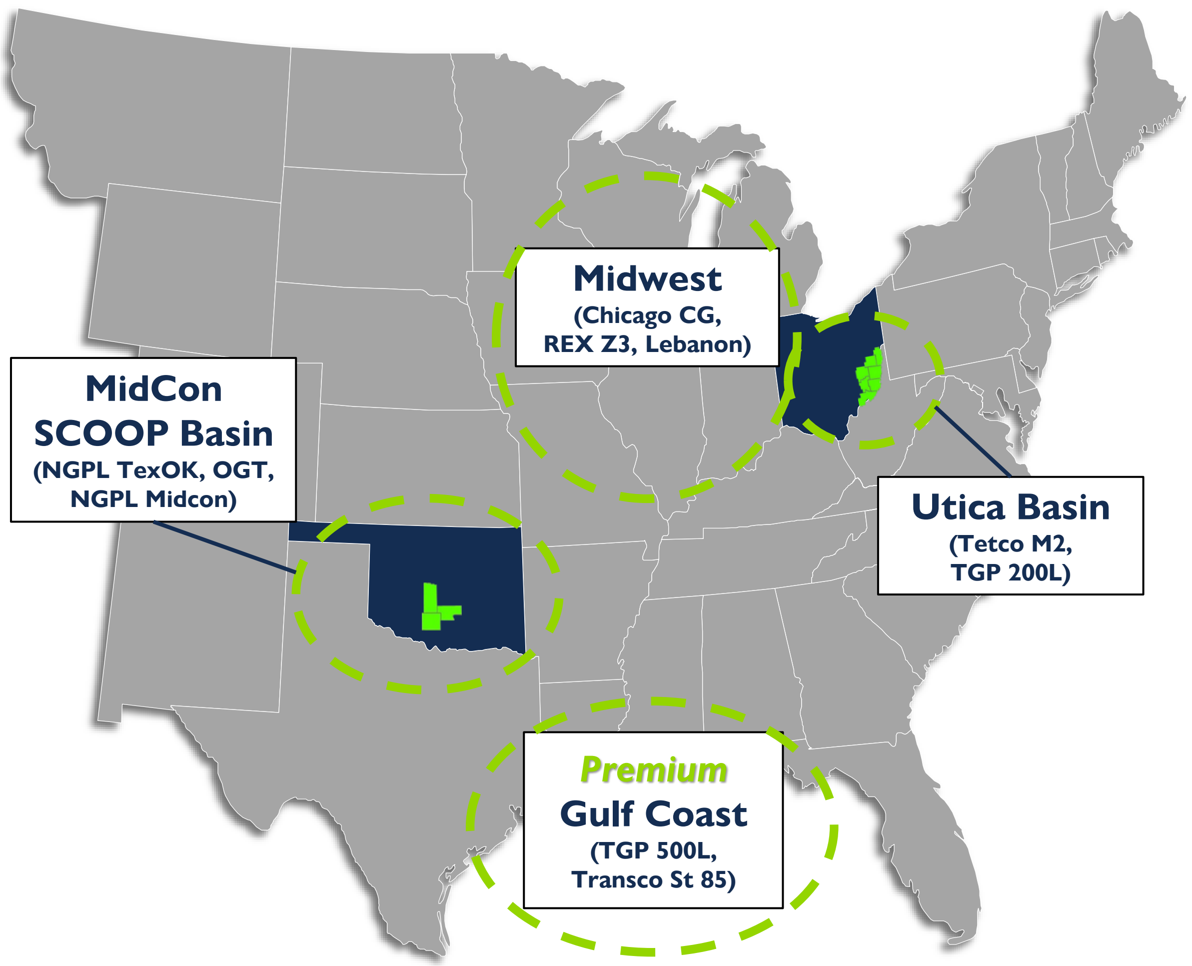


Gulfport ENERGY

Advantaged Firm Portfolio Provides Access to Diverse Markets

- Diversified and right-sized takeaway capacity
  - 625,000 MMBtu/d[1] of firm takeaway from the Utica
  - 200,000 MMBtu/d[1] of firm takeaway from the SCOOP
- Strategic connectivity to premium basin egress pipelines provides netback enhancement while maintaining exposure to in-basin demand growth opportunities
- Premium Gulf Coast transportation allows delivery to growing LNG demand center and industrial corridor at NYMEX-plus pricing
- Proactively hedge in-basin exposure to secure pricing

Regional Exposure[1]		2025E[2]
Midwest	450,000 MMBtu/d firm takeaway	30% - 40%
Gulf Coast	175,000 MMBtu/d firm takeaway	10% - 15%
MidCon	200,000 MMBtu/d firm takeaway	15% - 20%
In-Basin Exposure		30% – 40%



1. Primary reservation volume only. Excludes zero-leg and secondary-leg reservation volume. Assumes run-rate gross reservation volume on a MMBtu/d basis.
2. Percentages represent approximate gross production exposure to basin regions.

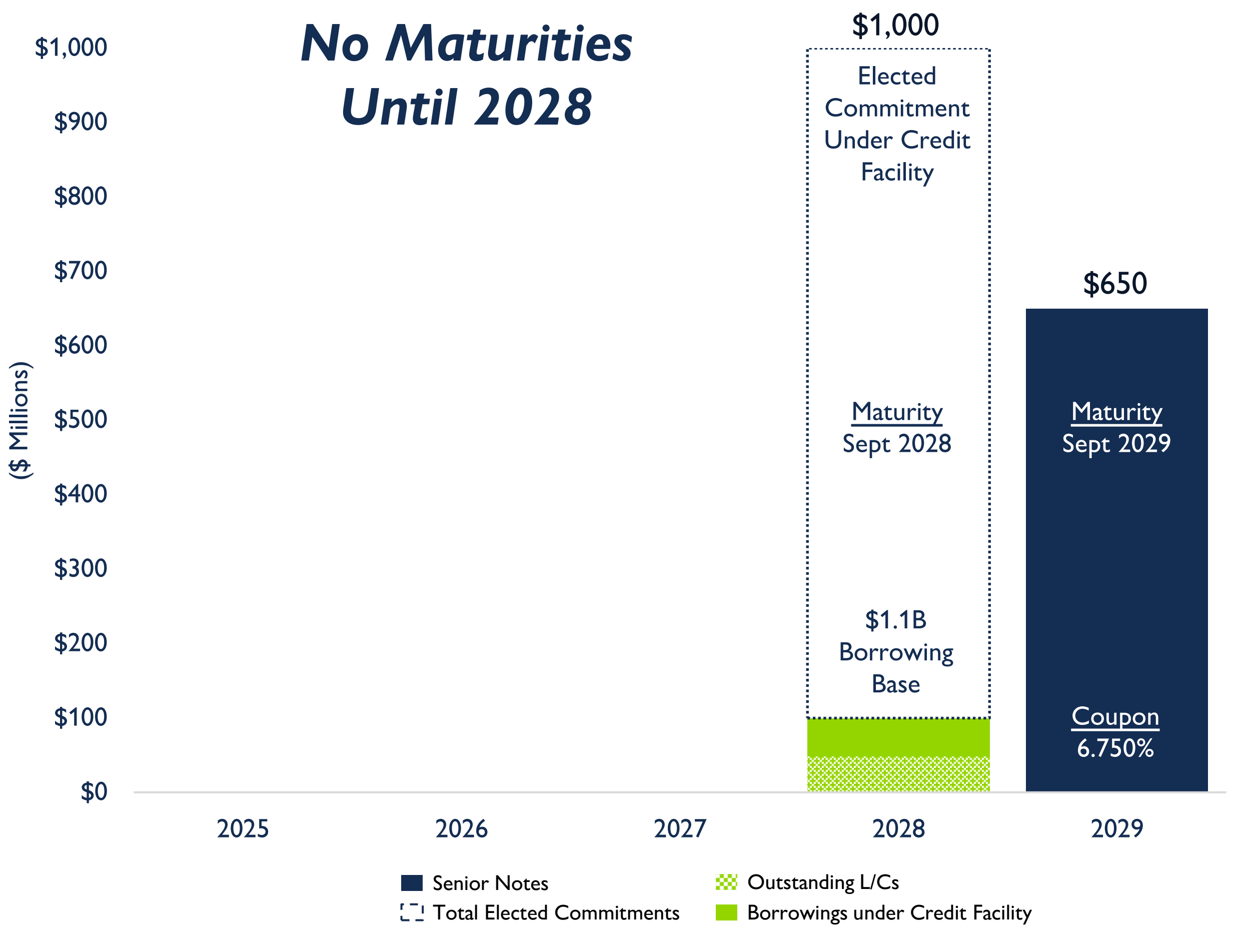
Strong Capital Structure and Financial Profile

Third Quarter 2025 Overview

Cash and Liquidity	• $3.4 million of cash equivalents • ~$903 million of liquidity(1)
Debt	• $51.0 million borrowings under credit facility • $650 million of senior notes due 2029 • Leverage of ~0.81x(2)

Equity	• Redeemed 2,449 shares of preferred stock for ~$31.3 million on September 5, 2025
	  • Prior to redemption date, 28,907 shares of preferred stock were converted into ~2.1 million shares of common stock
	  • No shares of preferred stock remain outstanding
	• Common stock: 19.5 million shares
	• Equity repurchase program authorized for up to $1.5 billion
	  • Repurchased ~$785.3 million as of September 30, 2025

As of September 30, 2025



1. Liquidity as of 9/30/25 and calculated as $3.4 million cash plus $900.3 million borrowing base availability, which takes into effect $51.0 million of borrowings on revolver and $48.7 million of letters of credit.
2. As of 9/30/2025 using net debt to TTM Adjusted EBITDA. Net debt is a non-GAAP measure. It is defined as total long-term debt minus cash and cash equivalents.

Focused on Continuous Improvement and Responsible Stewardship

Environmental

- **Achieved overall "A" rating for Appalachia assets from MiQ for third consecutive year**
- Applied key learnings from Appalachia, such as comprehensive leak detection program, elimination of natural gas-driven pneumatic devices and advanced methane detection and monitoring technologies, to Mid-Continent assets
- Continued to lower Scope 1 methane intensity(1), improving by 20% year-over-year and 33% since 2022
- Conducted climate risk assessment and integrated climate-related risk into Enterprise Risk Management (ERM) program

For additional information please refer to Gulfport's Corporate Sustainability Report

www.gulfportenergy.com/sustainability

Improved Methane Intensity Rate

↓ 33%(1) since 2022

Reduced Combined Total Recordable Incident Rate

↓ 54% since 2022

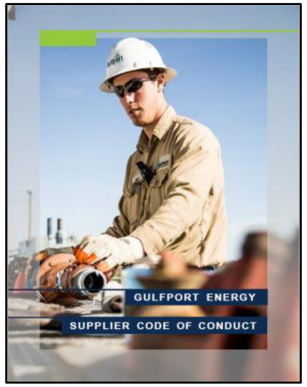
Social

- Reduced combined total recordable incident rate by 44% year-over-year, exceeding Company wide targets and recording the strongest annual safety performance to date
- Partnered with organizations that support Gulfport's key focus areas: education, health and human services, environmental stewardship and military and veterans
- Paid over $235 million in royalties to local landowners and working interest owners in 2024

Governance

- Experienced 7-member board including 6 independent directors
- 40% of directors identifying as gender or ethnically diverse
- Maintained separation of Chief Executive Officer and Chair roles while retaining Lead Independent Director
- Continued environmental, safety and governance short-term compensation incentive metrics with a 30% weighting

Vendor Code of Conduct can be found on Gulfport's website



Note: More details on our initiatives can be found on the Gulfport website: www.gulfportenergy.com

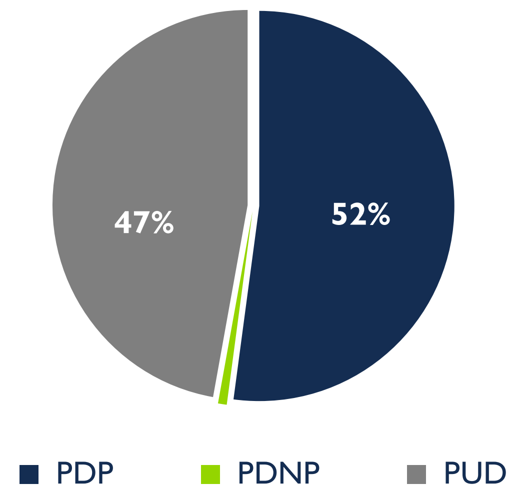
1. Reported full year 2024 and based on EPA required Subpart W reporting.

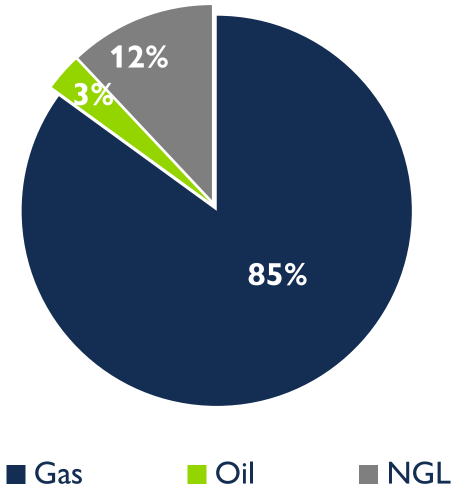
Appendix

2024 Proved Reserve Summary

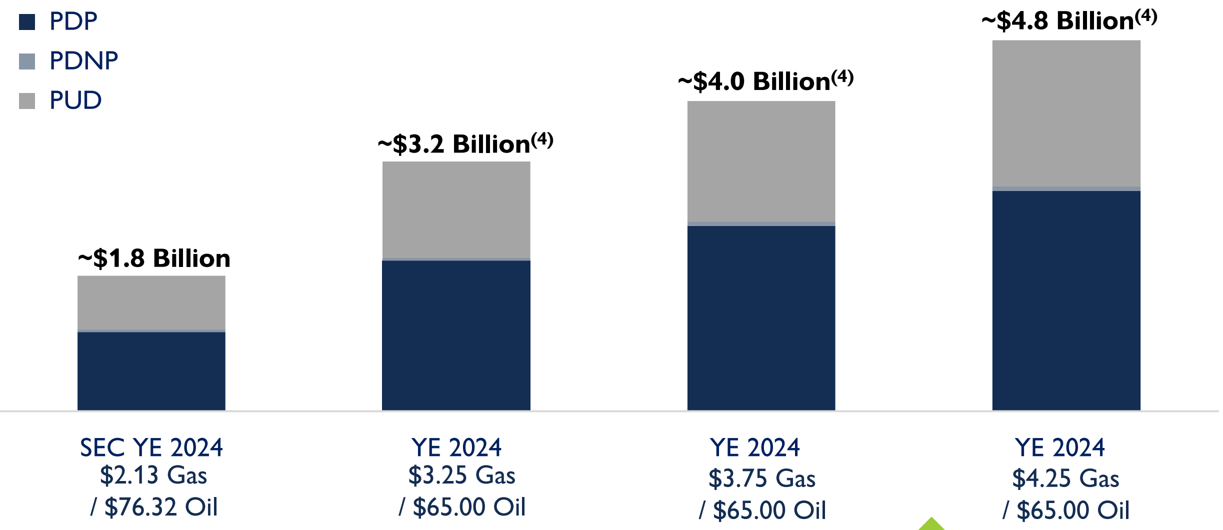
Net Reserves as of December 31, 2024[1]				
	Gas (Bcf)	Oil (MMBbls)	NGL (MMBbls)	Total (Bcfe)
Proved Developed Producing	1,844	7	29	2,061
Proved Developed Non-Producing	34	0	2	47
Proved Undeveloped[2]	1,478	15	49	1,861
Total Proved Reserves	3,356	22	80	3,969

Proved Reserve Components





SEC Year End Proved Reserves PV-10[3,4]



1. Per Company reserve report for year ending 12/31/24.
2. Proved undeveloped reserves, under SEC reserve reporting guidelines, only includes wells scheduled to be drilled within the next five years.
3. PV-10 is a non-GAAP measure; see supplemental slides.
4. Flat price cases at stated price scenarios.

Updated Full Year 2025 Guidance

	FY 2025E	
Production	**Guidance**	
Net Daily Gas Equivalent – MMcfe/day	~1,040	
Net Daily Liquids Production – MBbls/day	18.0	20.5
% Gas	~89%	
Realizations (before hedges)[1]		
Natural Gas (Differential to NYMEX) - $/Mcf	($0.20)	($0.35)
NGL (% of WTI)	40%	50%
Oil (Differential to NYMEX WTI) - $/Bbl	($5.50)	($6.50)
Expenses		
Lease Operating Expense - $/Mcfe	$0.19	$0.22
Taxes Other Than Income - $/Mcfe	$0.08	$0.10
GPT&C - $/Mcfe	$0.93	$0.97
Recurring Cash G&A[2] - $/Mcfe	$0.12	$0.14

	FY 2025E
Incurred Capital Expenditures – $ millions	**Guidance**
Operated Base D&C Capital Expenditures	~$355
Maintenance Land and Leasehold	~$35
Total Base Capital Expenditures	~$390
Discretionary Appraisal Capital	*~$30*
Discretionary Development Capital	*~$35*

2025E Adjusted Free Cash Flow Generation

- Allocating $75 million - $100 million to discretionary acreage acquisitions, expanding the Company's high-quality inventory by more than 2 years[3]
- Expect to repurchase ~$325 million of Gulfport's outstanding equity during 2025, inclusive of ~$125 million planned during 4Q2025, funded by adjusted free cash flow[4] and available capacity on our revolving credit facility while maintaining financial leverage at or below one times

Note: Guidance for the year ending 12/31/25 is based on multiple assumptions and certain analyses made by the Company based on its experience and perception of historical trends and current conditions and may change due to future developments. Actual results may not conform to the Company's expectations and predictions. Please refer to page 2 for more detail of forward-looking statements.

1. Based upon current forward pricing at October 14, 2025 and basis marks.
2. Recurring cash G&A is a non-GAAP financial measures; see supplemental slides.
3. Based on assumed development cadence of approximately 20 to 25 wells per year.
4. Adjusted free cash flow is a non-GAAP financial measures; see supplemental slides. Excludes discretionary acreage acquisitions and common stock repurchases.

Hedged Production

Natural Gas, Oil and Propane Hedge Summary[1]

	Natural Gas							Oil		Propane	
	Swaps		Collars			Calls Sold		Swaps		Swaps	
	Volume MMBtu/d	Avg. Price $/MMBtu	Volume MMBtu/d	Avg. Put $/MMBtu	Avg. Call $/MMBtu	Volume MMBtu/d	Avg. Call $/MMBtu	Volume Bbl/d	Avg. Price $/Bbl	Volume Bbl/d	Avg. Price $/Bbl
4Q 2025	270,000	$3.82	240,000	$3.42	$4.27	173,478	$5.93	3,000	$73.29	3,000	$29.89
Bal 2025[2]	270,000	$3.82	240,000	$3.42	$4.27	173,478	$5.93	3,000	$73.29	3,000	$29.89
1Q 2026	310,000	$3.80	150,000	$3.61	$4.35	-	-	-	-	3,000	$30.67
2Q 2026	310,000	$3.80	150,000	$3.61	$4.35	-	-	-	-	3,000	$30.67
3Q 2026	310,000	$3.80	150,000	$3.61	$4.35	-	-	-	-	2,000	$31.25
4Q 2026	310,000	$3.80	150,000	$3.61	$4.35	-	-	-	-	2,000	$31.25
FY 2026	310,000	$3.80	150,000	$3.61	$4.35	-	-	-	-	2,496	$30.91
1Q 2027	130,000	$3.94	110,000	$3.75	$4.27	-	-	-	-	-	-
2Q 2027	130,000	$3.94	110,000	$3.75	$4.27	-	-	-	-	-	-
3Q 2027	130,000	$3.94	110,000	$3.75	$4.27	-	-	-	-	-	-
4Q 2027	130,000	$3.94	110,000	$3.75	$4.27	-	-	-	-	-	-
FY 2027	130,000	$3.94	110,000	$3.75	$4.27	-	-	-	-	-	-

Basis Hedge Summary[1]

	Tetco M2 Basis		Rex Zone 3 Basis		NGPL TXOK Basis		TGP 500 Basis		Transco Station 85 Basis	
	Swaps		Swaps		Swaps		Swaps		Swaps	
	Volume MMBtu/d	Avg. Price $/MMBtu	Volume MMBtu/d	Avg. Price $/MMBtu	Volume MMBtu/d	Avg. Price $/MMBtu	Volume MMBtu/d	Avg. Price $/MMBtu	Volume MMBtu/d	Avg. Price $/MMBtu
4Q 2025	230,000	($0.96)	110,000	($0.20)	40,000	($0.29)	20,000	$0.41	10,000	$0.45
Bal 2025[2]	230,000	($0.96)	110,000	($0.20)	40,000	($0.29)	20,000	$0.41	10,000	$0.45
1Q 2026	170,000	($0.95)	80,000	($0.18)	30,000	($0.30)	20,000	$0.56	10,000	$0.56
2Q 2026	170,000	($0.95)	80,000	($0.18)	30,000	($0.30)	20,000	$0.56	10,000	$0.56
3Q 2026	170,000	($0.95)	80,000	($0.18)	30,000	($0.30)	20,000	$0.56	10,000	$0.56
4Q 2026	170,000	($0.95)	80,000	($0.18)	30,000	($0.30)	20,000	$0.56	10,000	$0.56
FY 2026	170,000	($0.95)	80,000	($0.18)	30,000	($0.30)	20,000	$0.56	10,000	$0.56
1Q 2027	40,000	($0.93)	-	-	10,000	($0.29)	-	-	-	-
2Q 2027	40,000	($0.93)	-	-	10,000	($0.29)	-	-	-	-
3Q 2027	40,000	($0.93)	-	-	10,000	($0.29)	-	-	-	-
4Q 2027	40,000	($0.93)	-	-	10,000	($0.29)	-	-	-	-
FY 2027	40,000	($0.93)	-	-	10,000	($0.29)	-	-	-	-

1. As of 10/29/25.
2. October 2025 – December 2025.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure equal to net income (loss), the most directly comparable GAAP financial measure, plus interest expense, income tax expense (benefit), depreciation, depletion and amortization, impairment and accretion, net non-cash derivative loss (gain), non-recurring general and administrative expenses comprised of expenses related to the continued administration of our prior Chapter 11 filing, stock-based compensation, loss on debt extinguishment and other items which include non-material expenses.

Below is a reconciliation of net income (loss) (a GAAP measure) to Adjusted EBITDA. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

(In thousands)
(Unaudited)

	Three Months Ended September 30, 2025	Three Months Ended September 30, 2024	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024
Net income (loss) (GAAP)	$ 111,393	$ (13,967)	$ 295,395	$ 11,856
Adjustments:				
Interest expense	13,590	15,866	40,677	46,027
Income tax expense (benefit)	31,410	(3,833)	82,904	3,433
DD&A, impairment and accretion	83,813	113,895	224,283	273,593
Non-cash derivative (gain) loss	(33,052)	46,911	(13,055)	166,454
Non-recurring general and administrative expenses	407	33	1,438	1,561
Stock-based compensation expenses	2,942	2,664	9,245	8,410
Loss on debt extinguishment	—	13,388	—	13,388
Other, net	2,596	3,133	2,795	3,530
Adjusted EBITDA (Non-GAAP)	$ 213,099	$ 178,090	$ 643,682	$ 528,252

Adjusted Free Cash Flow

Adjusted free cash flow is a non-GAAP measure defined as adjusted EBITDA plus certain non-cash items that are included in net cash provided by (used in) operating activities but excluded from adjusted EBITDA less interest expense, current income tax expense (benefit), capitalized expenses incurred and capital expenditures incurred, excluding discretionary acreage acquisitions. Gulfport includes ranges of expectations for adjusted free cash flow for 2025. We are unable, however, to provide a quantitative reconciliation of the forward-looking non-GAAP measure to its most directly comparable forward-looking GAAP measure because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. Accordingly, Gulfport is relying on the exception provided by Item 10(e)(1)(i)(B) of Regulation S-K to exclude such reconciliation. Items excluded in net cash provided by operating activities to arrive at adjusted free cash flow include interest expense, income taxes, capitalized expenses as well as one-time items or items whose timing or amount cannot be reasonably estimated.

Below is a reconciliation of net cash provided by operating activities (the most comparable GAAP measure) to free cash flow. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

(In thousands) (Unaudited)	Three Months Ended September 30, 2025	Three Months Ended September 30, 2024	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024
Net cash provided by operating activity (GAAP)	$ 209,078	$ 189,698	$ 617,761	$ 501,185
Adjustments:				
Interest expense	13,590	15,866	40,677	46,027
Non-recurring general and administrative expenses	407	33	1,438	1,561
Current income tax expense	(105)	—	—	—
Other, net	807	2,231	(1,639)	726
Changes in operating assets and liabilities, net				
Accounts receivable - oil, natural gas, and natural gas liquids sales	(6,624)	(5,415)	(33,952)	(33,548)
Accounts receivable - joint interest and other	(3,838)	(6,936)	(817)	(7,947)
Accounts payable and accrued liabilities	283	(15,900)	17,612	21,117
Prepaid expenses	(457)	(1,499)	2,603	(850)
Other assets	(42)	12	(1)	(19)
Total changes in operating assets and liabilities	$ (10,678)	$ (29,738)	$ (14,555)	$ (21,247)
Adjusted EBITDA (Non-GAAP)	$ 213,099	$ 178,090	$ 643,682	$ 528,252
Interest expense	(13,590)	(15,866)	(40,677)	(46,027)
Current income tax expense	105	—	—	—
Capitalized expenses incurred[1]	(6,325)	(6,413)	(18,762)	(17,991)
Capital expenditures incurred, excluding discretionary acreage acquisitions[2,3,4]	(89,853)	(83,254)	(379,615)	(332,633)
Adjusted free cash flow (Non-GAAP)	$ 103,436	$ 72,557	$ 204,628	$ 131,601

1. Includes cash capitalized general and administrative expense and incurred capitalized interest expenses.
2. Incurred capital expenditures and cash capital expenditures may vary from period to period due to the cash payment cycle.
3. For the three months ended September 30, 2025, includes $1.9 million and $0.7 million of non-D&C capital and non-operated capital expenditures, respectively. For the nine months ended September 30, 2025, includes $6.2 million and $2.2 million of non-D&C capital and non-operated capital expenditures, respectively. Additionally, excludes targeted discretionary acreage acquisitions of $15.7 million.
4. For the three months ended September 30, 2024, includes $0.8 million and $0.8 million of non-D&C capital and non-operated capital expenditures, respectively. For the nine months ended September 30, 2024, includes $3.7 million and $2.4 million of non-D&C capital and non-operated capital expenditures, respectively. Additionally, excludes targeted discretionary acreage acquisitions of $38.8 million.

Recurring General and Administrative (G&A) Expense

Recurring general and administrative expense is a non-GAAP financial measure equal to general and administrative expense (GAAP) plus capitalized general and administrative expense, less non-recurring general and administrative expenses comprised of expenses related to the continued administration of our prior Chapter 11 filing. Gulfport includes a recurring cash general and administrative expense estimate for 2025. We are unable, however, to provide a quantitative reconciliation of the forward-looking non-GAAP measure to its most directly comparable forward-looking GAAP measure because management cannot reliably quantify certain of the necessary components of such forward-looking GAAP measure. Accordingly, Gulfport is relying on the exception provided by Item 10(e)(1)(i) (B) of Regulation S-K to exclude such reconciliation. Items excluded in general and administrative expense to arrive at recurring general and administrative expense include capitalized expenses as well as one-time items or items whose timing or amount cannot be reasonably estimated.

Below is a reconciliation of general and administrative expense (the most comparable GAAP measure) to recurring general and administrative expense. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

(In thousands)
(Unaudited)

	Three Months September 30, 2025			Three Months Ended September 30, 2024		
	Cash	Non-Cash	Total	Cash	Non-Cash	Total
General and administrative expense (GAAP)	$ 8,893	$ 2,942	$ 11,835	$ 7,815	$ 2,664	$ 10,479
Capitalized general and administrative expense	4,789	1,449	6,238	5,183	1,312	6,495
Non-recurring general and administrative expense	(407)	—	(407)	(33)	—	(33)
Recurring General and Administrative Expense (Non-GAAP)	$ 13,275	$ 4,391	$ 17,666	$ 12,965	$ 3,976	$ 16,941

(In thousands)
(Unaudited)

	Nine Months September 30, 2025			Nine Months Ended September 30, 2024		
	Cash	Non-Cash	Total	Cash	Non-Cash	Total
General and administrative expense (GAAP)	$ 22,517	$ 9,245	$ 31,762	$ 22,019	$ 8,410	$ 30,429
Capitalized general and administrative expense	14,350	4,554	18,904	14,388	4,142	18,530
Non-recurring general and administrative expense	(1,438)	—	(1,438)	(1,561)	—	(1,561)
Recurring General and Administrative Expense (Non-GAAP)	$ 35,429	$ 13,799	$ 49,228	$ 34,846	$ 12,552	$ 47,398

Present value of estimated future net revenue (PV-10)

PV – 10 is a non-GAAP measure derived from standardized measure of discounted future new cash flows (GAAP). Management uses PV-10, which is calculated without deducting estimated future income tax expenses, as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented below. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

(In thousands)
(Unaudited)

	December 31, 2024			December 31, 2023		
	Proved Developed	Proved Undeveloped	Total Proved	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net revenue	$1,620	$1,876	$3,496	$2,535	$2,235	$4,769
Present value of estimated future net revenue (PV-10)	$1,059	$699	$1,757	$1,590	$819	$2,409
Standardized measure			$1,747			$2,383

Note: Reserves as of December 31, 2024 utilized prices of $76.32/Bbl of oil, $31.30/Bbl for NGLs and $2.13/MMBtu of natural gas. Reserves as of December 31, 2023 utilized prices of $78.21/Bbl of oil, $31.42/Bbl for NGLs and $2.64/MMBtu of natural gas. Prices are determined in accordance with the SEC requirement to use the unweighted arithmetic average of the first day-of-the-month price for the preceding twelve months without giving effect to derivative transactions.

Gulfport ENERGY

Thank You.

Investor Relations
405.252.4550
investor_relations@gulfportenergy.com
www.gulfportenergy.com