2Q 2025 Earnings

JULY 29, 2025

Forward-Looking Statements

This presentation includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include our current expectations or forecasts of future events, including matters relating to armed conflict and instability in Europe and the Middle East, along with the effects of the current global economic environment, and the impact of each on our business, financial condition, results of operations and cash flows, actions by, or disputes among or between, members of OPEC+ and other foreign oil0exporting countries, market factors, market prices, our ability to meet debt service requirements, our ability to continue to pay cash dividends, our ability to capture synergies, the amount and timing of any cash dividends and our environmental, social and governance (“ESG”) initiatives. Forward-looking and other statements in this presentation regarding our environmental, social and other sustainability plans and goals are not an indication that these statements are necessarily material to investors or required to be disclosed in our filings with the Securities and Exchange Commission (“SEC”). In addition, historical, current, and forward-looking environmental, social and sustainability-related statements may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future. Forward-looking statements often address our expected future business, financial performance and financial condition, and often contain words such as “aim”, “predict”, “should”, “expect,” “could,” “may,” “anticipate,” “intend,” “plan,” “ability,” “believe,” “seek,” “see,” “will,” “would,” “estimate,” “forecast,” “target,” “guidance,” “outlook,” “opportunity” or “strategy.” The absence of such words or expressions does not necessarily mean the statements are not forward-looking.

Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time. Particular uncertainties that could cause our actual results to be materially different than those expressed in our forward-looking statements include:

- reduced demand for natural gas, oil, and natural gas liquids (“NGLs”);
- negative public perceptions of our industry;
- competition in the natural gas and oil exploration and production industry;
- the volatility of natural gas, oil and NGL prices, which are affected by general economic and business conditions, as well as increased demand for (and availability of) alternative fuels and electric vehicles;
- risks from regional epidemics or pandemics and related economic turmoil, including supply chain constraints;
- write-downs of our natural gas and oil asset carrying values due to low commodity prices;
- significant capital expenditures are required to replace our reserves and conduct our business;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- drilling and operating risks and resulting liabilities;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;
- risks from our commodity price risk management activities;
- uncertainties, risks and costs associated with natural gas and oil operations;
- our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- pipeline and gathering system capacity constraints and transportation interruptions;
- risks related to our plans to participate in the global LNG value chain;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- risks from failure to protect personal information and data and compliance with data privacy and security laws and regulations;
- disruption of our business by natural or human causes beyond our control;
- a deterioration in general economic, business or industry conditions;
- the impact of inflation and commodity price volatility, including as a result of decisions made by OPEC+ and armed conflict and instability in Europe and the Middle East, along with the effects of the current global economic environment, on our business, financial condition, employees, contractors, vendors and the global demand for natural gas and oil and on U.S. and global financial markets;
- our inability to access the capital markets on favorable terms;
- the limitations on our financial flexibility due to our level of indebtedness and restrictive covenants from our indebtedness;
- challenges with employee retention and increasingly competitive labor market;
- risks related to acquisitions or dispositions, or potential acquisitions or dispositions;
- security threats, including cybersecurity threats and disruptions to our business and operations from breaches of our information technology systems, or from breaches of information technology systems of third parties with whom we transact business;
- our ability to achieve and maintain ESG certifications, goals and commitments;
- legislative, regulatory and ESG initiatives, including those addressing the impact of climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal;
- federal and state tax proposals affecting our industry;
- risks related to an annual limitation on the utilization of our tax attributes, which was triggered upon the completion of our merger with Southwestern Energy Company (the “Southwestern Merger”), as well as trading in our common stock, additional issuance of common stock, and certain other stock transactions, which could lead to an additional, potentially more restrictive, annual limitation; and
- other factors that are described under RISK Factors in Item 1A of Part I of our Annual Report on Form 10-K filed with the SEC.

This presentation references non-GAAP financial measures and metrics, including certain forward-looking information regarding such measures that are not reconcilable with GAAP measures due to their inherent uncertainty. Please see Appendix, which includes definitions of non-GAAP measures and metrics used in this presentation and reconciliations of non-GAAP measures to the most directly comparable GAAP measure.

We caution you not to place undue reliance on the forward-looking statements contained in this presentation, which speak only as of the filing date, and we undertake no obligation and have no intention to update any forward-looking statement, except as required by law. We urge you to carefully review and consider the disclosures in this presentation and our filings with the SEC that attempt to advise interested parties of the risks and factors that may affect our business.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

2Q25 Operational and Financial Highlights

Largest Domestic Natural Gas Producer: ~7.2 Bcfe/d

2Q25 beat with:
~$1.2bn of adj. EBITDAX(1)
~$727mm of capex

~$425mm of Incremental FCF Uplift in 2025

Improved guidance for G&A, LOE, capex and taxes

Annual Synergy Outlook Increased to $600mm(2)

Size, scale and timing of previously disclosed efficiency gains continue to improve

Increasing 2025 Net Debt Paydown to $1.0bn

Multi-year deleveraging effort to improve full-cycle balance sheet capacity

Returning $585mm to shareholders in the form of dividends and share repurchases in 1H25

Released Inaugural EXE Sustainability Report

Builds on the strong foundation of transparent reporting established by our legacy companies

Fastest Drilling Quarter in Company History

Delivered highest average drilled footage per day across all three business units during 2Q25

(1) Adjusted EBITDAX is a non-GAAP financial measure, see Appendix for more information and a reconciliation to the most directly comparable GAAP financial measure
(2) Expected by YE26

Attractive, Connected Portfolio

Northeast Appalachia

~700,000 net acres

>1,500 gross locations

FY25E Prod: ~2,625 MMcfe/d

Southwest Appalachia

~566,000 net acres

>1,500 gross locations

FY25E Prod: ~1,550 MMcfe/d

Haynesville

~664,000 net acres

>2,000 gross locations

FY25E Prod: ~2,925 MMcfe/d

Superior Portfolio Characteristics

Scale: Largest natural gas producer in North America with ~1.9mm net acres, ~7.1 Bcfe/d in 2025

Flexibility: Highly complementary asset base offers capital allocation flexibility

Growth: Differentiated ability to accretively grow volumes (when supply is needed)

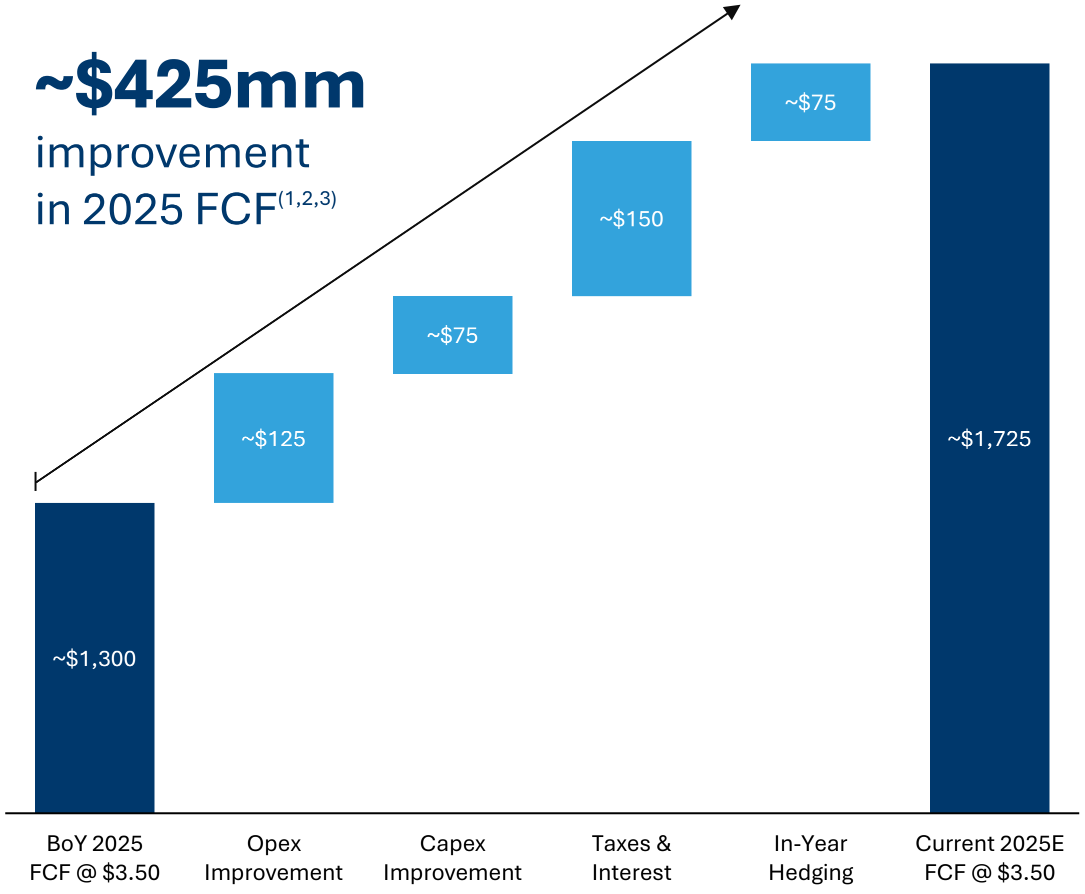
Location: Unique access to premium markets and highest value demand centers

Longevity: Deep inventory supporting returns for decades (20+ years[1])

(1) >5,000 gross locations divided by ~250 annual TILs

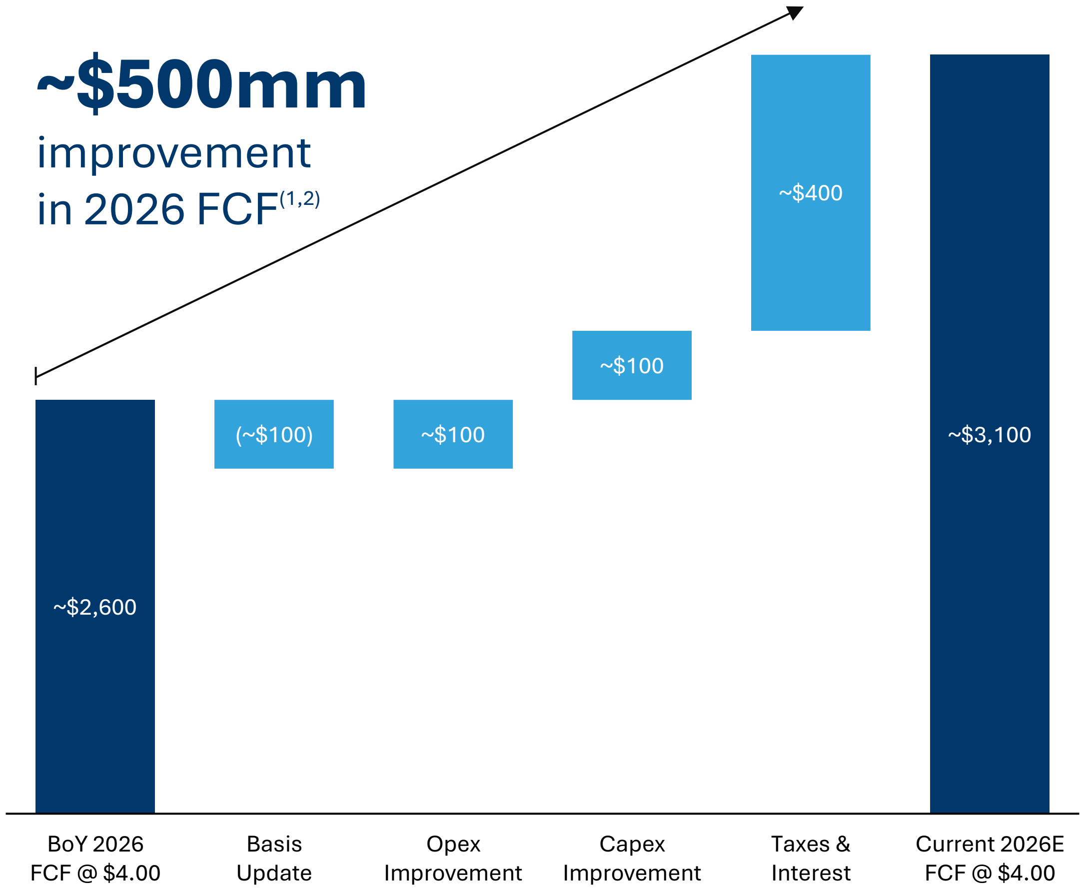
Significant Improvement to FCF

~$425mm improvement in 2025 FCF[1,2,3]



2025 (~7.1 Bcfe/d)

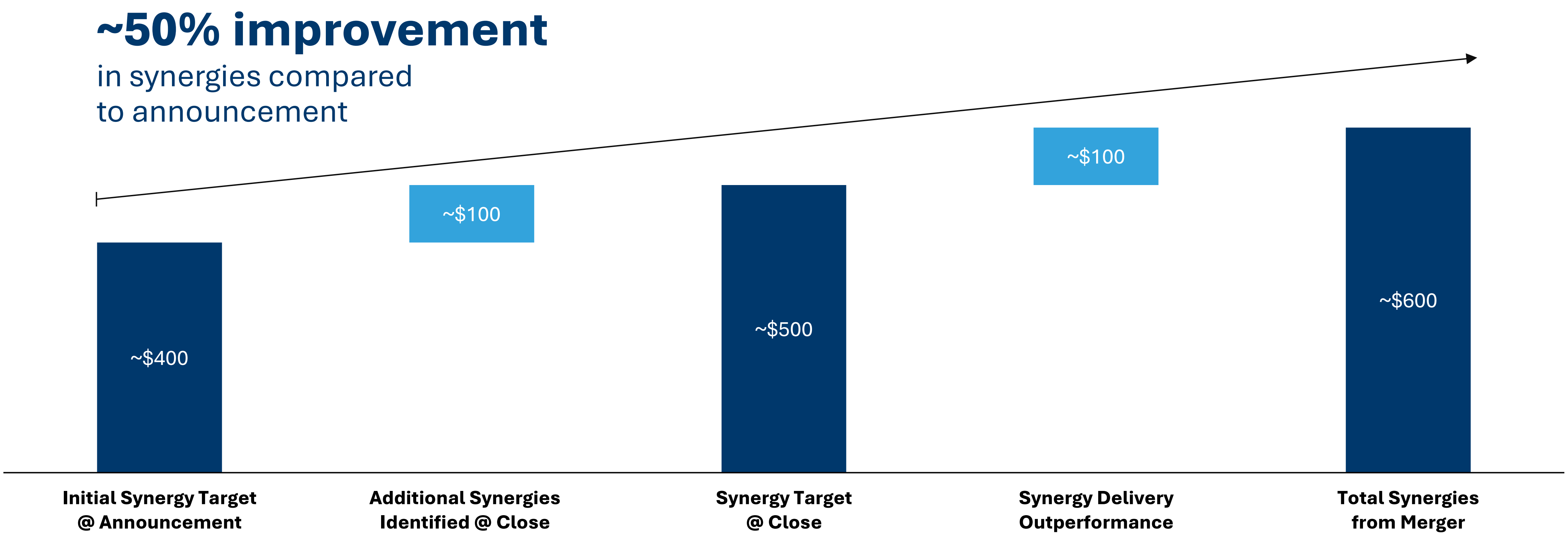
~$500mm improvement in 2026 FCF[1,2]



2026 (~7.5 Bcfe/d)

(1) FCF is a non-GAAP financial measure, see Appendix for more information
(2) Axis not to scale; BoY 2025 / 2026 FCF estimates from 4Q24 earnings presentation 2/26/2025; 2025 and 2026 FCF include expected synergy capture and exclude working capital adjustments; Assumes $70/bbl WTI and 40% NGL
(3) In-year hedging is calculated as the gain from hedges added since 2/19/2025, assuming $3.50/mcf

Merger Synergies Continue to Exceed Expectations



Initial Synergy Target @ Announcement

- Corporate and regional costs
- D&C cost savings
- Other operating and capital
- ~$250mm by 2025 and $400mm by 2026

Additional Synergies Identified @ Close

- Haynesville sand mine cost savings
- Completion design optimization
- Financing cost savings

Synergy Target @ Close

- Accelerated to ~$400mm in 2025 and ~$500mm in 2026

Synergy Delivery Outperformance

- Continued optimization of Haynesville drilling program
- Incremental non-comp G&A realization around IT spend
- Increased Haynesville sand mine utilization
- Optimization of Haynesville facility design

Total Synergies from Merger

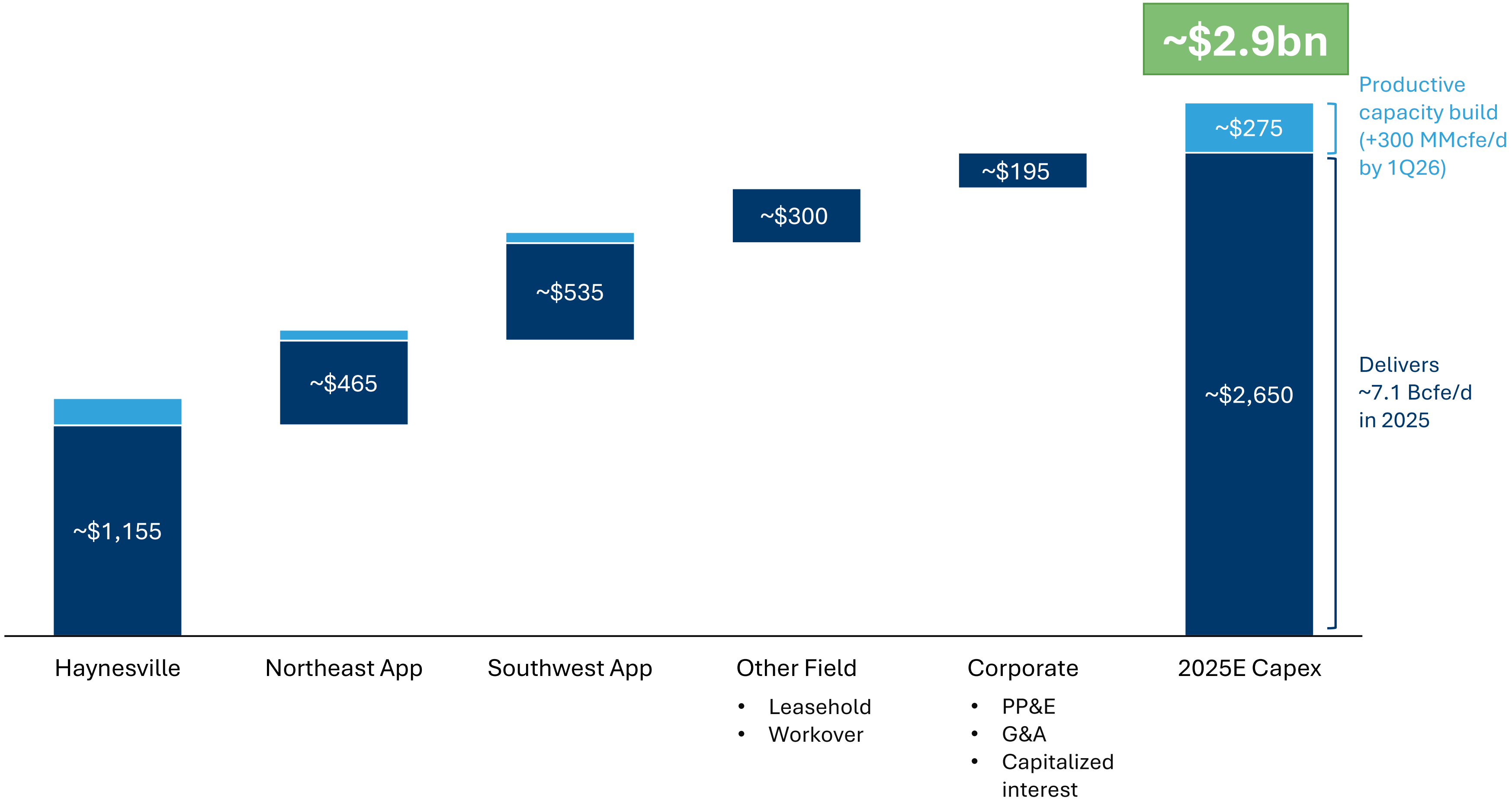
- Accelerated to ~$500mm in 2025 and ~$600mm in 2026

Improved 2025 Capital Outlook

- Reduced FY25 D&C capex spend by ~$100mm
- Record drilling performance driving capital efficiencies
- ~300 MMcfe/d of available productive capacity by 2026

2025 Capital Expenditures

(Implied Midpoints of 2025 Guidance, $mm)

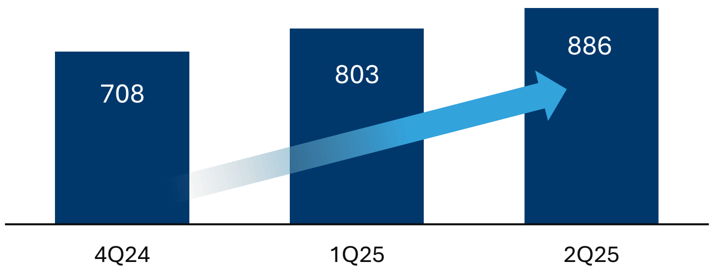


Record Drilling Performance

Haynesville

- Delivered record quarterly footage/day (FPD) during 2Q25
- Drilled 6 of top 10 best FPD wells in 1H25
- Drilled longest EXE Haynesville lateral to date at 16,133'
- Delivered first sub 3-day rig move

Haynesville
(Avg. Footage per Day)

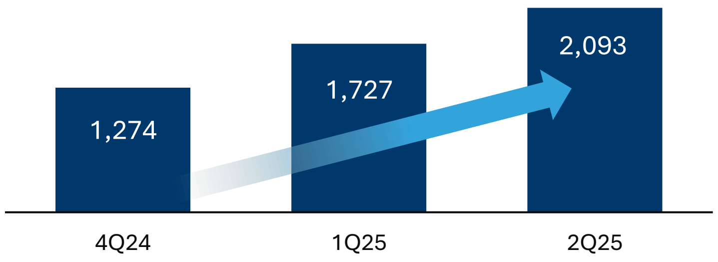


+1 well/rig/yr vs. original guidance[1]

Northeast Appalachia

- Delivered record quarterly FPD during 2Q25
- Drilled 4 of top 10 best FPD wells in 1H25
- Drilled 9 of top 10 best FPD wells since beginning of 2024

NE App
(Avg. Footage per Day)

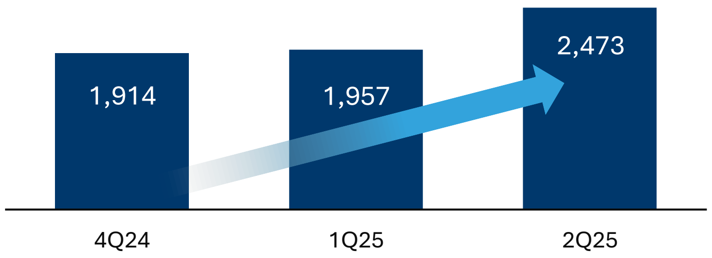


+4 wells/rig/yr vs. original guidance[1]

Southwest Appalachia

- Delivered record quarterly FPD during 2Q25
- U.S. land bit run record: 30,368' measured depth drilled on a single bit in <5 days
- U.S. land lateral length record: 27,657'
- New Marcellus (2,867') and Utica (1,710') FPD records

SW App[2]
(Avg. Footage per Day)



+4 wells/rig/yr vs. original guidance[1]

(1) Modeling assumptions slide 35 in 4Q & FY24 Earnings deck
(2) Marcellus formation wells

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AI and Machine Learning Supports Record Performance

- Rapid integration of telemetry data across the rig fleet has enhanced operational learnings

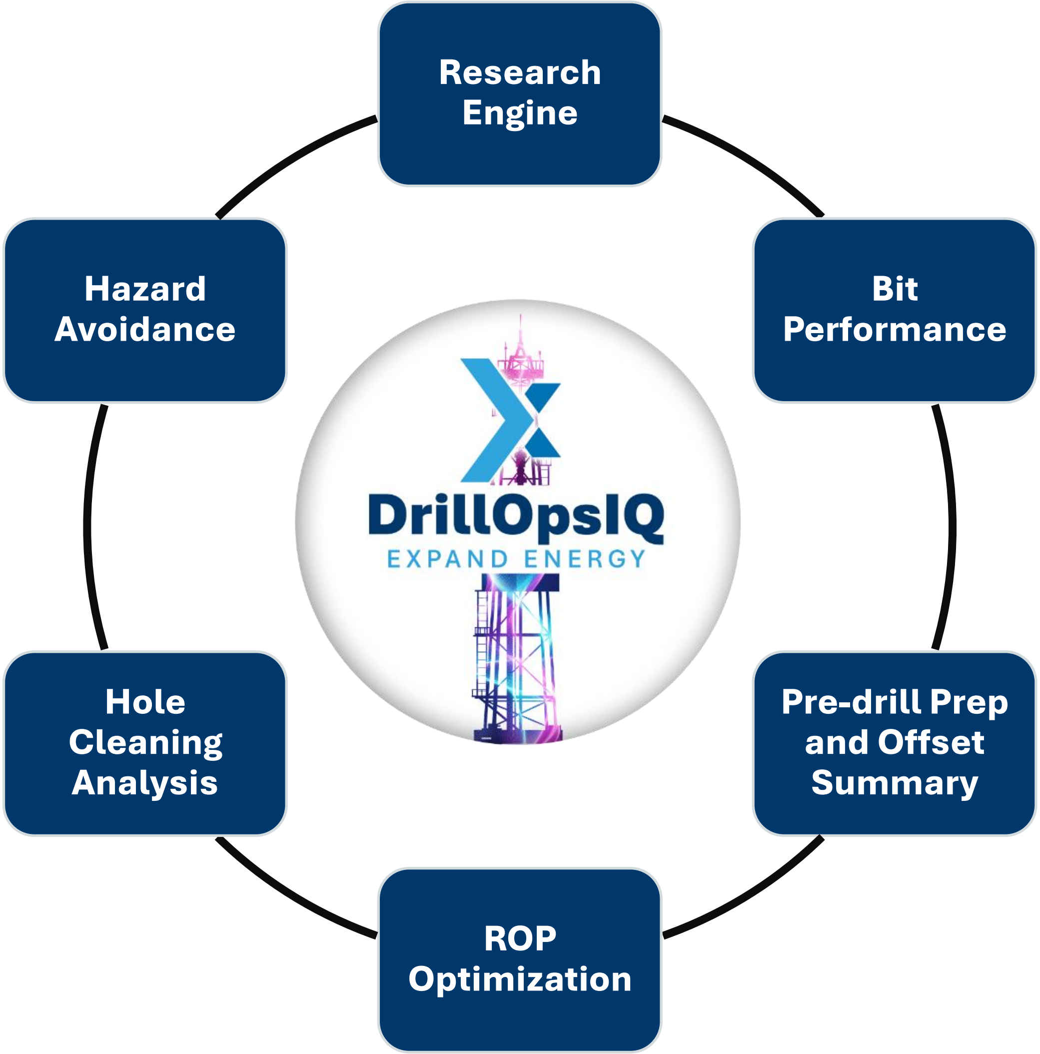
- Optimizing drilling operations through proprietary machine learning models built in-house

  - ***DrillOpsIQ* Platform:** Enables agentic optimization for real-time insights, predictive analytics and intelligent drilling

  - ***SEER*[1] Tool:** Monitors BHA[2] diagnostics, including temperature, drilling time and footage, to feed custom-built predictive models for motor failure detection

  - ***Build and Turn* Tool:** Analyzes BHA tendencies in real-time to aid in slide versus rotate parameters

- Improved insight and faster decision-making is helping achieve drilling records across portfolio



(1) Internal acronym reflecting System for Evaluating Equipment Risk
(2) Bottom-hole assembly

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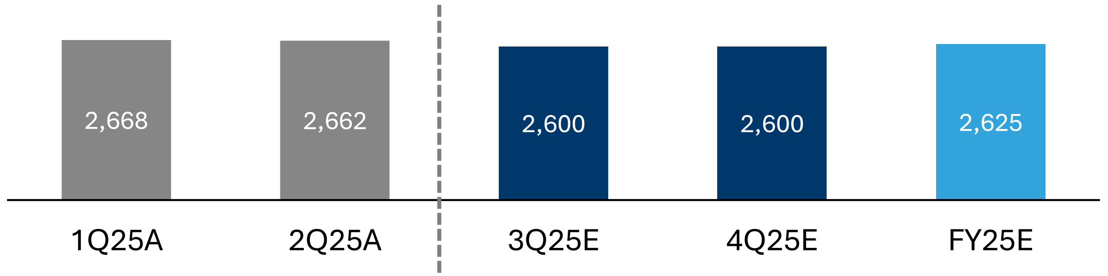
2025 Production Outlook

Northeast Appalachia Quarterly Production

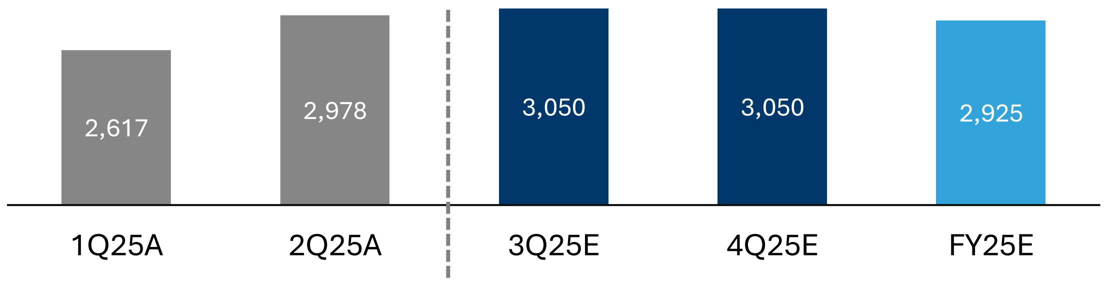
(MMcfe/d)



	1Q25A	2Q25A	3Q25E	4Q25E	FY25E
Rigs	2	2	2	3	2 – 3
Crews	2	2	2	2	2

Haynesville Quarterly Production

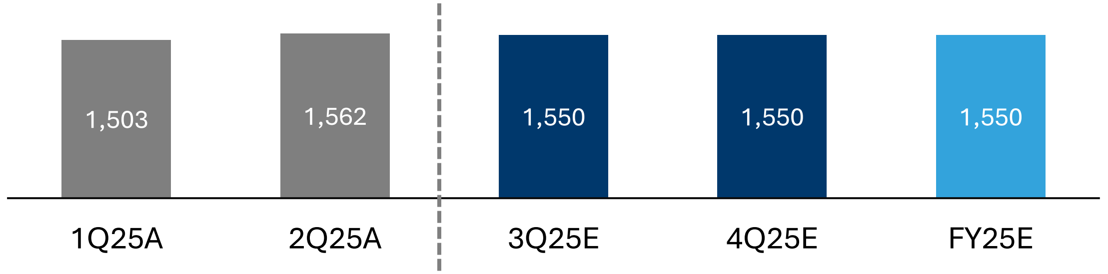
(MMcfe/d)



	1Q25A	2Q25A	3Q25E	4Q25E	FY25E
Rigs	7	7	7	7	7
Crews	3	4	4	3	3 – 4

Southwest Appalachia Quarterly Production

(MMcfe/d)



	1Q25A	2Q25A	3Q25E	4Q25E	FY25E
Rigs	2	2	2	2	2
Crews	2	1	1	1	1 – 2

- 59 2Q25 TILs generated production growth in Haynesville and SW App, while holding NE App flat
- Base optimization analytics and advanced algorithms used to maximize uptime across combined assets
- Production expected to be relatively flat through 2H25
- Now expect to deliver similar well count to original FY25 guidance with fewer annual rigs

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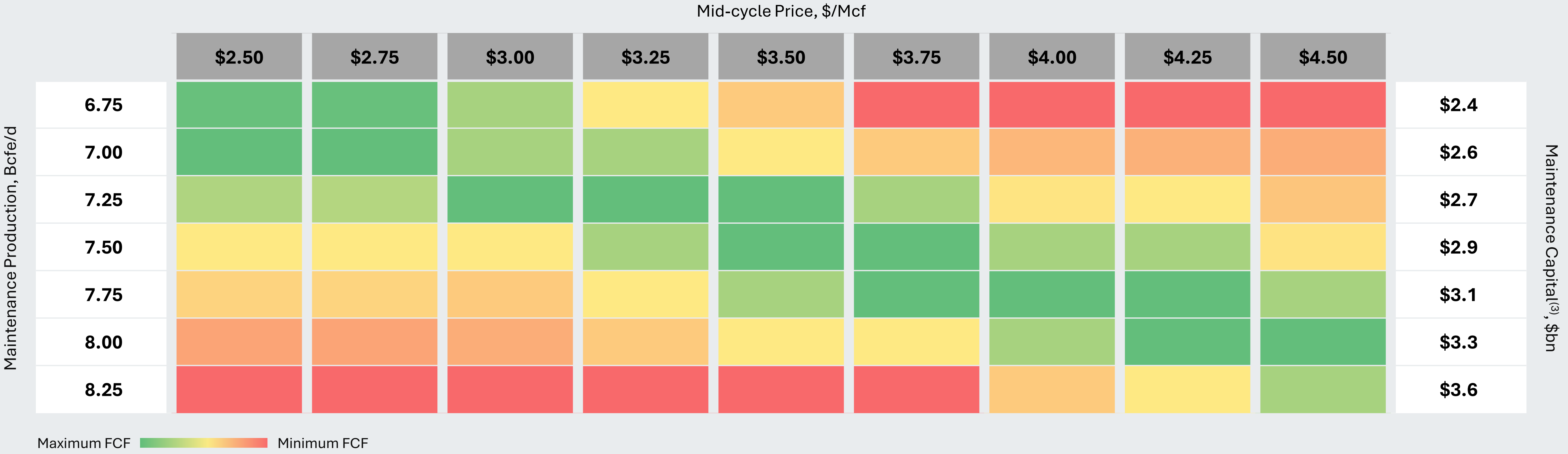
Optimizing Maintenance Production to Maximize Free Cash Flow[1]

Centering activity to deliver ~7.5 Bcfe/d through-cycle maximizes FCF at mid-cycle prices between $3.50 to $4.00

Illustrative Annual FCF[2] at Various Mid-cycle Prices, Maintenance Production and Capital



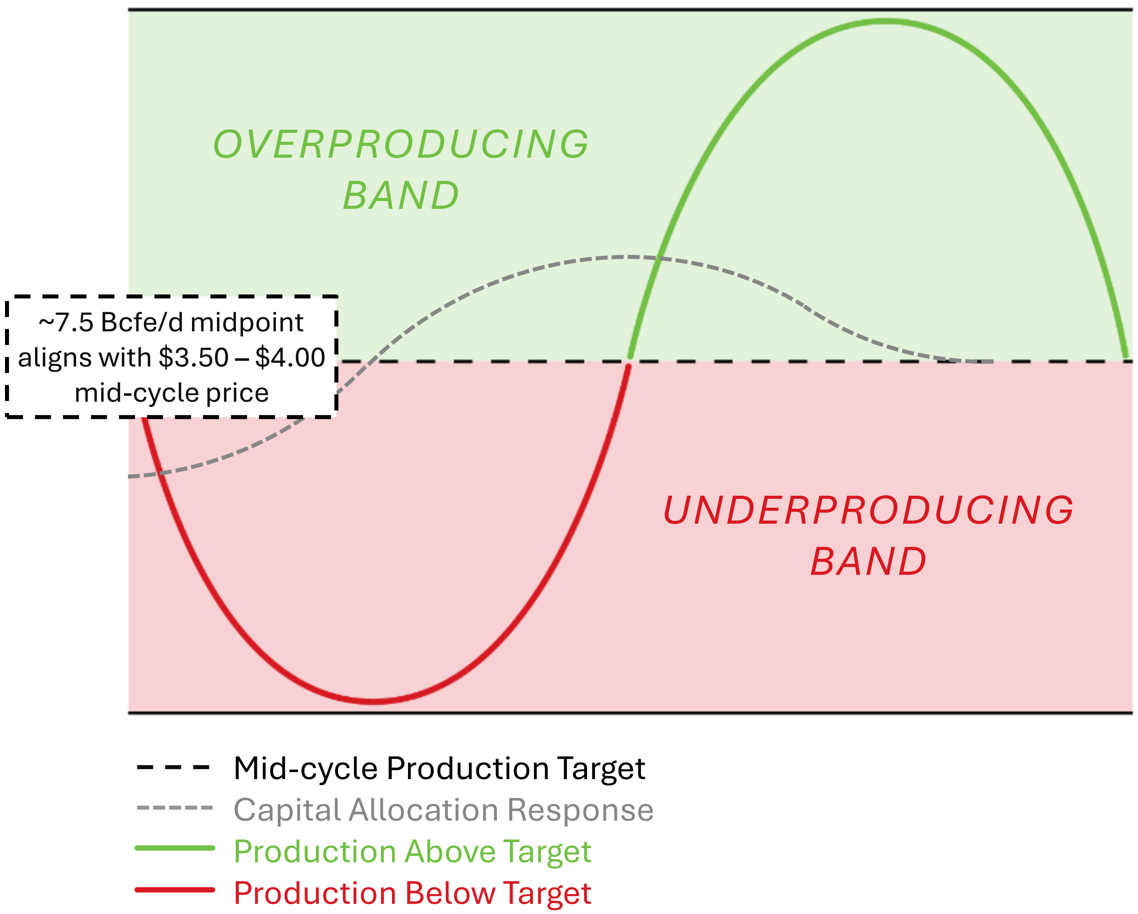
*For a given mid-cycle price Outlook (e.g., column)

Selected mid-cycle production target is continually evaluated for changing market dynamics

(1) FCF is a non-GAAP financial measure, see Appendix for more information
(2) Modeled FCF is not specific to a particular forward year, but representative of run-rate / maintenance production and capital at a given price excluding any hedges and inclusive of all forecasted synergies
(3) Total capital inclusive of D&C, non-D&C field and non-D&C corporate; utilizes current cost assumptions (no inflation) as of February 2025

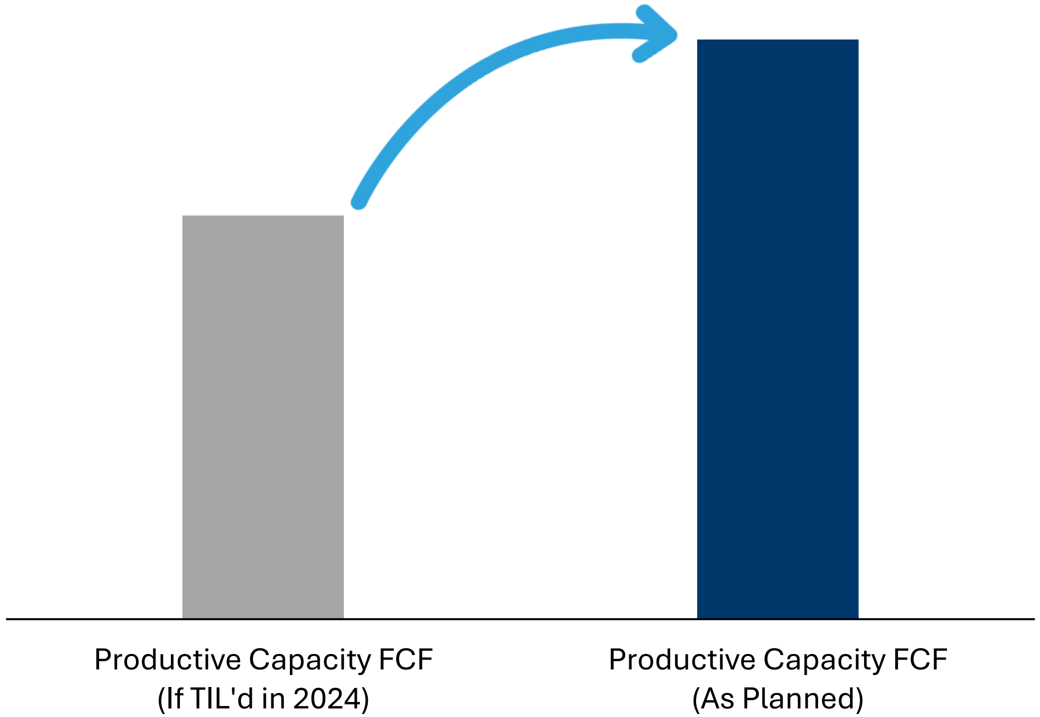
Productive Capacity Success Story

Illustrative Productive Capacity Strategy



2024 Productive Capacity Generated Significant Value

~$225mm increase in FCF[1] over first 12 months of volume from productive capacity wells[2]



(1) FCF is a non-GAAP financial measure, see Appendix for more information
(2) Calculated as the difference between FCF that would have been generated in the 12-month period following the original TIL date for the ~140 wells deferred versus the FCF generated in the 12-month period following the actual, or currently scheduled, TIL date

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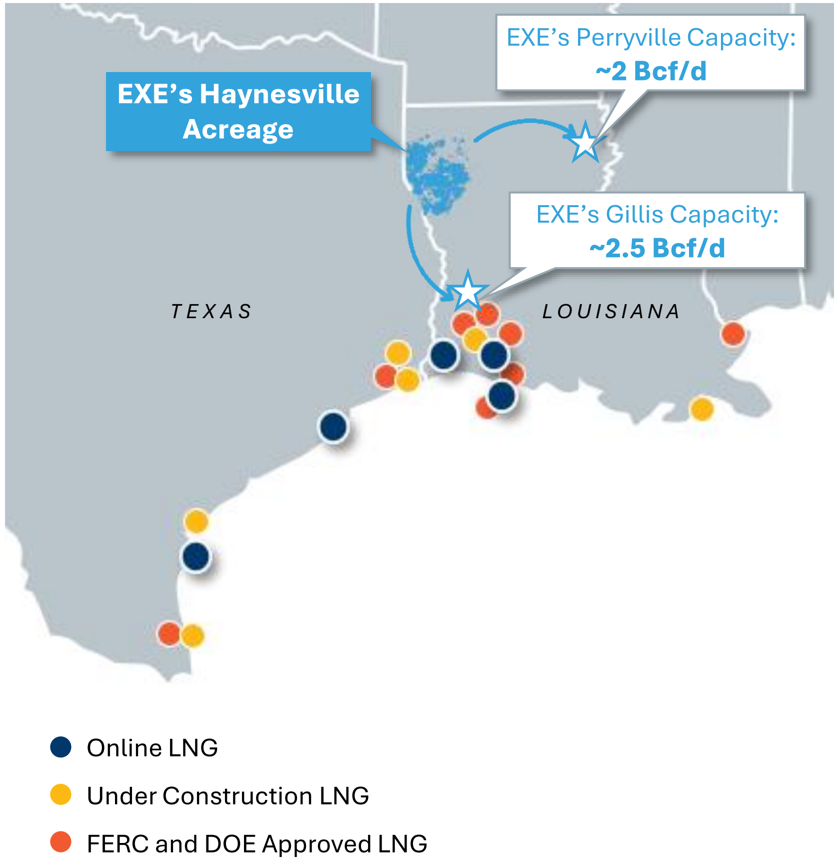
Haynesville Positioned to Capture Premium Gas Markets

Advantaged transportation portfolio provides deliverability, diversification and flexibility



- **EXE Haynesville Marketing Portfolio**
  - Portfolio exposure is balanced between growing LNG demand and Southeast power demand sourced from Perryville
  - ~2.5 Bcf/d of capacity to Gillis, directly connected to premium markets in the LNG corridor
  - ~2 Bcf/d of capacity to the growing Perryville market
  - Connected portfolio provides flexibility to find and optimize price between competing demand sources
- **LNG Demand is Expected to Drive Higher Realizations**
  - >30 Bcf/d of expected LNG demand from existing and under construction facilities by 2029
  - Further upside from additional projects and expansions under consideration
  - New areas of global demand emerging with largest being in Southeast Asia

Enhanced Capital Returns Framework

▪ Tranche 1 – Annual Base Dividend

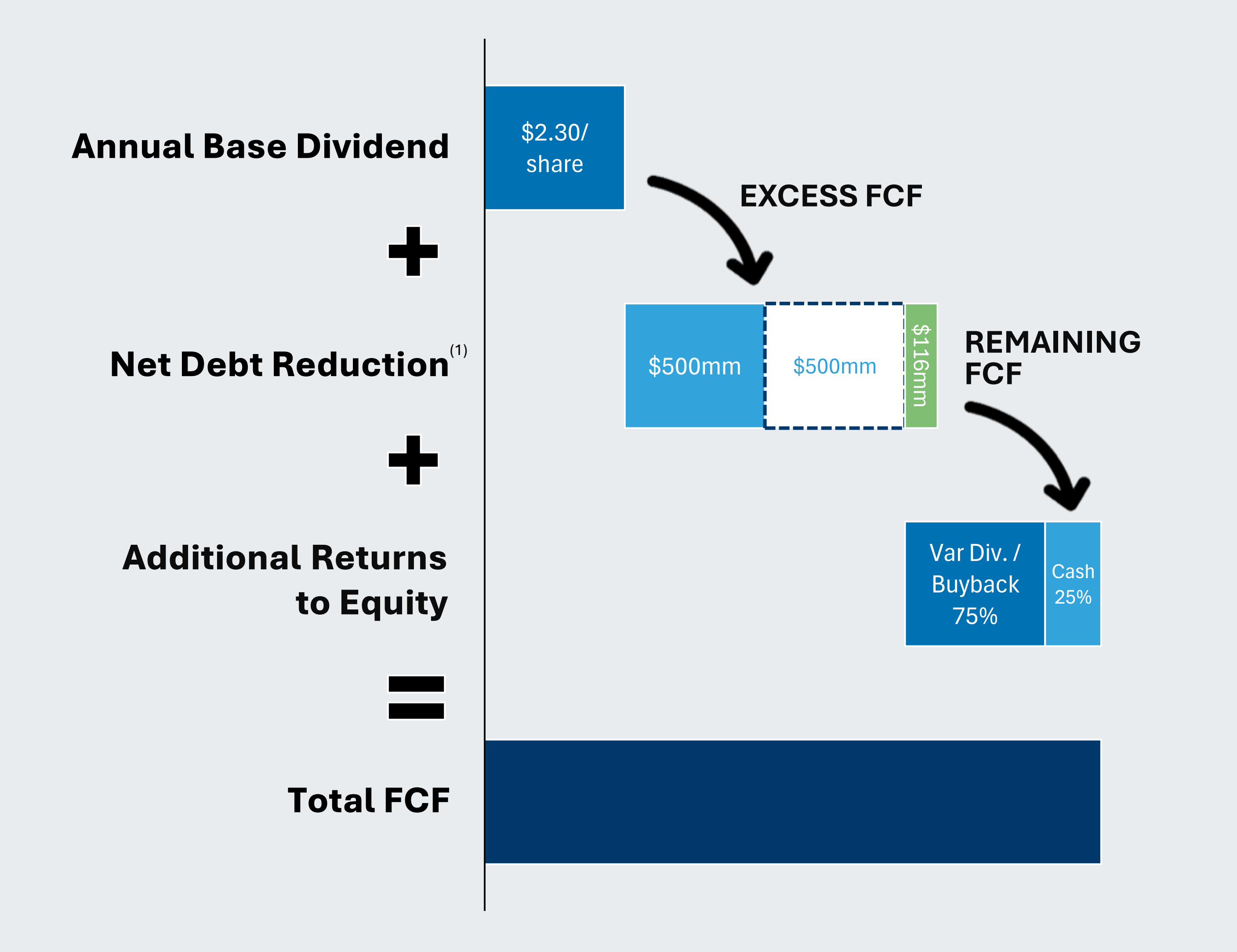
- $2.30/share
- Remains priority and is paid through-cycle
- 2Q25 DPS of $0.575/sh to be paid in September
- ~$274mm base dividend returned for 1H25

▪ Tranche 2 – Net Debt Reduction

- Increasing full year 2025 from $500mm to $1.0bn
- Pursuing a multi-year deleveraging effort to improve through-cycle balance sheet capacity

▪ Tranche 3 – Additional Returns to Equity

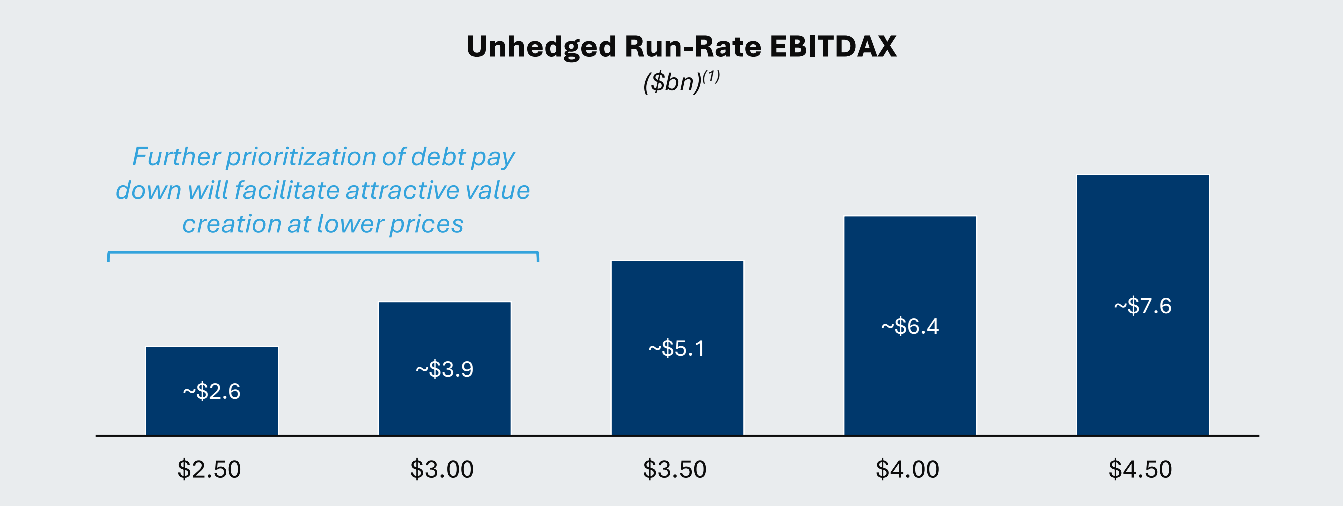
- 75% of remaining FCF in form of equity return (variable dividend or share repurchases)
- ~$100mm share repurchases and ~$211mm variable dividend returned for 1H25

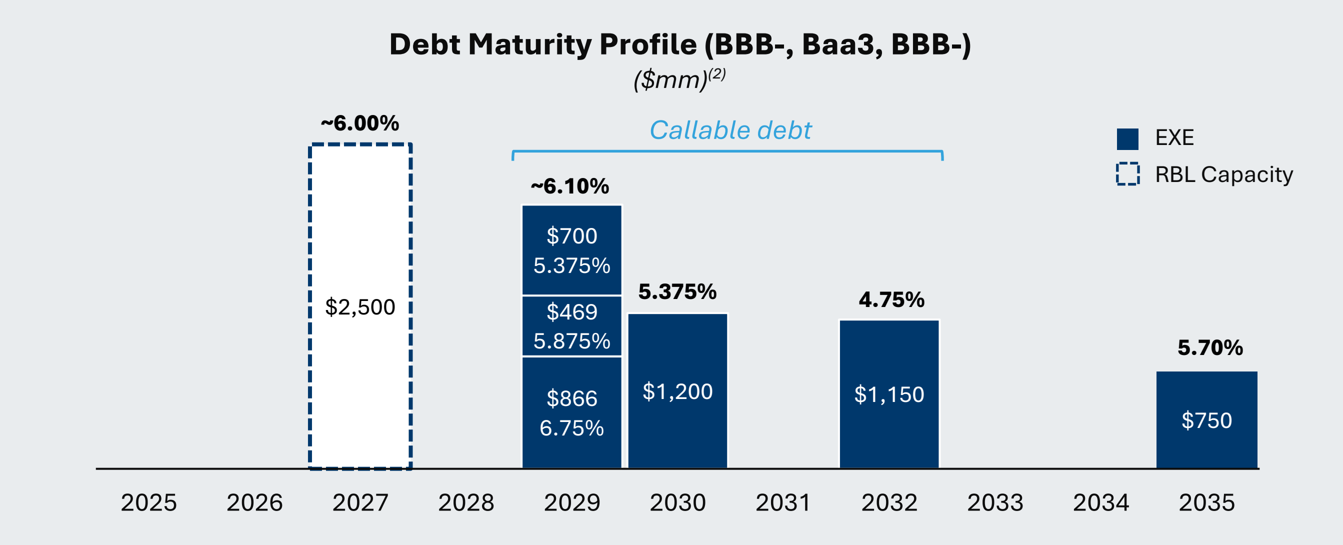


(1) $116mm related to Eagle Ford divestitures

Investment Grade Balance Sheet Supports Through-Cycle Value Creation

- Current balance sheet is strong, however additional deleveraging creates more capacity at cycle-lows
- Pursuing a multi-year deleveraging effort to improve through-cycle balance sheet capacity
- Deleveraging should occur at good prices to facilitate more consistent and aggressive payouts through-cycle
- If market conditions change, we remain flexible to pivot to more aggressive repurchasing





(1) Assumes $70/bbl WTI and 40% NGL
(2) As of 6/30/2025

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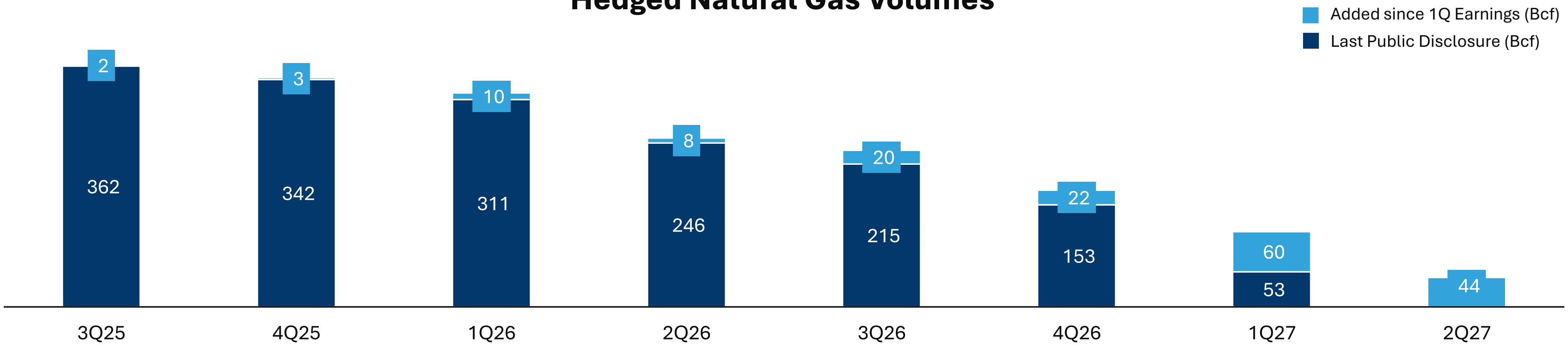
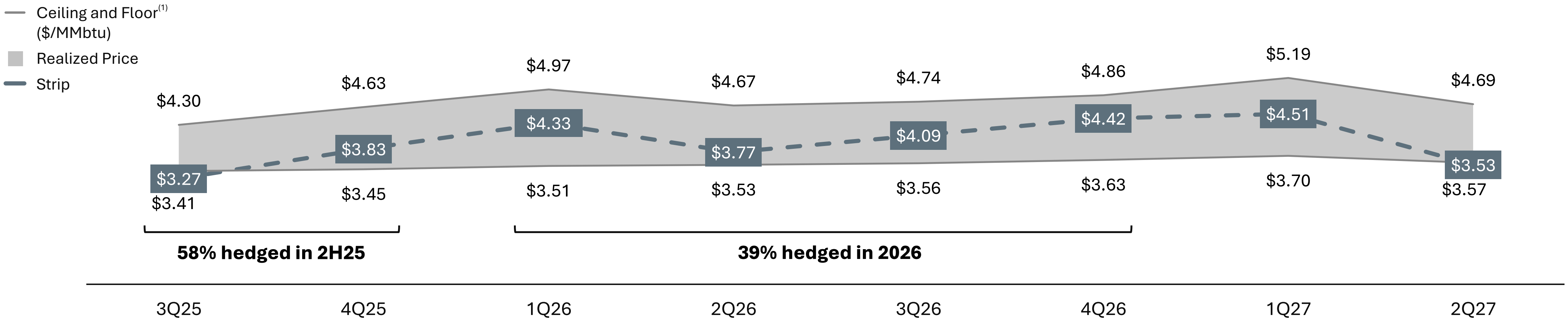
Current Hedge Position Preserves Upside and Downside Protection

Hedged Natural Gas Volumes



Current Hedge Book Supports Near-Term Realizations and Preserves Upside



(1) As of 7/22/2025

2024 Sustainability Performance Highlights

Inaugural report highlights our commitments and progress

- Achieved 100% Responsibly Sourced Gas (RSG) across portfolio (MiQ and EO100™)
- Serious Incident and Fatality (SIF) program adoption for proactive safety prevention
- Net zero Scope 1 and 2 GHG emissions target by 2035
- Employee and executive compensation tied to sustainability performance
- Consistent stakeholder engagement through materiality assessment, local and virtual meetings and community investment
- Partnering with local government agencies and nonprofits for freshwater and habitat conservation program

Transparent and measurable disclosures:

0.13
Combined TRIR

12.2
million bbls recycled produced water

100%
produced water recycled in NE App

2.6
Scope 1 and 2 Greenhouse gas emissions intensity[(1)]

0.02%
Scope 1 Methane emissions intensity[(2)]

Download the report at expandenergy.com/sustainability

(1) Calculated as metric tons CO_2e / gross operated Mboe produced
(2) Calculated as volume methane emissions / volume gross natural gas produced

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Expanding Returns, Expanding Opportunities

Attractive, Connected Portfolio

Premium rock, returns, runway with access to premium markets

Peer-leading Returns

Most efficient operator with proven track record of delivering returns to shareholders

Resilient Financial Foundation

Investment Grade balance sheet provides strategic through-cycle advantages

Responsible Stewardship

Connecting affordable, reliable and lower carbon energy to markets in need

Appendix

2Q 2025 EARNINGS

Management's Guidance as of July 29, 2025

Bold / Italicized = updated guidance range

Production (MMcfe/d)	2Q25A	3Q25E	2025E
Total Production	7,202	7,150 – 7,250	7,000 – 7,200
Haynesville	2,978	~3,050	***~2,925***
Northeast Appalachia	2,662	~2,600	***~2,625***
Southwest Appalachia	1,562	~1,550	***~1,550***

Capital Expenditures ($mm)	2Q25A	3Q25E	2025E
Total D&C	$531	$500 – $550	***$2,100 – $2,200***
Haynesville	58%	~56%	~54%
Northeast Appalachia	19%	~20%	~22%
Southwest Appalachia	23%	~24%	~24%
Other Capex (Field)[1]	$86	$115 – $135	***$300 – $325***
Other Capex (Corporate)[2]	$38	$45 – $55	$175 – $200
Total Base Capital Expenditures	$655	$660 – $740	***$2,575 – $2,725***
Productive Capacity Program	$72	~$100	***up to $275***
Total Capital Expenditures	$727	$760 – $840	***$2,850 – $3,000***

Operating Costs (per Mcfe of Projected Production)	2Q25A	2025E
Production Expense	$0.23	***$0.23 – $0.28***
Gathering, Processing and Transportation (GP&T)	$0.97	$0.96 – $1.11
GP&T Expense	*$0.86*	*$0.90 – $1.00*
GP&T FMV Liability[3]	*$0.11*	*$0.06 – $0.11*
Severance and Ad Valorem Taxes	$0.08	$0.08 – $0.10
General and Administrative	$0.06	***$0.07 – $0.09***
Depreciation, Depletion and Amortization	$1.17	$1.05 – $1.15

Corporate Expenses ($mm)	2Q25A	2025E
Interest Expense	$60	***$225 – $250***
Cash Income Tax Ranges at Flat Prices	$82	
$3.50		***$50 – $100***
$4.00		***$100 – $150***
$4.50		***$150 – $200***

Basis Differentials (excluding hedges)	2Q25A	2025E
Estimated (E) Basis Deduct to NYMEX Prices, based on 7/22/2025 Strip Prices:		
Natural Gas ($/Mcf)	($0.51)	($0.30) – ($0.45)
Oil ($/bbl)	($9.27)	($10.00) – ($12.00)
NGL (% of WTI)	36%	35% – 45%

(1) Other Capex (Field) includes Leasehold and Workover expenses
(2) Other Capex (Corporate) includes PP&E, Capitalized G&A and Interest expenses
(3) GP&T fair market liability related to the amortization of the $175mm – $225mm net liability for out-of-market contracts assumed in the Southwestern merger

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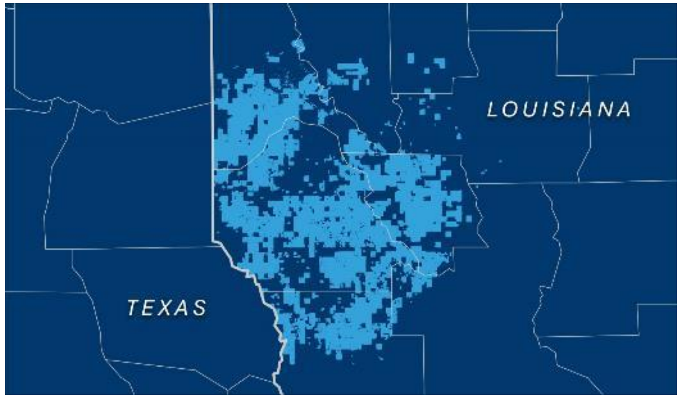
2Q25 EXE Business Unit Results

	Haynesville		NE Appalachia		SW Appalachia	
Production (MMcfe/d)	2,978		2,662		1,562	
Production Expense ($/Mcfe)	$0.25		$0.15		$0.33	
Differential to NYMEX ($/Mcf)	$(0.32)		$(0.79)		$(0.33)	
GP&T ($/Mcfe)	$0.66		$0.84		$1.27	
Rigs	7		2		2	
Spuds (by zone)	Haynesville 22	Bossier 2	Lower 6	Upper[1] 7	Marcellus 7	Utica 5
TILs (by zone)	Haynesville 16	Bossier 13	Lower 8	Upper[1] 12	Marcellus 10	Utica 0
D&C Capex ($mm)	$348		$117		$138	
Total Capital ($mm)	$419		$139		$169	

(1) NE Appalachia Upper Marcellus category is inclusive of hybrid wells

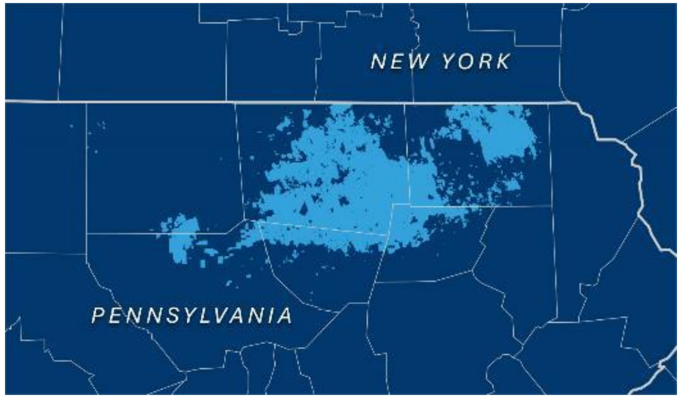
Haynesville, Northeast and Southwest Appalachia Sales Points



Haynesville Sales Points

DEDUCT FROM NYMEX ($)[1]			
Historical Avg		*Current*	
CGML	($0.28)	CGML	($0.26)
TGT	($0.25)	TGT	($0.23)
9% of NYMEX		**7% of NYMEX**	

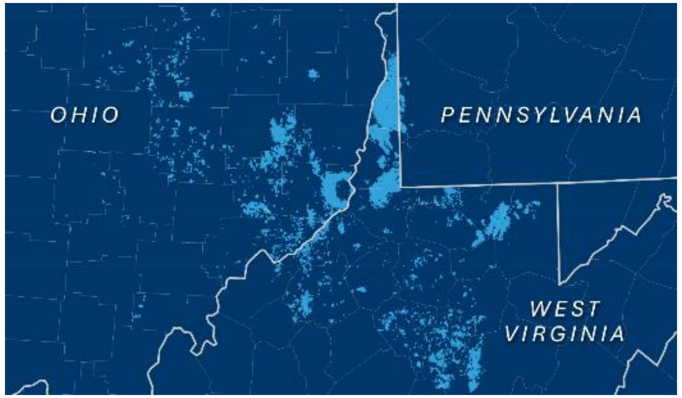
HAYNESVILLE TOTAL PRODUCTION[2]	
CGML	15%
TGT	20%
Other (primarily NYMEX)	65%



Northeast Appalachia Sales Points

DEDUCT FROM NYMEX ($)[1]			
Historical Avg		*Current*	
TETCO M3	+$0.05	TETCO M3	($0.20)
Leidy	($0.76)	Leidy	($0.89)
Eastern Gas	($0.82)	Eastern Gas	($0.93)
TGP 300L	($0.83)	TGP 300L	($0.97)
20% of NYMEX		**15% of NYMEX**	

NORTHEAST APPALACHIA TOTAL PRODUCTION[2]			
In Basin	55%	Out of Basin	45%
Leidy	30%	TETCO M3	25%
Eastern Gas	20%	NYMEX	20%
TGP 300L	5%		



Southwest Appalachia Sales Points

DEDUCT FROM NYMEX ($)[1]			
Historical Avg		*Current*	
TCO	($0.67)	TCO	($0.73)
TrunklineZ1A	($0.28)	TrunklineZ1A	($0.30)
CG Onshore	($0.13)	CG Onshore	($0.04)
CGML	($0.28)	CGML	($0.26)
Rex Zone 3	($0.18)	Rex Zone 3	($0.29)
15% of NYMEX		**8% of NYMEX**	

SOUTHWEST APPALACHIA TOTAL PRODUCTION[2]	
TCO	40%
TrunklineZ1A	25%
CG Onshore	15%
CGML	10%
Rex Zone 3	10%

(1) Historical prices based on NYMEX contract settlement for January 2023 – December 2024; current prices based on NYMEX settled and future prices for January 2025 – December 2026, strip as of 7/22/2025
(2) Percentage of production based on 2025 Production Guidance

Being LNG Ready Will Create Meaningful Value and Enhance Returns

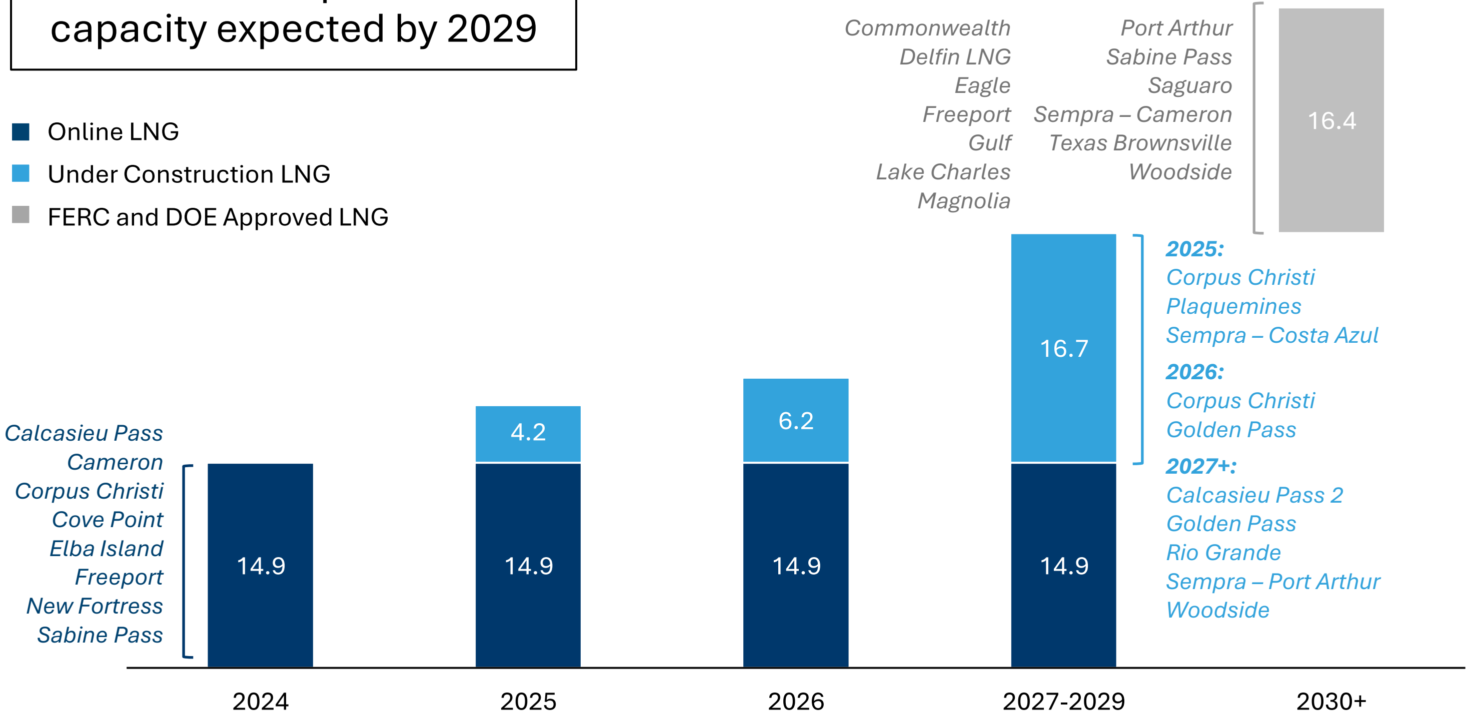
- EXE portfolio uniquely positioned to meet growing LNG demand
- Currently selling ~2 Bcf/d to LNG export facilities
- ~2.5 Bcf/d of EXE deliverability to LNG corridor

Growing Exports Expected to be Significant to U.S. Gas Demand

(U.S. LNG Capacity, Bcf/d)[(1)]

~32 Bcf/d

of total LNG export capacity expected by 2029



(1) Volumes per FERC; Inservice estimations from EIA and project websites

Revised Tax Outlook

- Passage of the One Big, Beautiful Bill (OBBB) on July 4 restores the incentives for domestic capital investment and research expenditures, as well as creates parity amongst types of capital investments for purposes of computing the book minimum tax

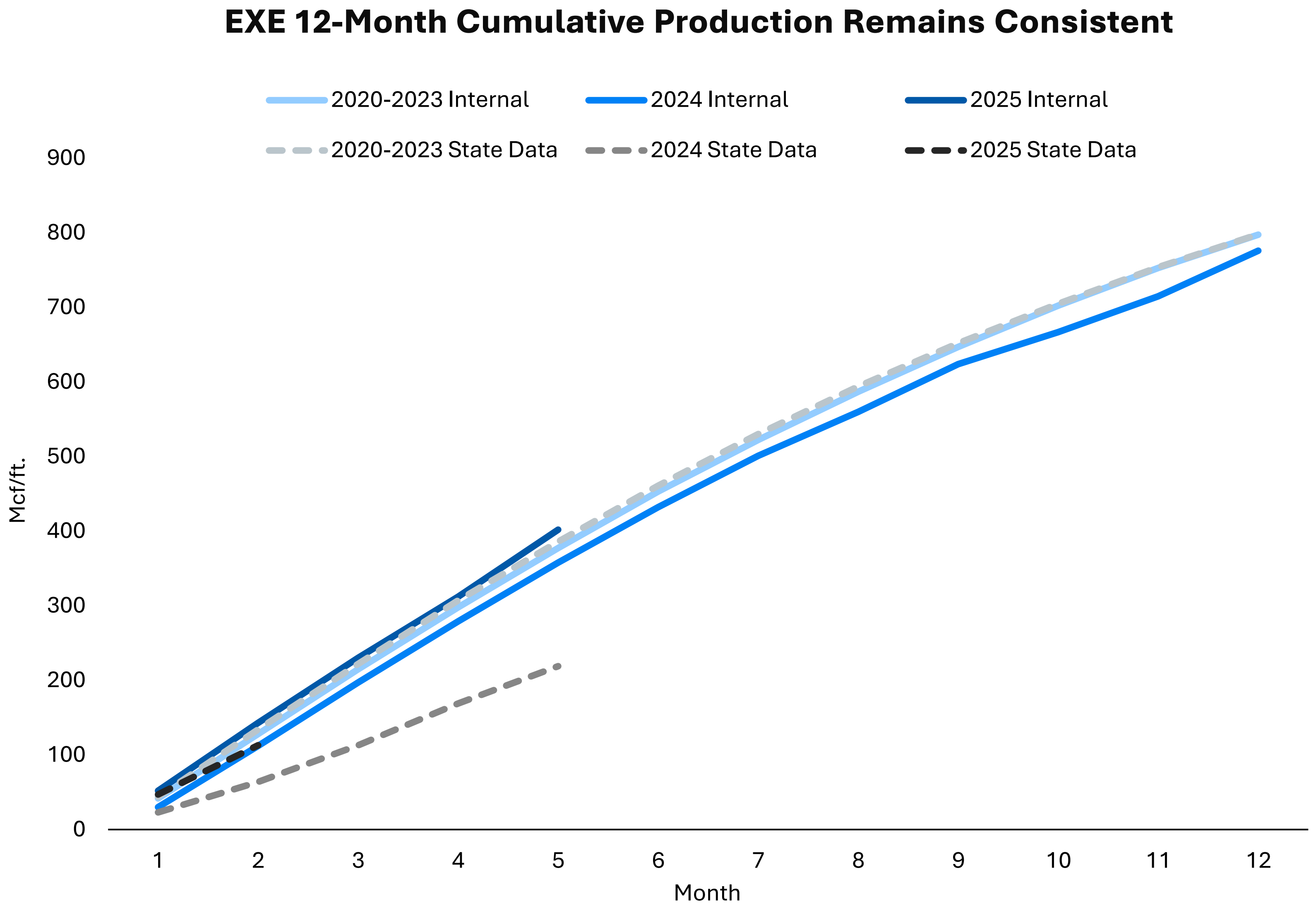
Most Impactful Provisions	**Effective Beginning**	**Reduces Regular Tax**	**Reduces Book Min Tax**
Restoration of 100% bonus depreciation	2025	✓	✓
Parity of treatment of intangible drilling and completion costs for purposes of book minimum tax	2026		✓

- Though we are still subject to the book minimum tax – the result of the OBBB is that taxes are lower than before and certain provisions retroactively reduce our current-year taxes

Cash Income Tax Ranges at Flat Prices ($mm)	**2025E**	**Outlook**
$3.50	~~*$175 – $225*~~ *$50 – $100*	*22% – 24% Book Tax Rate (30% current / 70% deferred)*
$4.00	~~*$300 – $350*~~ *$100 – $150*	
$4.50	~~*$450 – $500*~~ *$150 – $200*	

Haynesville Productivity by Vintage

- Haynesville productivity remains strong and on trend with historical performance
- Current public data is missing wells located in most productive area of Haynesville
- Impacted data includes 2024 and 2025 well sets
- EXE productivity expected to align with historical trend once corrected



Minimal Near-term Impact from Tariffs

- Supply Chain outlook unchanged from 1Q as service pricing offsets potential tariff impacts
  - OFS demand remains near recent-term lows
  - Weak oil outlook weighing on Permian focused rig and frac activity
  - Forecasting minimal tariff-related impact to near-term spend
  - No supply surety risk related to tariffs
  - Contractual measures, existing inventory, and strategic negotiations preserves and extends pre-tariff cost structure and limits future impact
- Long-term impact remains dependent upon outcome and scale of tariff program

Illustrative AFE Components and Cost Trends

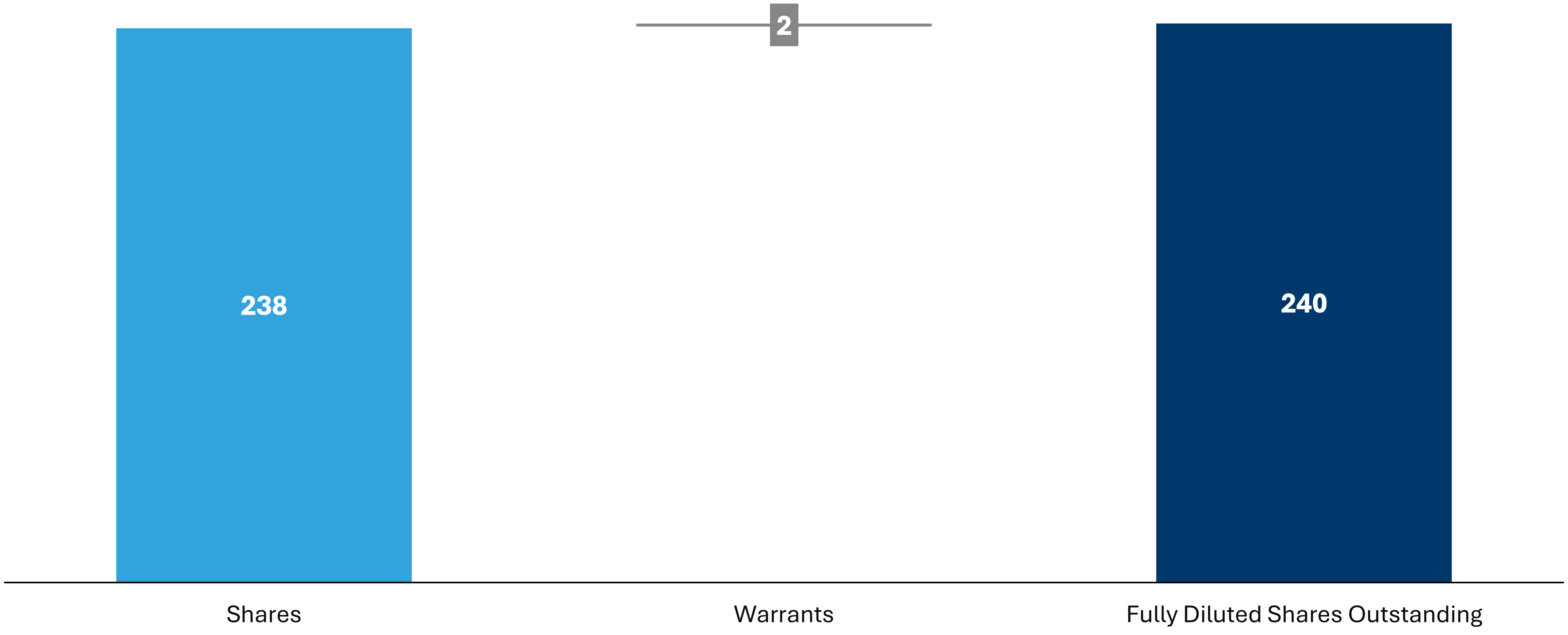
YE24 compared to YE25 expectations

PHASE	SUB-CATEGORY	% OF AFE	TREND
Drilling	OCTG	8% – 12%	↗
	Rigs	8% – 12%	↘
	Cement	1% – 3%	↔
	Mud & Directional	6% – 8%	↘
Frac	Pressure Pumping	12% – 20%	↘
	Sand & Logistics	8% – 20%	↘
Commodity / Other	Fuel	4% – 8%	Variable
	Labor	4% – 8%	↔
	Other	~10%	CPI
Total		**0% – 2% deflation**	

↘ Single digit decline ↔ Flat ↗ Single digit increase

Fully Diluted Share Count Breakdown

Shares in millions, as of 7/24/2025



Reducing Risk, Protecting Returns Through Hedge Program

NATURAL GAS										ESTIMATED NYMEX GAS SETTLEMENT ($mm)				
	SWAPS		COSTLESS COLLARS			THREE-WAY COLLARS								
Date	Volume Bcf	Price $/Mcf	Volume Bcf	Bought Put $/Mcf	Sold Call $/Mcf	Volume Bcf	Bought Put $/Mcf	Sold Call $/Mcf	Sold Put $/Mcf	Date	$2.00 NYMEX	$3.00 NYMEX	$4.00 NYMEX	$5.00 NYMEX
1Q 2025	103.9	3.40	182.4	3.42	4.65	39.6	3.66	5.88	2.59	1Q 2025	(25)	(25)	(25)	(25)
2Q 2025	103.3	3.46	221.0	3.31	4.34	40.0	3.66	5.88	2.59	2Q 2025	30	30	30	30
3Q 2025	101.0	3.54	222.2	3.31	4.35	40.5	3.66	5.88	2.59	3Q 2025	368	126	(33)	(192)
4Q 2025	63.3	3.59	240.6	3.37	4.70	40.5	3.66	5.88	2.59	4Q 2025	498	154	(48)	(212)
FY 2025	**371.5**	**$3.48**	**866.2**	**$3.35**	**$4.51**	**160.6**	**$3.66**	**$5.88**	**$2.59**	**FY 2025**	**$871**	**$285**	**($76)**	**($399)**
1Q 2026	34.9	4.13	286.4	3.43	5.08	–	–	–	–	1Q 2026	485	163	5	(105)
2Q 2026	39.8	4.04	213.9	3.43	4.77	–	–	–	–	2Q 2026	388	134	2	(117)
3Q 2026	40.3	4.02	194.8	3.47	4.88	–	–	–	–	3Q 2026	368	133	(2)	(94)
4Q 2026	31.1	4.14	144.2	3.52	5.01	–	–	–	–	4Q 2026	285	110	4	(57)
FY 2026	**146.0**	**$4.08**	**839.3**	**$3.46**	**$4.94**	**–**	**–**	**–**	**–**	**FY 2026**	**$1,526**	**$540**	**$9**	**($373)**
1Q 2027	–	–	113.0	3.70	5.19	–	–	–	–	1Q 2027	192	79	1	(9)
2Q 2027	–	–	44.6	3.57	4.69	–	–	–	–	2Q 2027	70	26	(0)	(15)
3Q 2027	–	–	1.8	3.70	4.85	–	–	–	–	3Q 2027	3	1	0	(0)
FY 2027	–	–	**159.4**	**$3.67**	**$5.05**	**–**	**–**	**–**	**–**	**FY 2027**	**$265**	**$106**	**$1**	**($24)**

Hedge position as of 7/22/2025

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Reducing Risk, Protecting Returns Through Hedge Program

NATURAL GAS LIQUIDS								
Date	C2 SWAPS		C3 SWAPS		C4 SWAPS		C5 SWAPS	
	Volume MBbl	Price $/gal	Volume MBbl	Price $/gal	Volume MBbl	Price $/gal	Volume MBbl	Price $/gal
1Q 2025	900	0.25	603	0.73	135	0.84	203	1.35
2Q 2025	910	0.25	546	0.74	137	0.84	205	1.35
3Q 2025	920	0.25	552	0.74	138	0.84	207	1.35
4Q 2025	920	0.25	552	0.74	138	0.84	207	1.35
FY 2025	**3,650**	**$0.25**	**2,253**	**$0.74**	**548**	**$0.84**	**821**	**$1.35**
FY 2026	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**

ESTIMATED NGL SETTLEMENT ($mm)				
Date	$0.25	$0.50	$1.00	$1.50
1Q 2025	(9)	(9)	(9)	(9)
2Q 2025	(1)	(1)	(1)	(1)
3Q 2025	24	5	(33)	(71)
4Q 2025	24	5	(33)	(71)
FY 2025	**$38**	**$0**	**($76)**	**($152)**
FY 2026	**–**	**–**	**–**	**–**

Hedge position as of 7/22/2025

Reducing Risk, Protecting Returns Through Hedge Program

CRUDE OIL										ESTIMATED NYMEX WTI SETTLEMENT ($mm)				
Date	SWAPS		COSTLESS COLLARS			THREE-WAY COLLARS				Date	$60.00 WTI	$70.00 WTI	$80.00 WTI	$90.00 WTI
	Volume MBbl	Price $/Bbl	Volume MBbl	Bought Put $/Bbl	Sold Call $/Bbl	Volume MBbl	Bought Put $/Bbl	Sold Call $/Bbl	Sold Put $/Bbl					
1Q 2025	41	77.66	–	–	–	270	70.00	94.67	60.00	1Q 2025	0	0	0	0
2Q 2025	–	–	–	–	–	364	70.00	94.63	60.00	2Q 2025	2	2	2	2
3Q 2025	–	–	–	–	–	368	70.00	94.63	60.00	3Q 2025	4	0	0	0
4Q 2025	–	–	–	–	–	322	65.71	86.81	55.71	4Q 2025	2	0	0	(1)
FY 2025	**41**	**$77.66**	**–**	**–**	**–**	**1,324**	**$68.96**	**$92.73**	**$58.96**	**FY 2025**	**$8**	**$2**	**$2**	**$1**
1Q 2026	–	–	–	–	–	225	70.00	83.32	60.00	1Q 2026	2	0	0	(2)
FY 2026	**–**	**–**	**–**	**–**	**–**	**225**	**$70.00**	**$83.32**	**$60.00**	**FY 2026**	**$2**	**$0**	**$0**	**($2)**

Hedge position as of 7/22/2025

Hedged Financial Basis

Date	HAYNESVILLE						NORTHEAST APPALACHIA							
	CGT MAINLINE		TETCO WLA		TGT Z1		TETCO M3		TGP Z4 300L		LEIDY		EASTERN GAS	
	Volume Bcf	Avg. Price $/Mcf	Volume Bcf	Avg. Price $/Mcf	Volume Bcf	Avg. Price $/Mcf	Volume Bcf	Avg. Price $/Mcf	Volume Bcf	Avg. Price $/Mcf	Volume Bcf	Avg. Price $/Mcf	Volume Bcf	Avg. Price $/Mcf
1Q 2025	5.4	(0.21)	–	–	35.3	(0.24)	15.8	1.03	0.9	(0.75)	15.8	(0.66)	2.3	(0.64)
2Q 2025	0.9	(0.23)	–	–	28.4	(0.24)	16.1	(0.86)	–	–	28.2	(1.00)	3.8	(0.79)
3Q 2025	0.9	(0.23)	–	–	28.8	(0.24)	19.3	(0.86)	–	–	28.5	(1.00)	6.9	(0.89)
4Q 2025	0.3	(0.23)	–	–	19.8	(0.23)	18.9	0.32	–	–	20.0	(0.86)	6.9	(0.79)
FY 2025	**7.5**	**($0.22)**	**–**	**–**	**112.3**	**($0.23)**	**70.2**	**($0.12)**	**0.9**	**($0.75)**	**92.5**	**($0.91)**	**19.8**	**($0.81)**
1Q 2026	–	–	1.4	0.11	14.9	(0.22)	32.6	0.42	–	–	18.0	(0.76)	9.9	(0.90)
2Q 2026	–	–	1.4	0.11	–	–	37.1	(0.68)	–	–	16.4	(1.12)	17.1	(1.07)
3Q 2026	–	–	1.4	0.11	–	–	37.5	(0.68)	–	–	16.6	(1.12)	17.3	(1.07)
4Q 2026	–	–	1.4	0.11	–	–	24.8	(0.33)	–	–	9.9	(1.00)	10.1	(1.03)
FY 2026	**–**	**–**	**5.5**	**$0.11**	**14.9**	**($0.22)**	**132.0**	**($0.34)**	**–**	**–**	**60.8**	**($1.00)**	**54.3**	**($1.03)**
1Q 2027	–	–	–	–	–	–	3.6	0.98	–	–	3.6	(0.83)	0.9	(0.90)

Hedge position as of 7/22/2025

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Shareholder Returns (Unaudited)

($ and shares in millions, except per share amounts)		Six Months Ended June 30, 2025
Net Cash Provided by Operating Activities (GAAP)	**$**	**2,418**
Less cash capital expenditures		(1,220)
Less contributions to investments		(9)
Less cash paid for common stock base dividends (Tranche 1)		(274)
Less net debt reduction (Tranche 2)		(500)
Free Cash Flow (Non-GAAP) after Tranche 1 and Tranche 2	**$**	**415**
Free Cash Flow (Non-GAAP) Available for Additional Returns to Equity (Tranche 3)(1)	**$**	**311**
Less common stock repurchases		(100)
Amount Available for Variable Dividend	**$**	**211**
Common shares outstanding at 7/24/2025 (2)		238
Variable dividend payable per common share in September 2025	$	0.89
Base dividend payable per common share in September 2025	$	0.575
Total dividend payable per common share in September 2025	$	1.465

(1) Represents approximately 75% of the free cash flow after Tranche 1 and Tranche 2
(2) Basic common shares outstanding as of 7/24/2025 assumes no exercise of warrants between 7/24/2025 and dividend record date

Non-GAAP Financial Measures

As a supplement to the financial results prepared in accordance with U.S. GAAP, Expand Energy's quarterly earnings presentations contain certain financial measures that are not prepared or presented in accordance with U.S. GAAP. These non-GAAP financial measures include Adjusted EBITDAX, Free Cash Flow, Adjusted Free Cash Flow, Net Debt and Total Capitalization.
A reconciliation of each financial measure to its most directly comparable GAAP financial measure is included in the following tables. Management believes these adjusted financial measures are a meaningful adjunct to earnings and cash flows calculated in accordance with GAAP because (a) management uses these financial measures to evaluate the company's trends and performance, (b) these financial measures are comparable to estimates provided by securities analysts, and (c) items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items. Due to the forward-looking nature of projected Adjusted EBITDAX, projected Free Cash Flow and projected Adjusted Free Cash Flow used herein, management cannot reliably predict certain of the necessary components of the most directly comparable forward-looking GAAP measures. Accordingly, the Company is unable to present a quantitative reconciliation of such forward-looking non-GAAP financial measures to their most directly comparable forward-looking GAAP financial measures without unreasonable effort. Amounts excluded from these non-GAAP measures in future periods could be significant.

Expand Energy's definitions of each non-GAAP measure presented herein are provided below. Because not all companies or securities analysts use identical calculations, Expand Energy's non-GAAP measures may not be comparable to similarly titled measures of other companies or securities analysts.

Adjusted EBITDAX: Adjusted EBITDAX is defined as net income (loss) before interest expense, income tax expense (benefit), depreciation, depletion and amortization expense, exploration expense, unrealized (gains) losses on natural gas and oil derivatives, separation and other termination costs, (gains) losses on sales of assets, and certain items management believes affect the comparability of operating results. Adjusted EBITDAX is presented as it provides investors an indication of the company's ability to internally fund exploration and development activities and service or incur debt. Adjusted EBITDAX should not be considered an alternative to, or more meaningful than, net income (loss) or net cash provided by (used in) operating activities as presented in accordance with GAAP.

Free Cash Flow: Free Cash Flow is defined as net cash provided by (used in) operating activities less cash capital expenditures. Free Cash Flow is a liquidity measure that provides investors additional information regarding the company's ability to service or incur debt and return cash to shareholders. Free Cash Flow should not be considered an alternative to, or more meaningful than, net cash provided by (used in) operating activities, or any other measure of liquidity presented in accordance with GAAP.

Adjusted Free Cash Flow: Adjusted Free Cash Flow is defined as net cash provided by (used in) operating activities less cash capital expenditures and cash contributions to investments, adjusted to exclude certain items management believes affect the comparability of operating results. Adjusted Free Cash Flow is a liquidity measure that provides investors additional information regarding the company's ability to service or incur debt and return cash to shareholders. Adjusted Free Cash Flow should not be considered an alternative to, or more meaningful than, net cash provided by (used in) operating activities, or any other measure of liquidity presented in accordance with GAAP.

Net Debt: Net Debt is defined as GAAP total debt excluding premiums, discounts, and deferred issuance costs less cash and cash equivalents. Net Debt is useful to investors as a widely understood measure of liquidity and leverage, but this measure should not be considered as an alternative to, or more meaningful than, total debt presented in accordance with GAAP.

Total Capitalization: Total Capitalization is defined as Net Debt plus total stockholders' equity and is used in the Net Debt to Capitalization ratio.

Reconciliation of Net Income (Loss) to Adjusted EBITDAX (Unaudited)

($ in millions)	Three Months Ended June 30, 2025	Three Months Ended March 31, 2025	Three Months Ended December 31, 2024	Three Months Ended September 30, 2024	Trailing Twelve Months	Three Months Ended June 30, 2024
Net Income (Loss) (GAAP)	**$ 968**	**$ (249)**	**$ (399)**	**$ (114)**	**$ 206**	**$ (227)**
Adjustments:						
Interest expense	60	59	64	20	203	20
Income tax expense (benefit)	260	(70)	(22)	(44)	124	(68)
Depreciation, depletion and amortization	769	711	647	335	2,462	348
Exploration	20	7	3	2	32	3
Unrealized (gains) losses on natural gas and oil derivatives	(842)	969	490	160	777	262
Separation and other termination costs	–	–	–	–	–	23
Gains on sales of assets	(4)	–	(2)	(2)	(8)	(2)
Other operating expense, net[1]	32	26	267	23	348	16
(Gains) losses on purchases, exchanges or extinguishments of debt	(3)	–	(1)	–	(4)	2
Contract amortization	(72)	(52)	(57)	–	(181)	–
Other	(12)	(6)	(26)	(15)	(59)	(19)
Adjusted EBITDAX (Non-GAAP)	**$ 1,176**	**$ 1,395**	**$ 964**	**$ 365**	**$ 3,900**	**$ 358**

Reconciliation of Net Cash Provided by Operating Activities to Adjusted Free Cash Flow (Unaudited)

($ in millions)	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024
Net Cash Provided by Operating Activities (GAAP)	**$ 1,322**	**$ 209**
Cash capital expenditures	(657)	(302)
Free Cash Flow (Non-GAAP)	**665**	**(93)**
Cash paid for merger expenses	32	–
Cash contributions to investments	(5)	(26)
Adjusted Free Cash Flow (Non-GAAP)	**$ 692**	**$ (119)**

(1) Includes an adjustment for costs incurred related to the Southwestern merger

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Reconciliation of Net Cash Provided by Operating Activities to Adjusted EBITDAX (Unaudited)

($ in millions)		Three Months Ended June 30, 2025		Three Months Ended June 30, 2024
Net Cash Provided by Operating Activities (GAAP)	**$**	**1,322**	**$**	**209**
Changes in assets and liabilities		(321)		131
Interest expense		60		20
Current income tax expense		89		–
Share-based compensation		(13)		(10)
Other[1]		39		8
Adjusted EBITDAX (Non-GAAP)	**$**	**1,176**	**$**	**358**

Reconciliation of Total Debt to Total Capitalization (Unaudited)

($ in millions)		June 30, 2025
Total Debt (GAAP)	**$**	**5,122**
Premiums, discounts and issuance costs on debt		13
Principal Amount of Debt		**5,135**
Cash and cash equivalents		(731)
Net Debt (Non-GAAP)		**4,404**
Total stockholders' equity		17,937
Total Capitalization (Non-GAAP)	**$**	**22,341**

(1) Includes an adjustment for costs incurred related to the Southwestern merger