



COTERRA

# 1Q25 Earnings Presentation

May 2025



# Disclaimer

## Cautionary Statement Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of federal securities laws. Forward-looking statements are not statements of historical fact and reflect Coterra's current views about future events. Such forward-looking statements include, but are not limited to, statements about returns to shareholders, growth rates, enhanced shareholder value, reserves estimates, future financial and operating performance and goals and commitment to sustainability and ESG leadership, strategic pursuits and goals, and other statements that are not historical facts contained in this presentation. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "predict," "potential," "possible," "may," "should," "could," "would," "will," "strategy," "outlook" and similar expressions are also intended to identify forward-looking statements. We can provide no assurance that the forward-looking statements contained in this presentation will occur as projected and actual results may differ materially from those projected. Forward-looking statements are based on current expectations, estimates and assumptions that involve a number of risks and uncertainties that could cause actual results to differ materially from those projected. These risks and uncertainties include, without limitation, the volatility in commodity prices for crude oil and natural gas; cost increases; changes in U.S. and international economic policy (including tariffs and retaliatory tariffs and the impacts thereof); the effect of future regulatory or legislative actions; the impact of public health crises, including pandemics (such as the coronavirus pandemic) and epidemics and any related governmental policies or actions on Coterra's business, financial condition and results of operations; actions by, or disputes among or between, the Organization of Petroleum Exporting Countries and other producer countries; market factors; market prices (including geographic basis differentials) of oil and natural gas; impacts of inflation; labor shortages and economic disruption (including as a result of the pandemic or geopolitical disruptions such as the war in Ukraine or the conflict in the Middle East); determination of reserves estimates, adjustments or revisions, including factors impacting such determination such as commodity prices, well performance, operating expenses and completion of Coterra's annual PUD reserves process, as well as the impact on our financial statements resulting therefrom; the presence or recoverability of estimated reserves; the ability to replace reserves; environmental risks; drilling and operating risks; results of future marketing and drilling activities (including seismicity and similar data); exploration and development risks; competition; the ability of management to execute its plans to meet its goals; and other risks inherent in Coterra's businesses. In addition, the declaration and payment of any future dividends, whether regular base quarterly dividends, variable dividends or special dividends, will depend on Coterra's financial results, cash requirements, future prospects and other factors deemed relevant by Coterra's Board. While the list of factors presented here is considered representative, no such list should be considered to be a complete statement of all potential risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. For additional information about other factors that could cause actual results to differ materially from those described in the forward-looking statements, please refer to Coterra's annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other filings with the SEC, which are available on Coterra's website at [www.coterra.com](http://www.coterra.com).

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This presentation includes non-GAAP financial measures, which help facilitate comparison of company performance across periods. For a reconciliation of non-GAAP measures included herein to the nearest corresponding GAAP measure, please see the appendix to this presentation.

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**COTERRA.COM**

# Coterra Energy – A Differentiated Oil & Natural Gas Company

Consistent, Profitable Growth Through the Commodity Cycles

## Who Is Coterra?

- Culture of Excellence  
*Open, non-siloed organization drives internal debate in which the best ideas prevail*
- Data Driven Approach to Problem Solving  
*Rigorous scientific and financial analysis*
- Technical Teams Driving Value Creation  
*Leveraging AI and custom applications to generate differentiated results*
- Iterative Planning Leads to Improved Outcomes  
*Flexibility is key to maximizing value*
- Conservative and Disciplined Financial Approach  
*Focused on long-term value creation*

## Why Own Coterra?

- Consistent, Profitable Growth & Low Reinvestment  
*Highly capital-efficient portfolio and development program*
- High-Quality Inventory  
*Long-lived, high-return inventory provides competitive advantage*
- Diversified Portfolio Provides Ability to Pivot  
*Ability to redirect capital across three basins*
- Durable Free Cash Flow  
*Balanced oil and natural gas production provides free cash flow stability*
- Peer-Leading Balance Sheet  
*Low leverage, high liquidity and a prudent maturity profile*

# Durable Free Cash Flow Through the Cycles

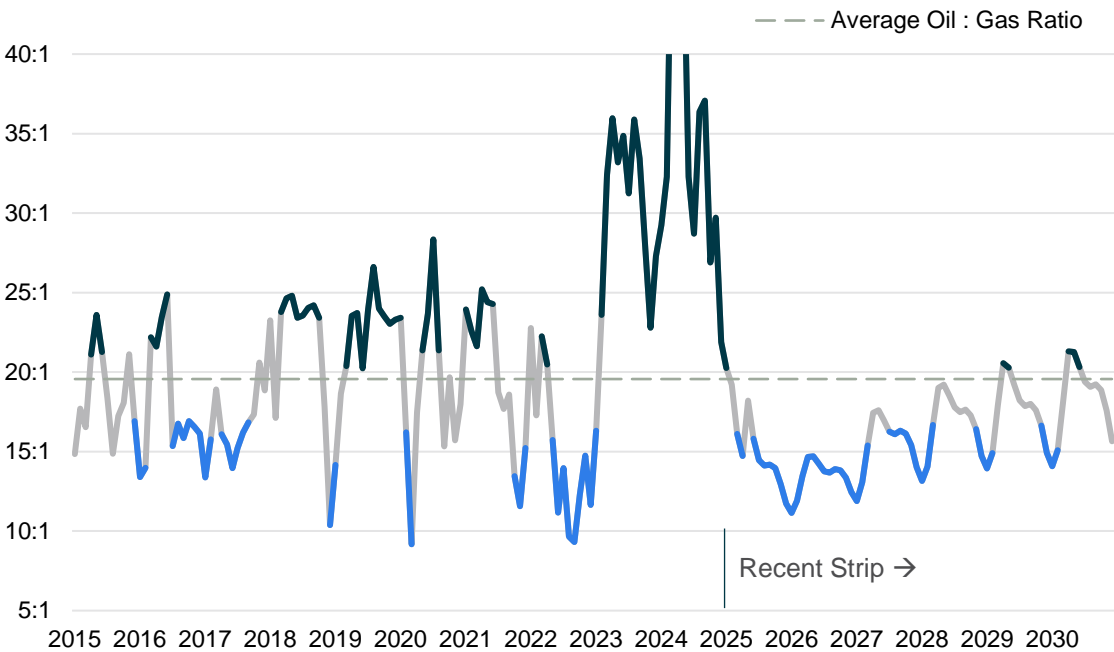
Oil-to-gas price ratios can, and have historically decoupled, especially during periods of extreme volatility

## Uniquely Positioned to Weather Volatility

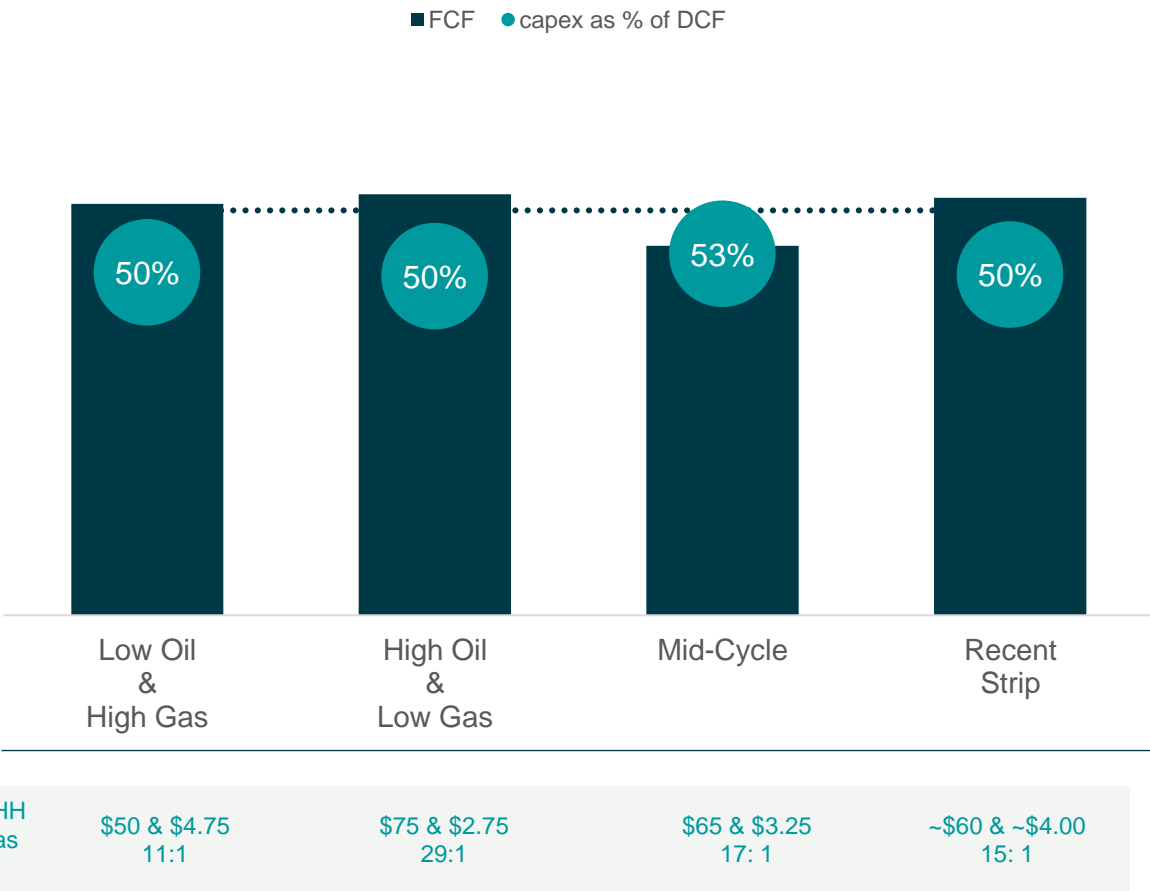
Diversified Commodity Portfolio with Demonstrated Capital Flexibility

### Oil:Gas Ratios

>20:1: **Oil advantaged**, occurred 53% 2015-24, 4% 5-yr Strip  
<17:1: **Gas advantaged**, occurred 32% 2015-24, 58% 5-yr Strip



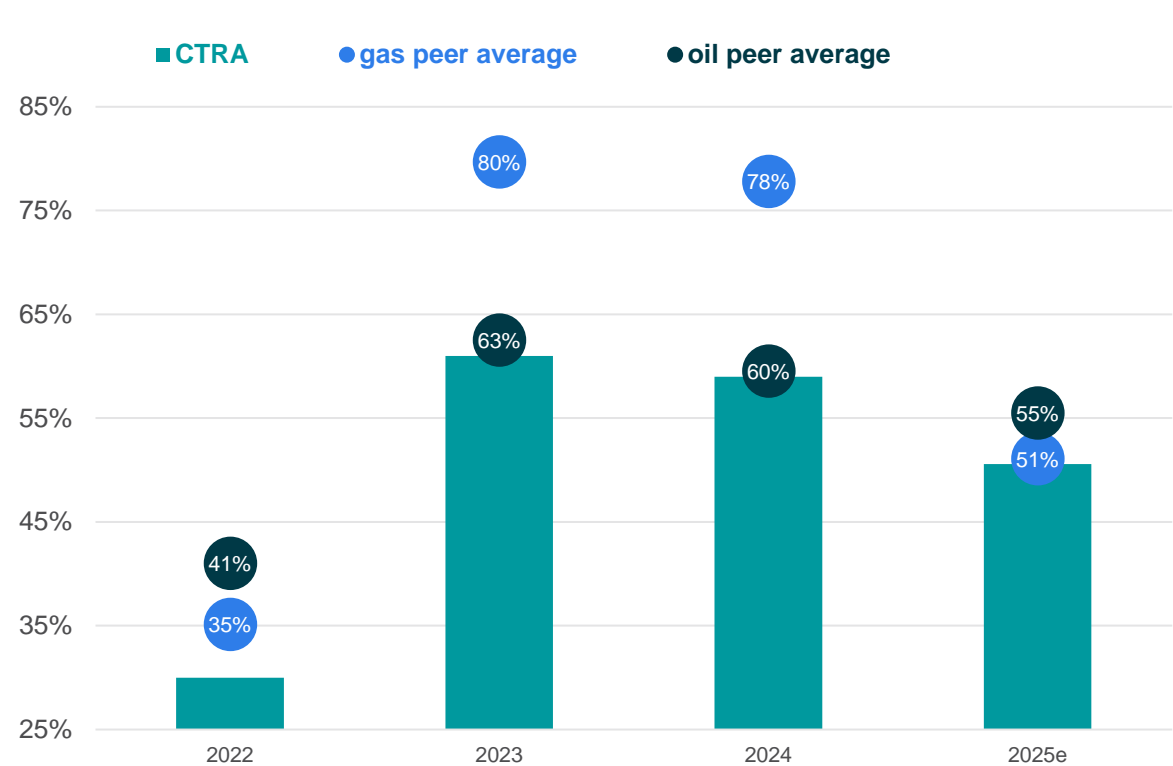
## Resilient Free Cash Flow Through Volatile Commodity Environments



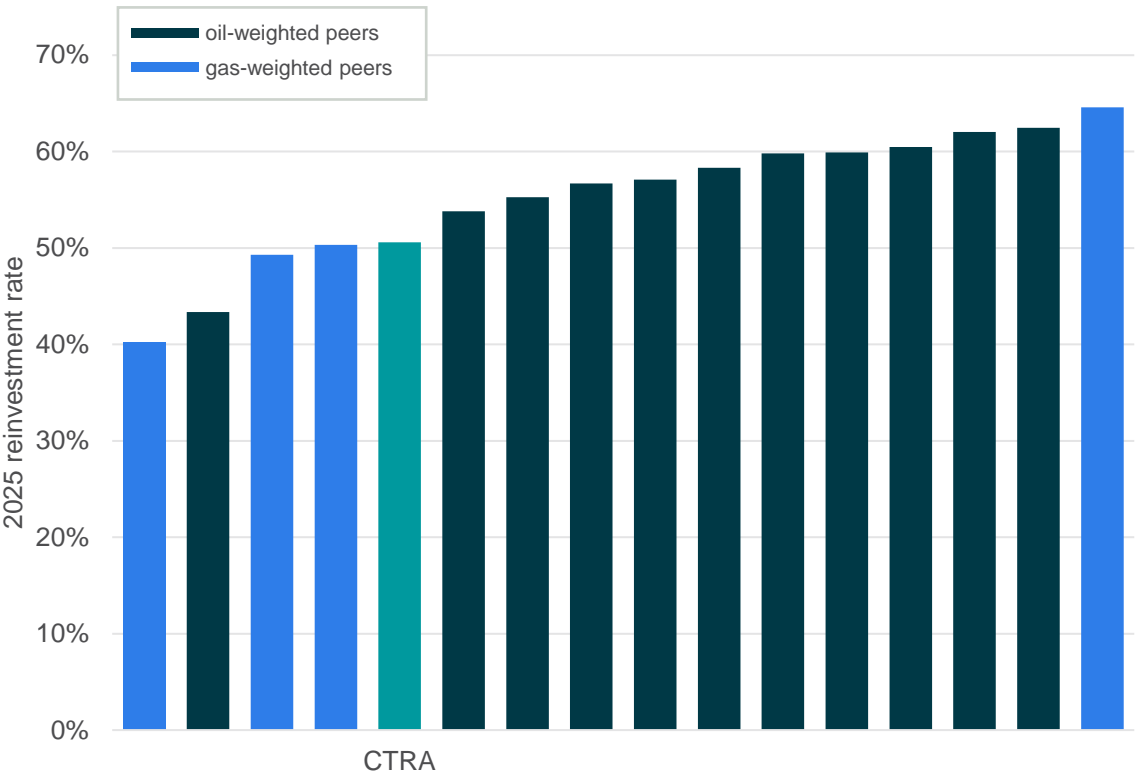
# Disciplined Approach to Capital Investment

Differentiated reinvestment rate through the commodity cycles

## Conservative historical reinvestment rate



## Low reinvestment among peers in 2025



# Improving 2025 Production Guide at Lower Capital

**Lowering 2025 Capital** Range to \$2.0-\$2.3bn | **Reallocating Investment** From Permian Oil to Marcellus Gas | **Increasing BOE and Natural Gas Production Midpoint**



**Strong 1Q25 Results** | Beat the mid-point of oil production, BOE production, and capex guidance & the high-end of gas production guidance; Delivered \$663 million of Free Cash Flow



**Optimizing Investment Allocation for Current Environment** | Reducing 2025 capital by \$100 million, and reallocating with oil-weighted activity -\$150 million, natural gas-weighted activity +\$50 million



**Improving 2025 Production Guidance at Lower Capital and Maintaining 3-year Outlook** | Enhanced capital efficiency driven by lower capital spend and high-grading development schedule for current conditions



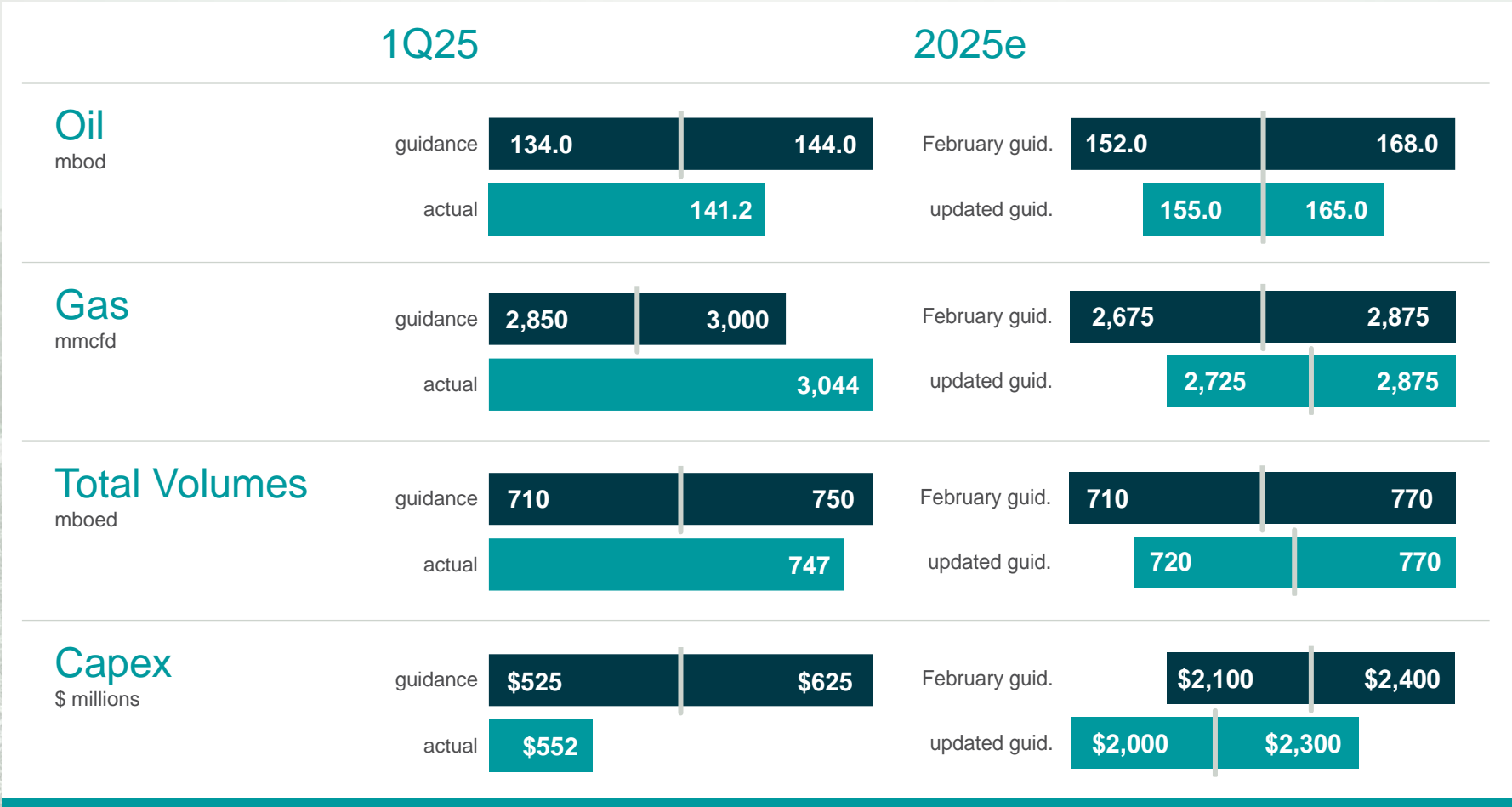
**Durable Free Cash Flow Outlook** | Estimated 2025 Free Cash Flow of \$2.1 billion supported by balanced commodity exposure between oil and natural gas



**Balance Sheet Top-Tier** | Pro forma leverage  $\sim 0.9\times^1$ , retired \$250 million of Term Loans during 1Q

# Beat Midpoint of 1Q25 Production Guidance & Updating Annual Guidance

Higher production & lower capex driving improved capital efficiency



# 2025 Capital Down from February Guide

Lowering annual capital \$100mm: increasing natural gas investment \$50 million, decreasing oil investment \$150 million

## 2025e Capex Summary

- 

**Disciplined Capital Program**  
\$2.0 to \$2.3 billion capex & ~50% reinvestment rate<sup>1</sup>
- 

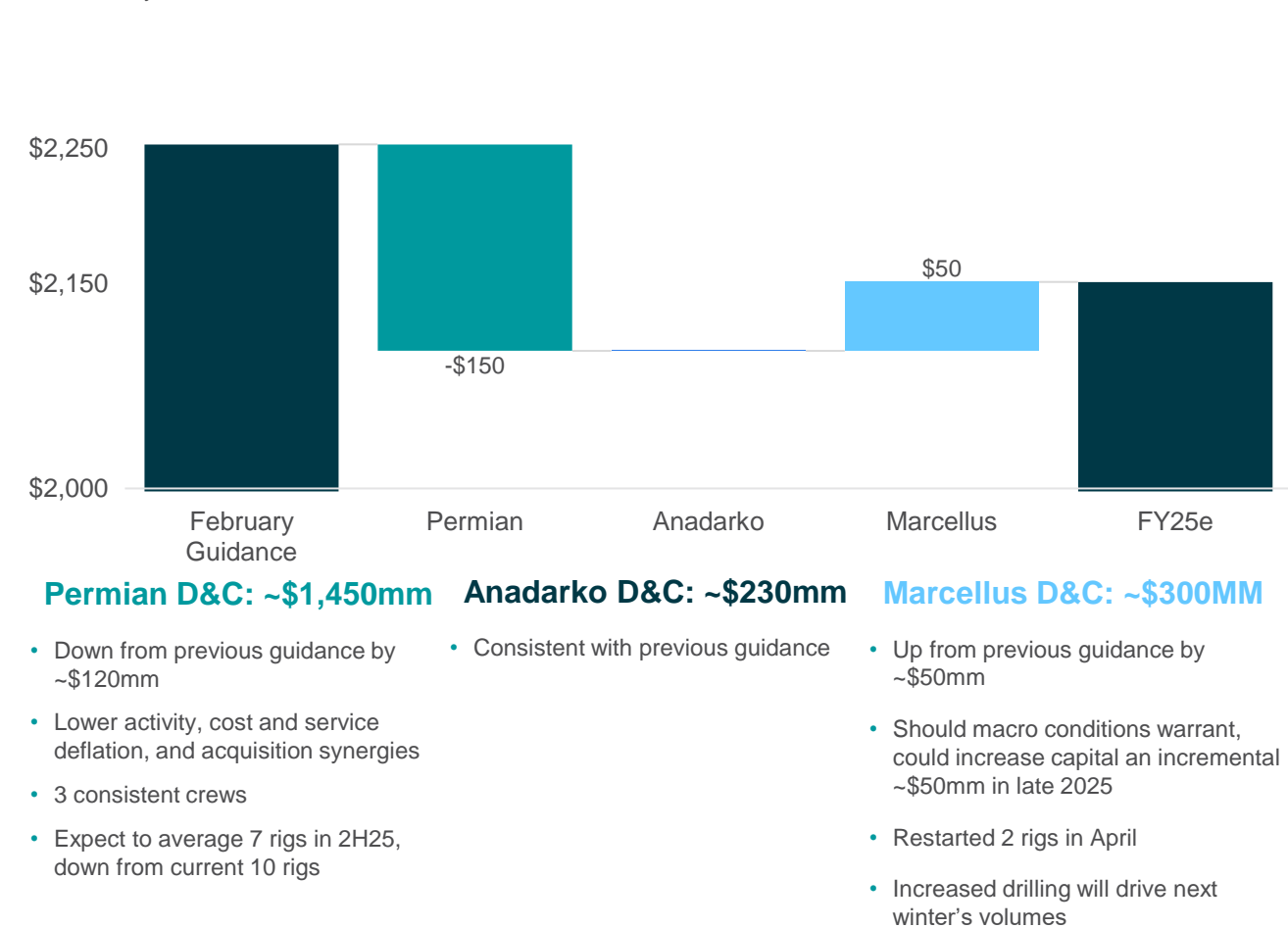
**~\$2.1 billion Free Cash Flow<sup>2</sup>, +69% YoY**  
driven by higher expected commodity prices and disciplined reinvestment
- 

**Production Guidance**  
720-770 mboed | 155-165 mbod | 2,725-2,875 mmcf/d
- 

**Organic Production Growth in 2025e and 2025e-2027e**  
expect 5%+ for oil and 0-5% for BOE and gas

## Capex Walk From February Guidance

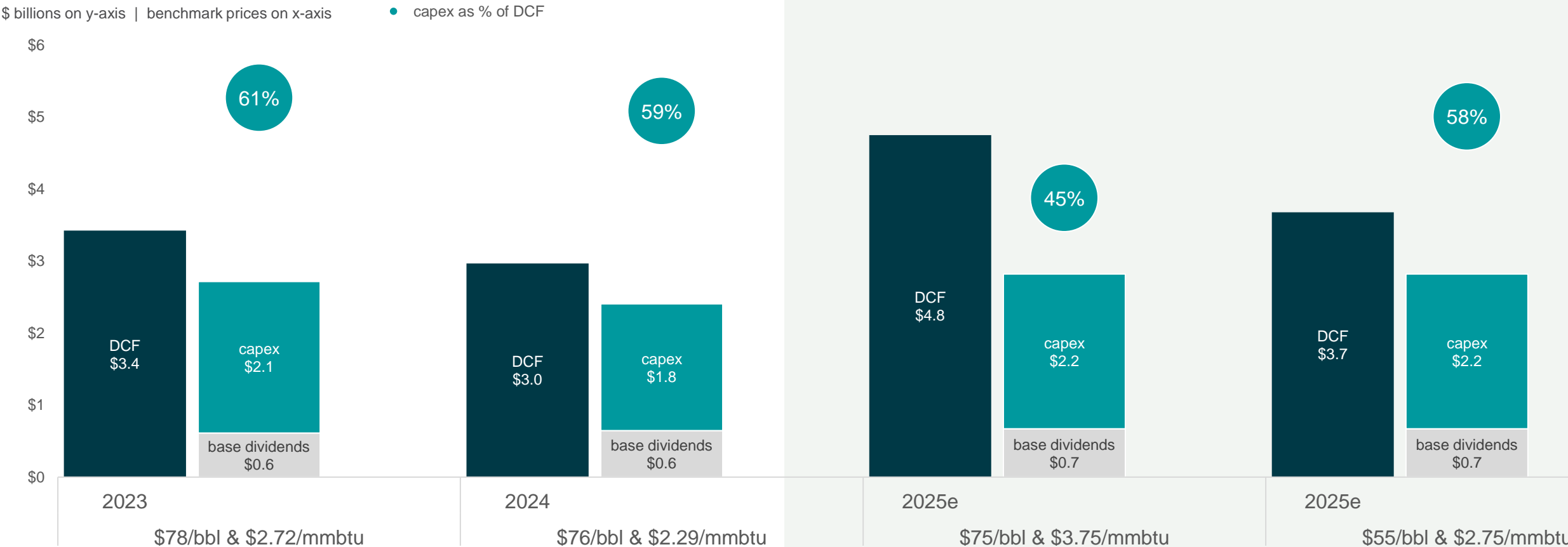
\$ millions on y-axis





# Committed to Capital Discipline & Free Cash Flow Generation

Expect to reinvest ~50-60% of discretionary cash flow at mid-cycle prices

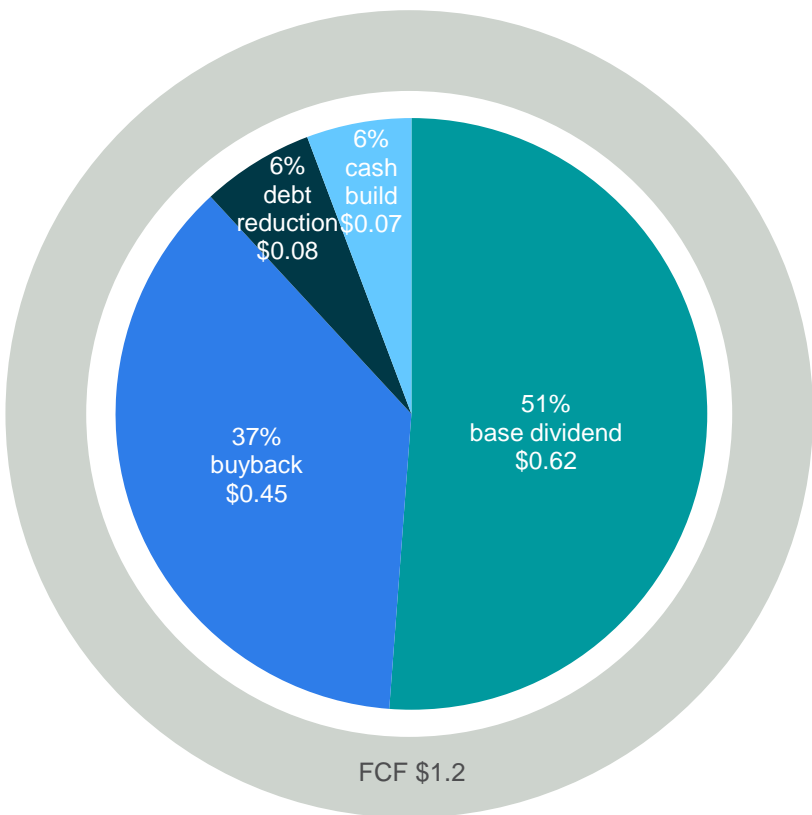


# Committed to Returning Value

\$ billions | Percentages shown are shareholder returns as percentage of Free Cash Flow

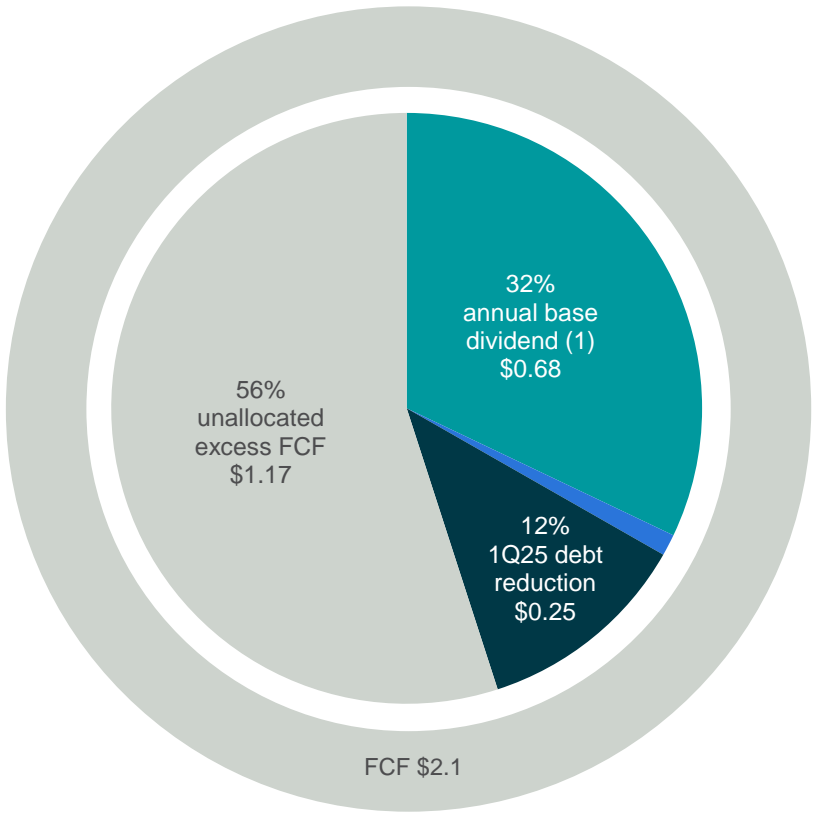
## 2024 FCF \$1.2bn

Returned 89% of FCF to shareholders through dividends & share repurchases, and paid down \$75 million of debt



## 2025e FCF \$2.1bn

see appendix for commodity price assumptions



- In 2025, intend to utilize FCF for base dividend, retirement of term loans (\$750 million outstanding) and opportunistic share repurchases
- Declared 4Q24 dividend of \$0.22 per share, or \$0.88 per share annualized; up 5% YoY
- 3% dividend yield<sup>2</sup>
- \$2.0 billion share repurchase authorization with \$1.1 billion remaining as of March 31, 2025

Note: See appendix for non-GAAP reconciliations and definitions. Dividends shown are declared dividends within the year, not cash paid. Share repurchases shown are on cash basis, which excludes 1% excise tax and any shares that settled after the quarter-end. 2024 debt reduction excluding acquisition financing. 1) base dividend = 1Q25 declared dividends of \$168mm + share count, per cover of 1Q25 10Q \* \$0.66/sh (for remaining 3 quarters of the year). Future dividends are subject to board approval. 2) based on \$25.51 share price as of 4/29/2025.

# Long Runway of High-Quality Inventory

Benchmark price assumptions of \$75/bbl and \$3.75/mmbtu

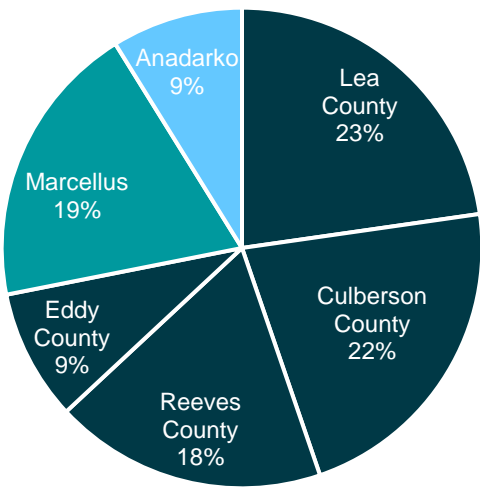
## ~\$31 billion of Economic Capex Opportunities

estimated capex by PVI<sub>10</sub> bucket:



~\$14bn, or ~45%, of capex is expected to generate 2.0x PVI<sub>10</sub> or better

estimated total footage by asset area:



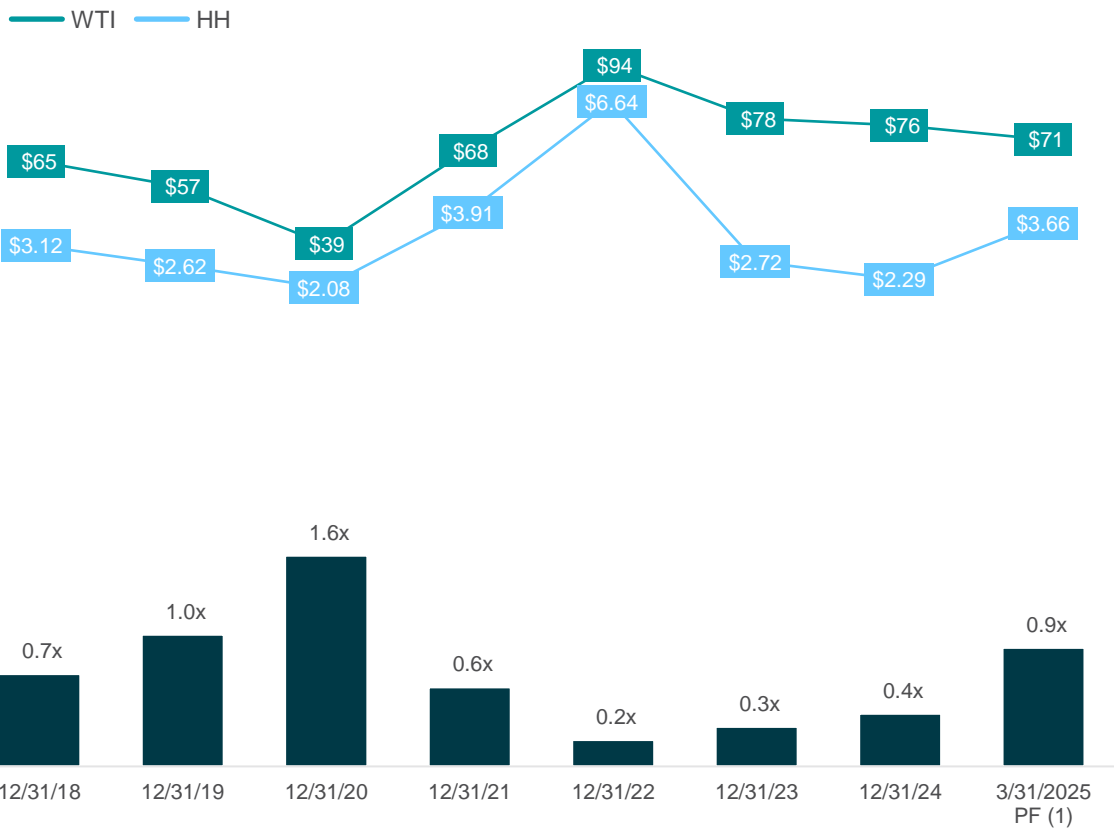
## Implied Inventory Duration<sup>1</sup>

estimates can fluctuate based on assumptions around well spacing, cost levels, commodity prices, & activity cadence

Permian	~15 years
Marcellus	~12 years
Anadarko	~15 years
Total company	~15 years

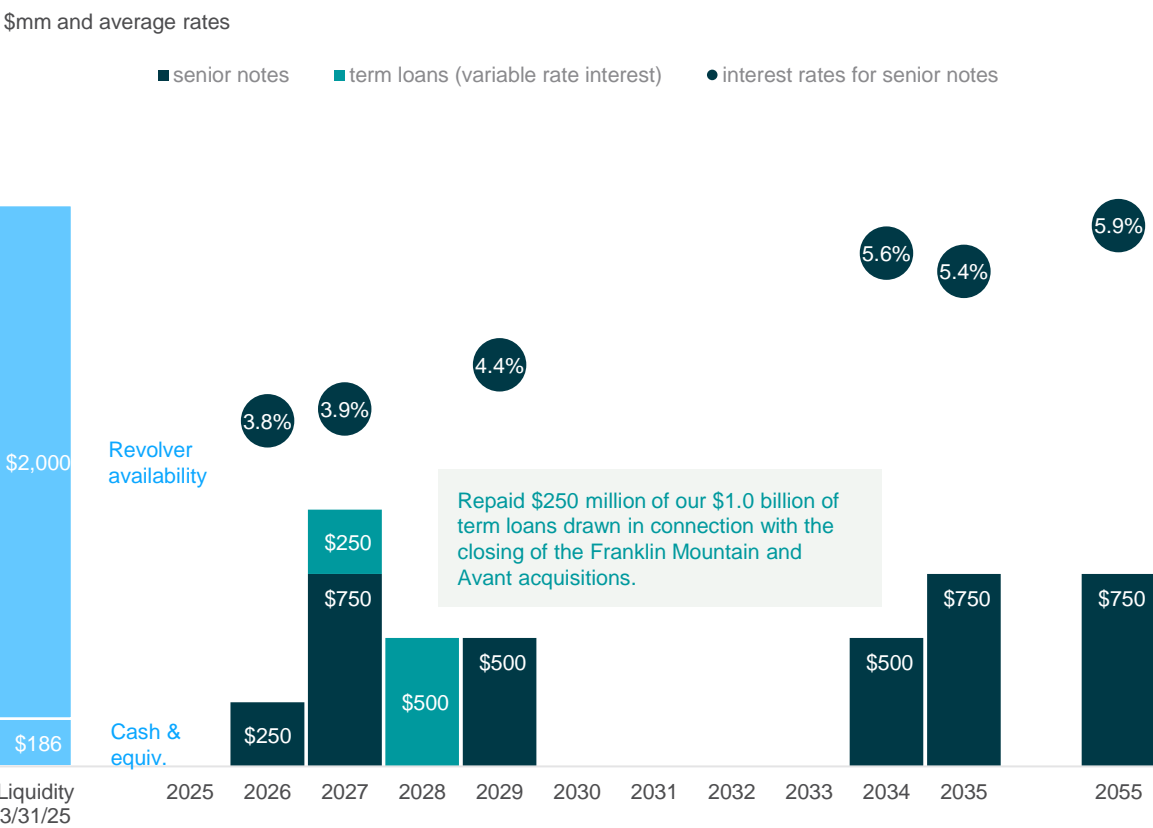
# Prioritizing Financial Flexibility

## History of Conservative Net Leverage



Target <1x Net Leverage for maximum flexibility through all price cycles

## Liquidity & Debt Maturity Profile



Conservative debt balance, low rates, & long-dated maturities with substantial liquidity



# Permian Asset Overview – 2025 Operational Outlook

**\$1,450 million**  
Midpoint D&C CapEx

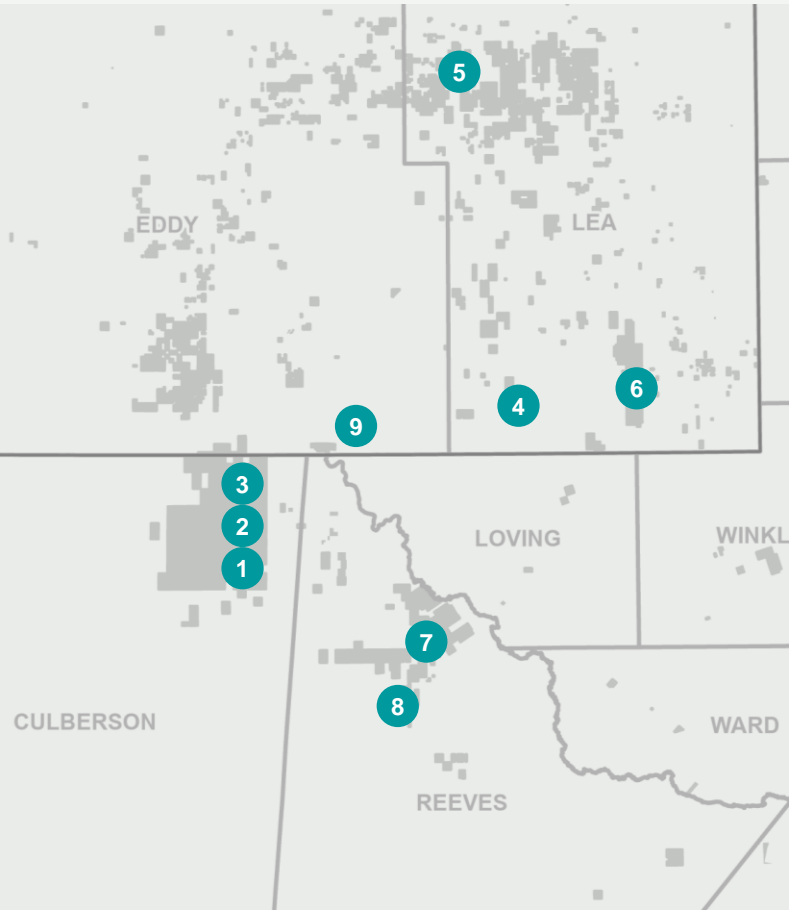
**10,600'**  
Avg. Lateral  
Length<sup>1</sup>

**\$960**  
Avg. Well Cost  
per Foot<sup>1</sup>

**150-165**  
Net Wells  
Online

# Permian Asset Overview

## Targeting Prolific Wolfcamp & Bone Spring



Coterra Acreage

## Notable Projects

### Culberson County, TX

#### 1. Windham Row Update

- 73 gross wells (50% WI), across six DSUs
- Capital:** D&C \$/ft of \$850
- One of the lowest-cost developments in our portfolio. Efficiency gains expected to be a tailwind for upcoming projects.

#### Wolfcamp: 51 gross / 26 net wells:

- Generating strong performance across all DSUs, with results above expectations

#### Harkey: 22 gross / 11 net wells

- Roughly half of Windham Harkey wells are producing anomalously high water volumes; performing wellbore cement remediation work, seeing encouraging early time remediation impact. While we work through remediation, we are pausing Harkey development in Eastern Culberson.
- The impact to our 2Q25 oil volumes is expected to be approximately -5 Mbopd. We are continuing Culberson Wolfcamp row development in 2025, which is expected to improve capital efficiency. There are no changes to Culberson turn-in-line well counts or capital in 2025.

#### 2. Bowler Row

- 48 gross wells (50% WI), first production begins 4Q25

#### 3. Barba-Row

- 28 gross wells (80% WI), first production begins 2Q25

### Lea County, NM

#### 4. Red Hills

- 10 gross wells (78% WI), first prod 3Q25

#### 5. Alpha Wolf

- 9 gross wells (60% WI), first prod 2Q25

#### 6. Forge/Land of Enchantment

- 16 gross wells (85% WI), first prod 2Q25

### Reeves County, TX

#### 7. Marmacinda

- 10 gross wells (92% WI), first prod 1Q25

#### 8. Castle

- 3 gross wells (100% WI), first prod 3Q25

### Eddy County, NM

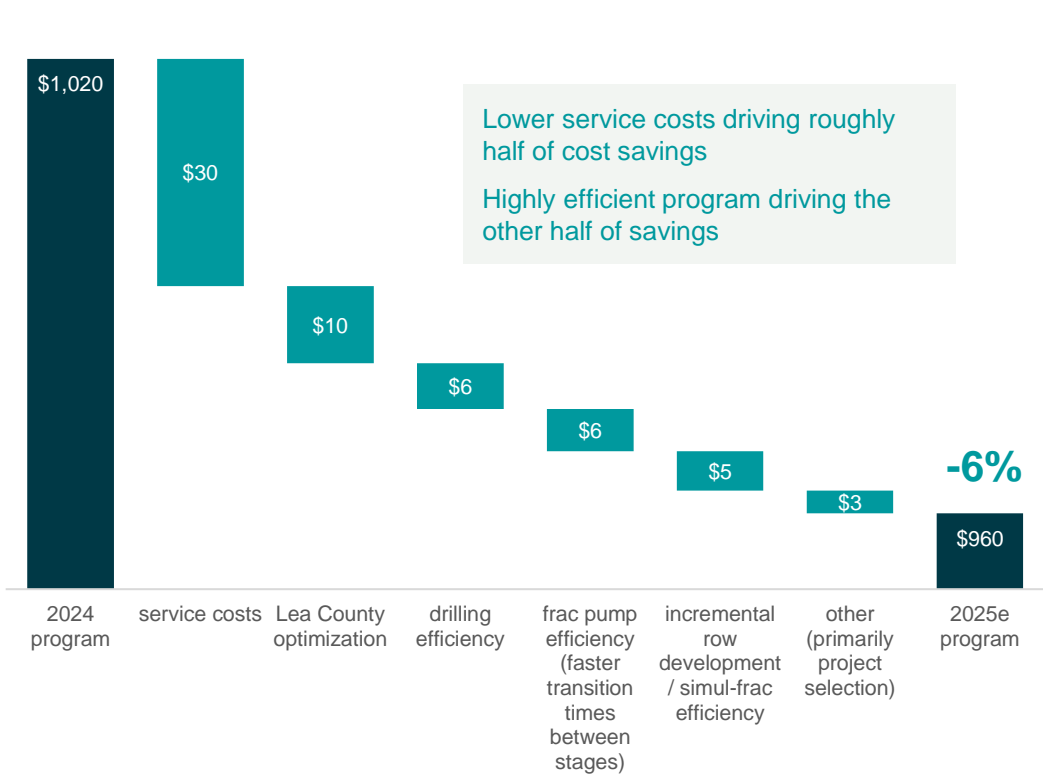
#### 9. Tar Heel

- 6 gross wells (100% WI), first prod 2Q25

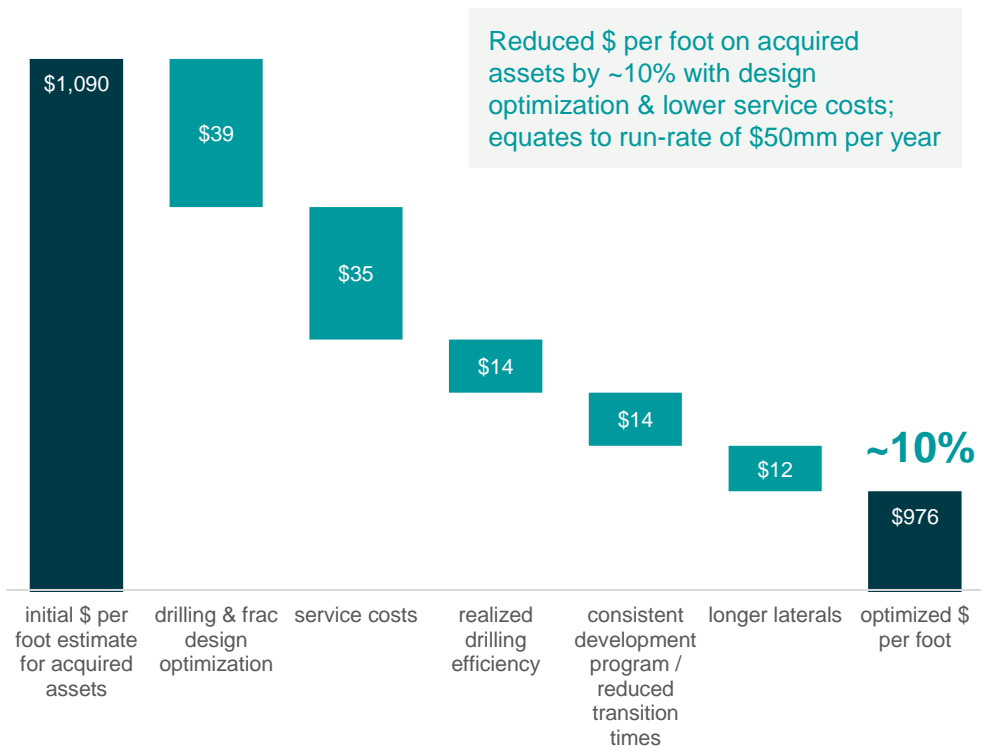
# Permian Well Cost Reductions Expected in 2025, Driven by Ops Efficiencies

\$ per foot cost estimates

Permian reduction driven by operational efficiencies



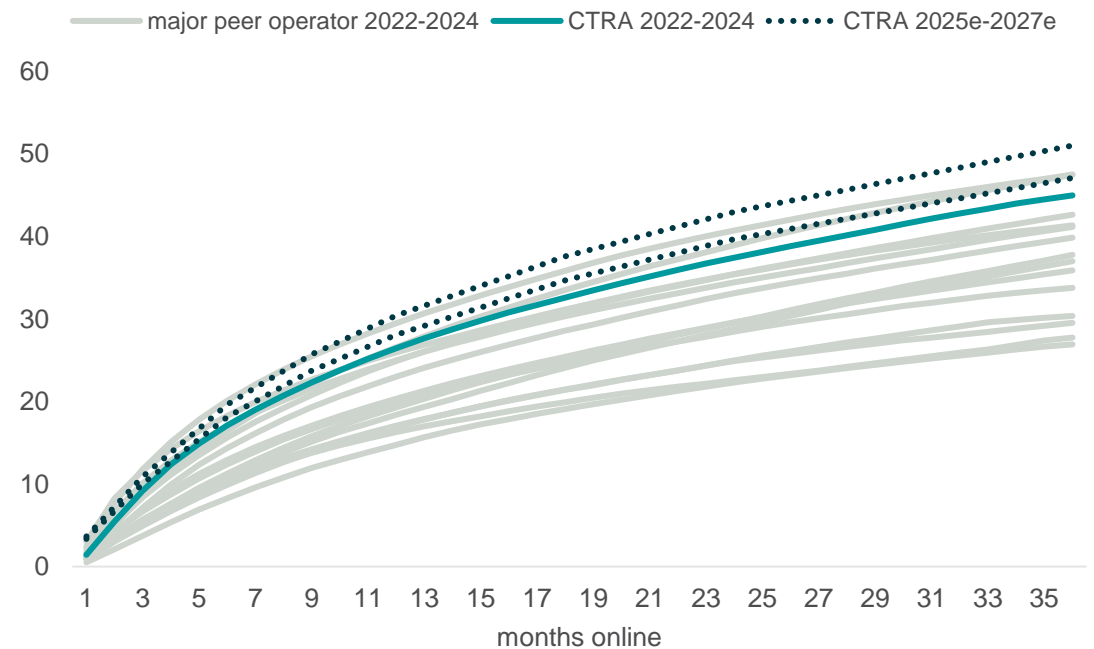
Synergies on our newly acquired Lea County asset



# Top-Tier Delaware Producer with Competitive D&C Well Costs

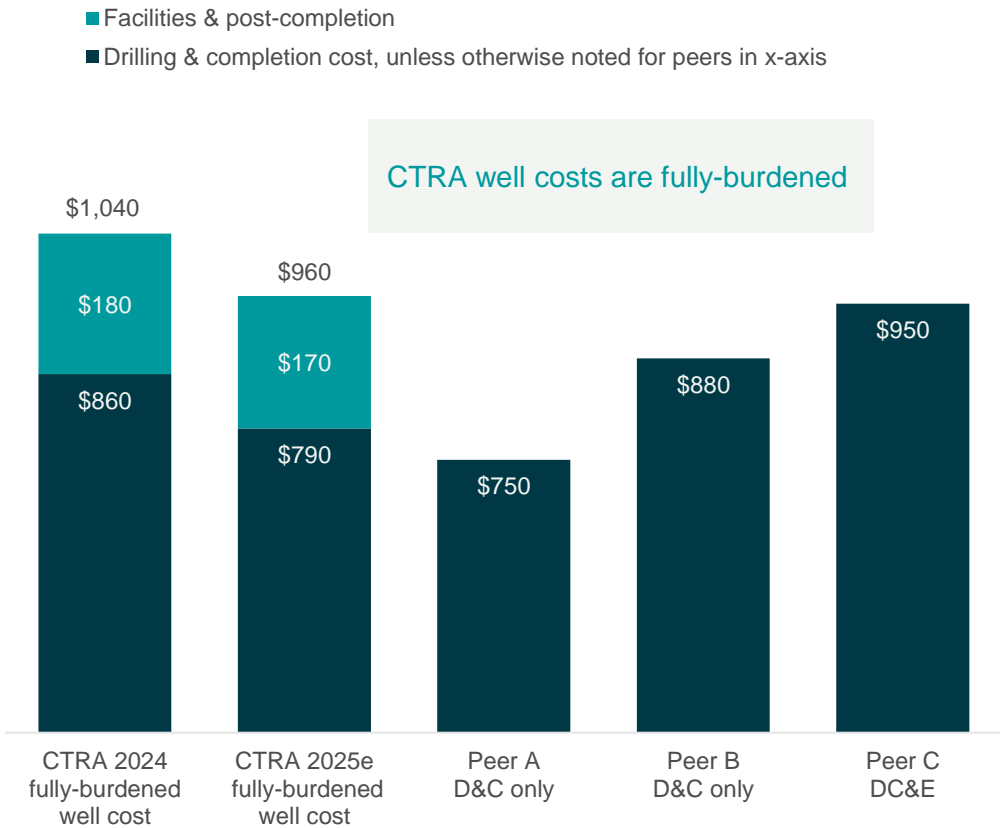
## Delaware Productivity<sup>1</sup>

cumulative 2-stream at 20:1 conversion ratio, boe per lateral foot



- Productivity will differ from year to year, depending on project selection & other operational decisions
- Generally, our Permian program will be ~1/2 Texas and ~1/2 New Mexico driven by our large, contiguous positions in Culberson County, Texas and Lea County, New Mexico
- Our program continues to benefit from optimized spacing and completion design decisions that generate resilient returns at various commodity prices

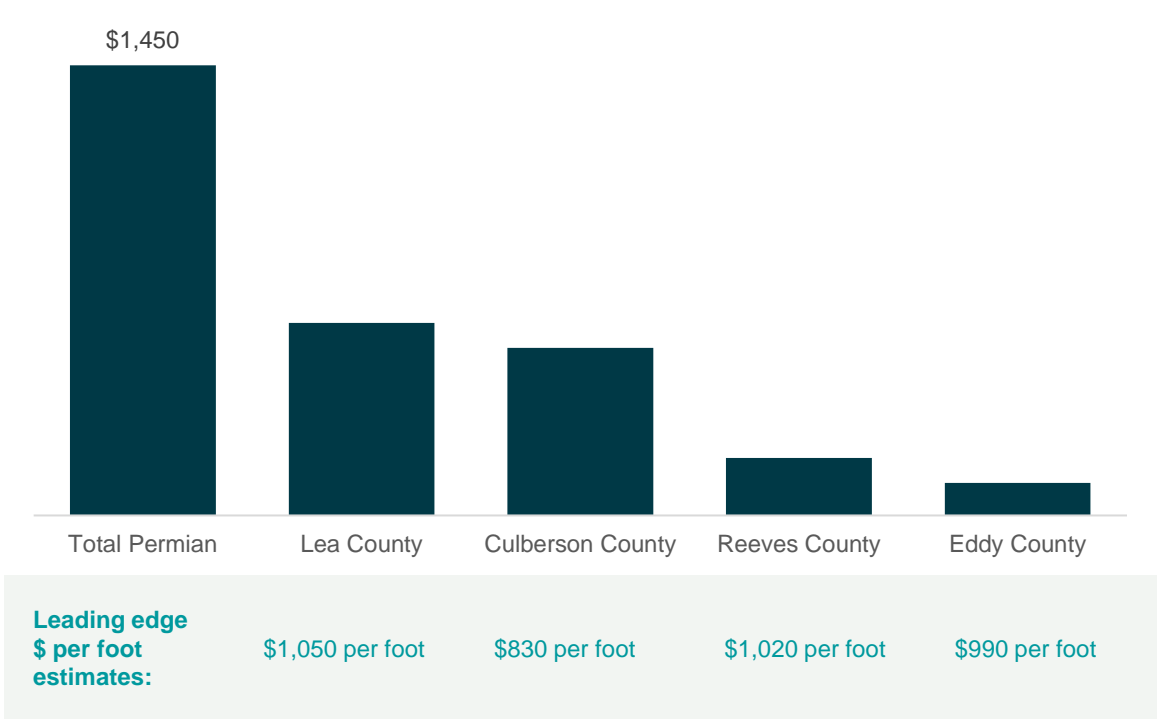
## Recent Delaware D&C Well Costs per Foot<sup>2</sup>





# 2025 Permian Development Program

2025e mid-point D&C capex in \$ millions



2025e net wells online



# Marcellus Asset Overview – 2025 Operational Outlook

**\$300 million**  
Midpoint D&C CapEx

**19,100'**

Avg. Lateral  
Length for Upper<sup>1</sup>

**\$660**

Avg. Well  
Cost per Foot<sup>1</sup>

**14,700'**

Avg. Lateral  
Length for Lower<sup>1</sup>

**\$860**

Avg. Well  
Cost per Foot<sup>1</sup>

**10-15**

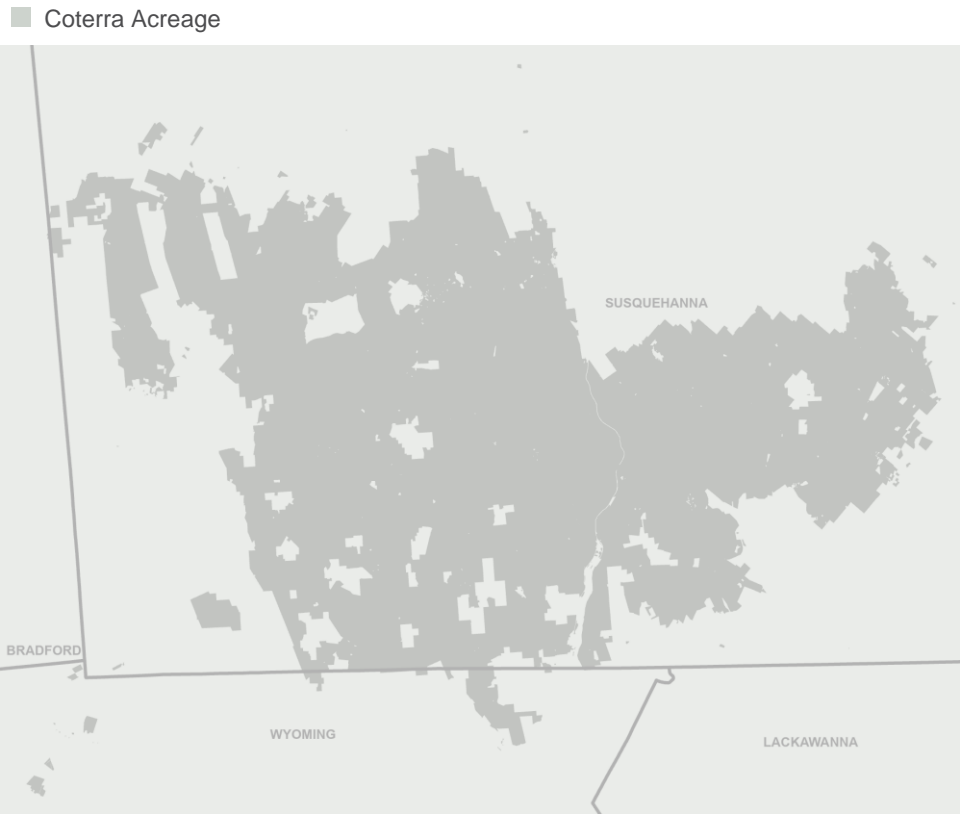
Net Wells  
Online

~30% Upper &  
~70% Lower

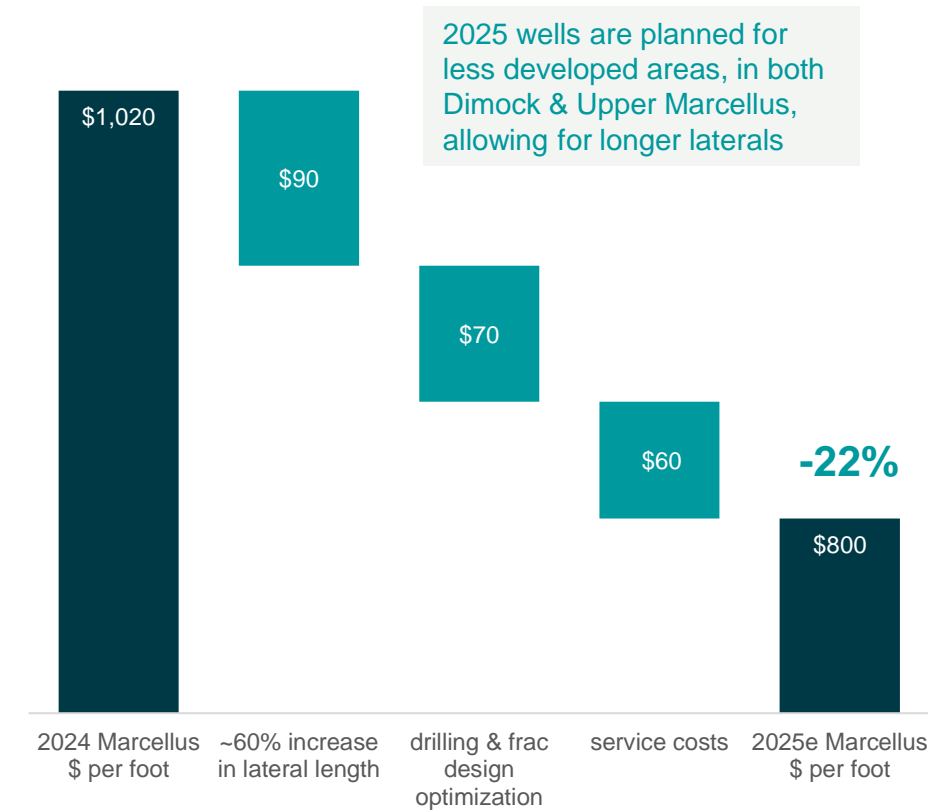
# Marcellus Asset Overview

Highly capital efficient: ~\$450mm annual capex spend maintains ~2 bcfd production levels

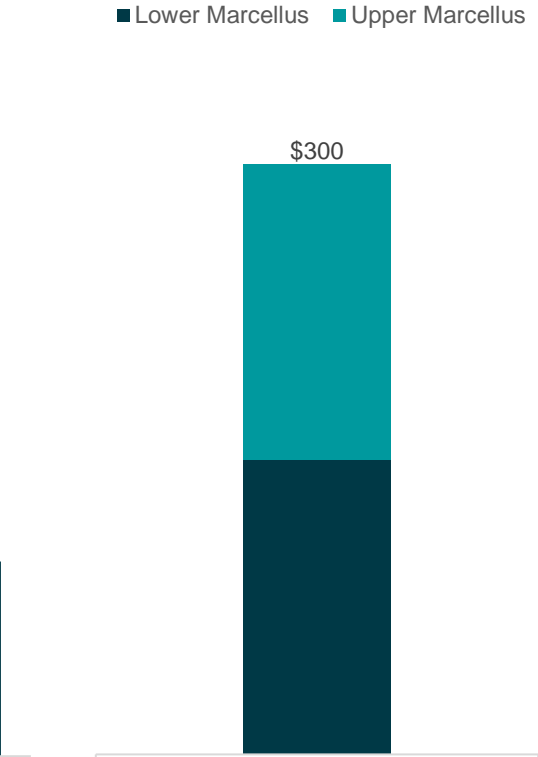
## Susquehanna County acreage leverages highly productive Marcellus



## Reduction in well costs YoY driven by significantly longer laterals



## 2025e mid-point D&C capex in \$ millions



# Anadarko Asset Overview – 2025 Operational Outlook

**\$230 million**  
Midpoint D&C CapEx

**11,080'**  
Avg. Lateral  
Length<sup>1</sup>

**\$1,070**  
Avg. Well Cost  
per Foot<sup>1</sup>

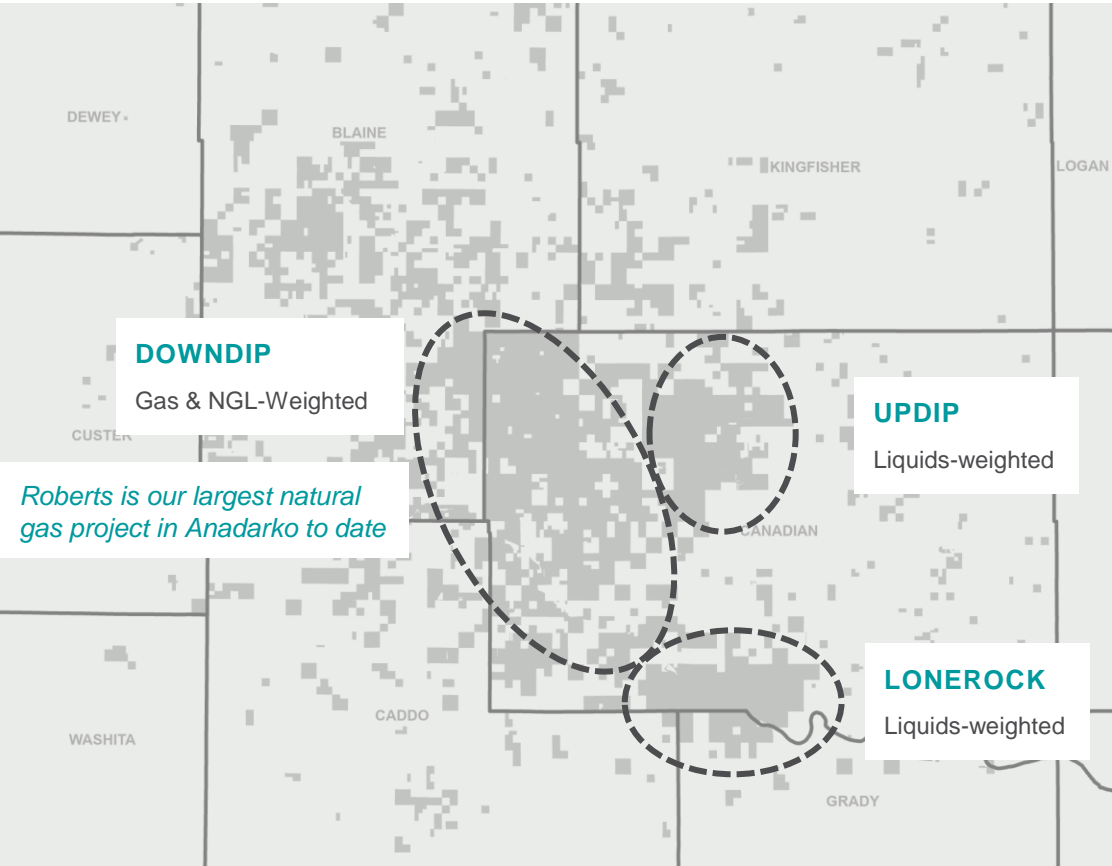
**15-25**  
Net Wells  
Online

1) Based on 2025e operated, completed wells. Note: Spend for a well is incurred over a period of 6-10 months, which does not necessarily fall within a single calendar year. \$ per foot includes drilling, completion, facilities and post-completion capital



# Anadarko Asset Overview

## Anadarko sub-regions



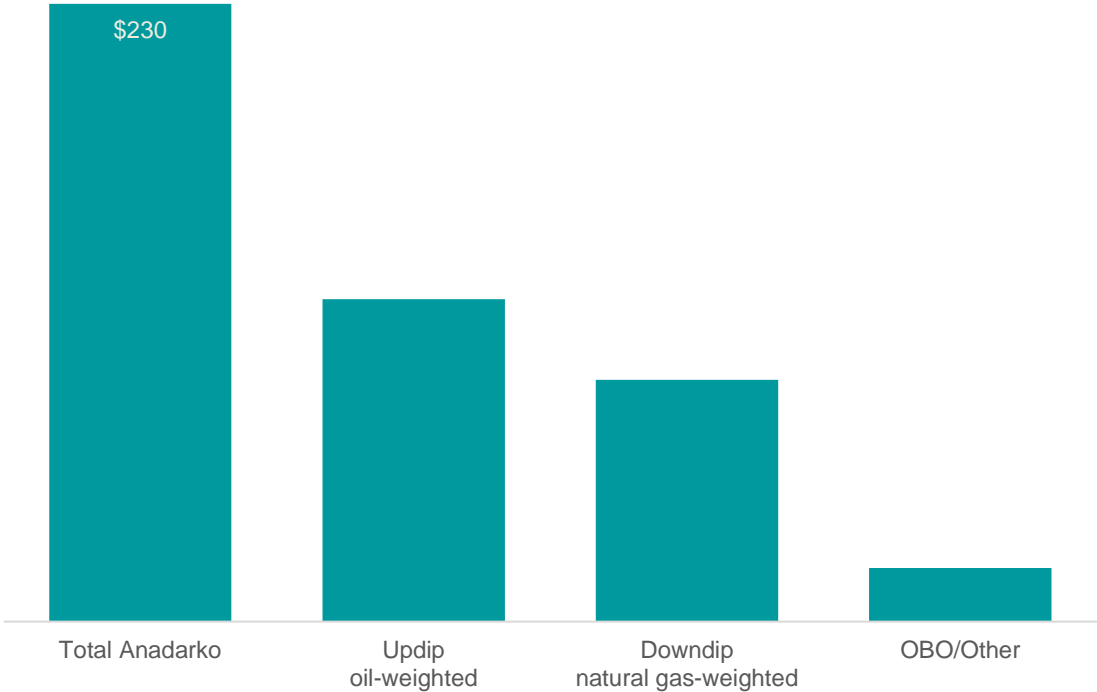
## Major 2025 Anadarko projects

Online	Project name	Well count	Area	Estimated 60-month production mix at 6:1						
2Q 2025	Roberts	8.9 net (9 gross)	Downdip (Primarily Woodford, 1 gross Meramec)	<table><tr><td>oil</td><td>3%</td></tr><tr><td>NGL</td><td>40%</td></tr><tr><td>gas</td><td>57%</td></tr></table>	oil	3%	NGL	40%	gas	57%
oil	3%									
NGL	40%									
gas	57%									
3Q 2025	Hufnagel	4.4 net (6 gross)	Updip (Primarily Woodford, 2 gross Meramec)	<table><tr><td>oil</td><td>28%</td></tr><tr><td>NGL</td><td>30%</td></tr><tr><td>gas</td><td>43%</td></tr></table>	oil	28%	NGL	30%	gas	43%
oil	28%									
NGL	30%									
gas	43%									
3Q 2025	Clark	5.6 net (6 gross)	Updip (Primarily Woodford, 2 gross Meramec)	<table><tr><td>oil</td><td>25%</td></tr><tr><td>NGL</td><td>31%</td></tr><tr><td>gas</td><td>44%</td></tr></table>	oil	25%	NGL	31%	gas	44%
oil	25%									
NGL	31%									
gas	44%									

# Anadarko Investment Allocation by Area & Cost Savings

Wider spacing, longer laterals, and lower well costs are driving improved productivity & higher returns

2025e mid-point D&C capex in \$ millions



YoY cost savings driven by longer laterals<sup>1</sup>





# Appendix





# High-Quality, Long-Life, Diversified Asset Portfolio

## Multi-Basin Portfolio

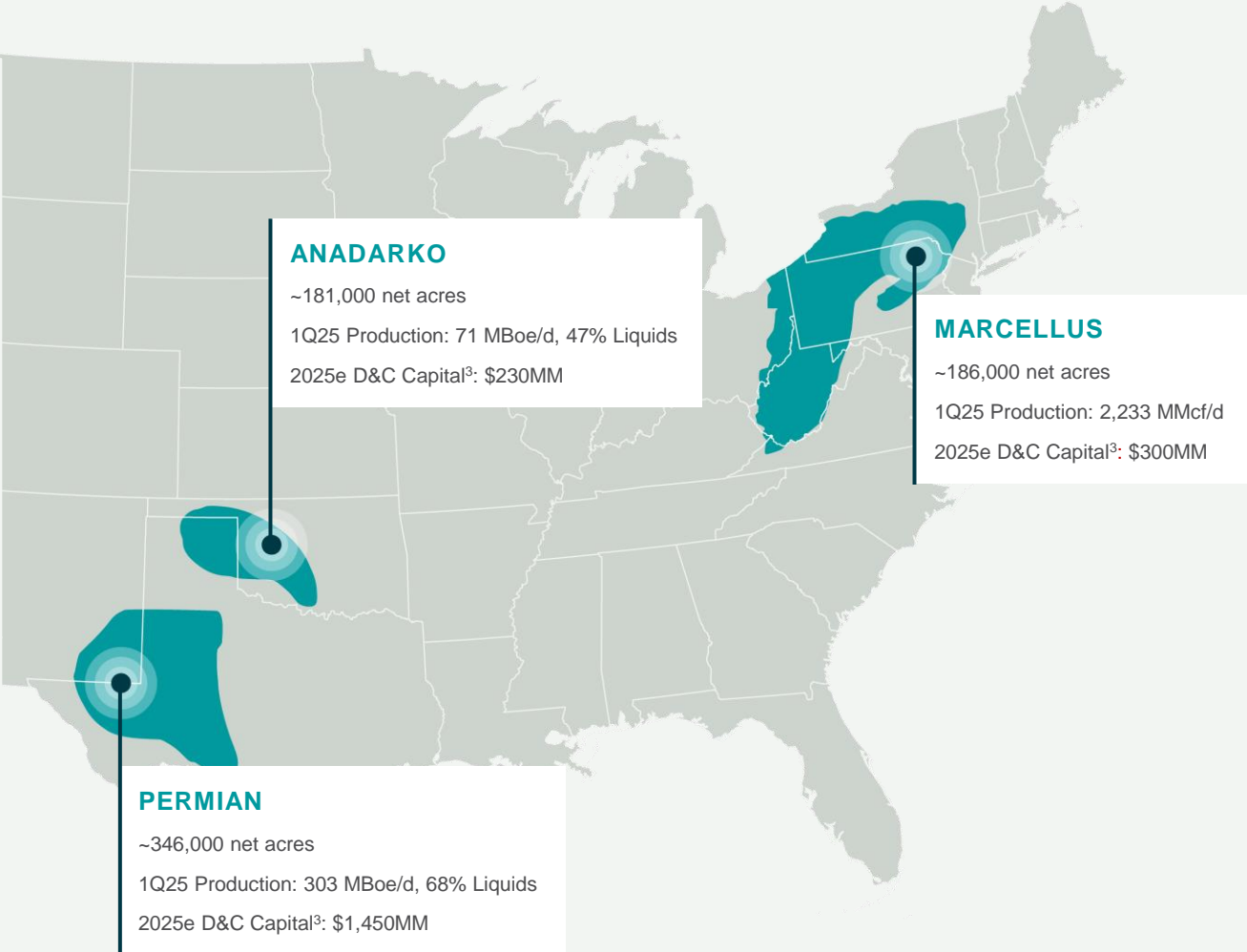
provides commodity diversification and capital allocation optionality

## Top-Tier Acreage Position

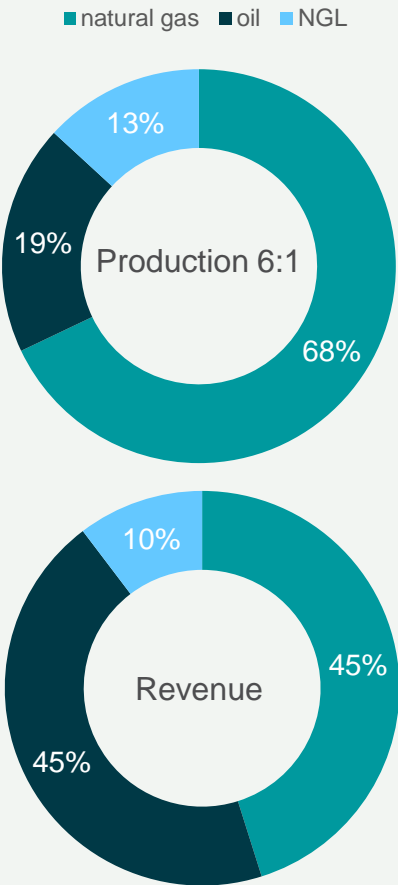
with deep inventory, estimated at ~15 years<sup>1</sup>

## Low-Cost Operator

with corporate break-even<sup>2</sup> around \$50/bbl WTI & \$2.50/mmbtu HH



## 1Q25 Commodity Splits





# Executive Compensation Tied to Emissions Reduction Metrics

20% of total short-term incentive potential

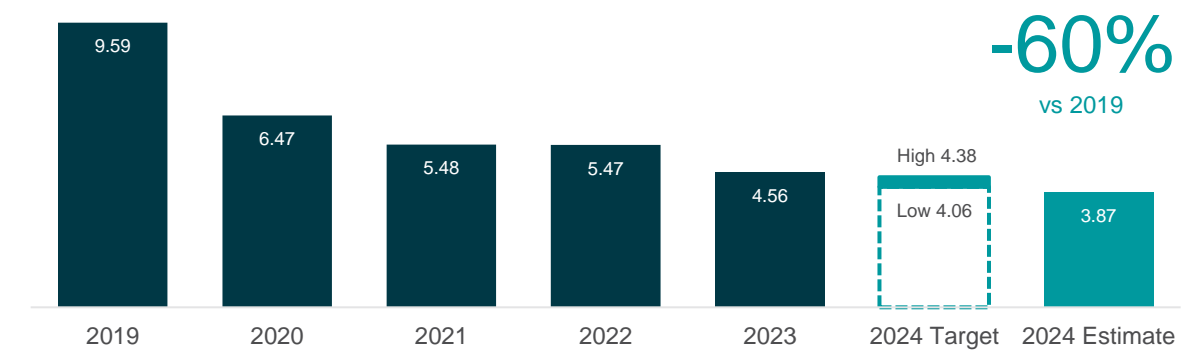
## Climate Targets

In 2024, four climate metrics were included in Coterra’s executive short-term incentive targets. These four targets constitute 20% of the overall executive short-term incentives:

Metric	Midpoint of Target	2024 Estimates
GHG Intensity (MT CO <sub>2</sub> e/Gross Mboe Produced)	4.22	3.84
Methane Intensity (MT CH <sub>4</sub> , Emitted / Gross MT CH <sub>4</sub> , Produced)	0.016%	0.014%
Flared Intensity (Volume of Gas Flared / Volume of Gas Produced)	0.077%	0.049%
Flyover Finding Goal (Average Findings / Flight)	11.55	6.0

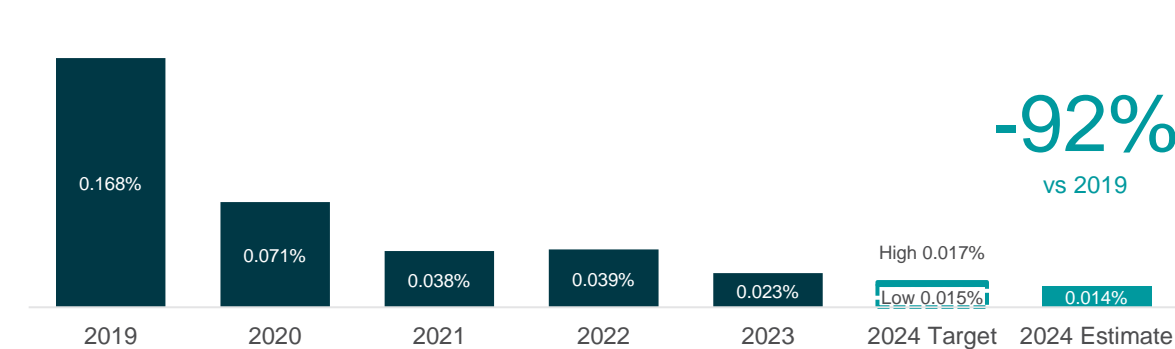
## Greenhouse Gas Emissions Intensity

MT CO<sub>2</sub>e / Gross Mboe Produced



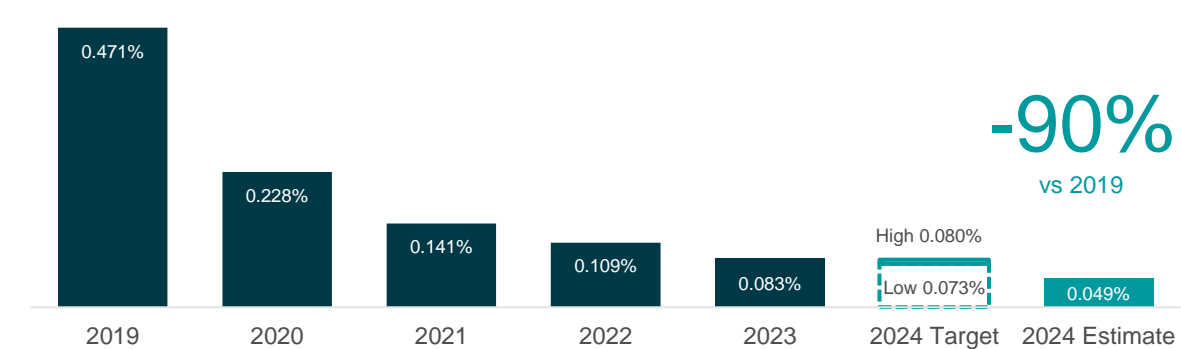
## Methane Emissions Intensity

MT CH<sub>4</sub> Emitted / Gross MT CH<sub>4</sub> Produced



## Total Company Flare Intensity

Volume of Gas Flared / Volume of Gas Produced



# Emissions Reductions Efforts



## Greenhouse Gas Emissions

- Electrifying compressors, fracs, & drilling rigs typically reduces net Scope 1 + Scope 2 emissions from those sources by 25-45%, depending on the technology being electrified
- Exited 2023 with 16 midstream electric compressors (up from 4 in 2022) in service and expect to install 6 more in 2024; 22 total compressors have the potential to save >400,000 metric tons CO2e Scope 1 emissions per year
- Exited 2023 with ~30% of our midstream compression electrified



## Flared Emissions

- Utilizing Vapor Recovery Units to maximize revenue and minimize flaring
- Centralizing flares to compressor stations, rather than individual pad sites
- Exited 2023 with 9 centralized flares (up from 2 in 2022), which eliminated >130 high-pressure flare sources from our production facilities
- Zero routine high-pressure flaring



## Methane Emissions

- Eliminating natural gas pneumatic devices
- Installing equipment (tubing, artificial lift, well-site compression) to reduce need for liquid unloading events
- Performing voluntary leak-detection inspections, beyond regulatory requirements
- Evaluating continuous methane monitoring technology



## Fugitive Emissions

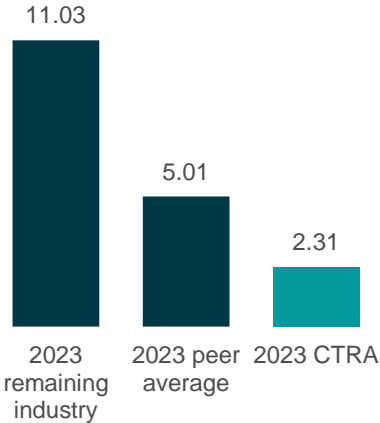
- Performing aerial methane detection campaigns across our operating areas
- Added new metric in 2024, Findings / Flight, tied to executive compensation

# Upstream Greenhouse Gas Intensity vs. Peers & Industry

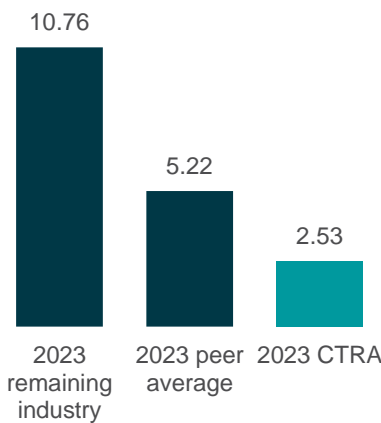
GHG Intensity (MT CO2e / Gross Mboe)

We analyze our upstream emissions on a standalone basis to compare our performance against our peers<sup>1</sup>, as our peer group has varying levels of operations within the upstream and midstream segments. The following data is derived from EPA Subpart W-submitted data:

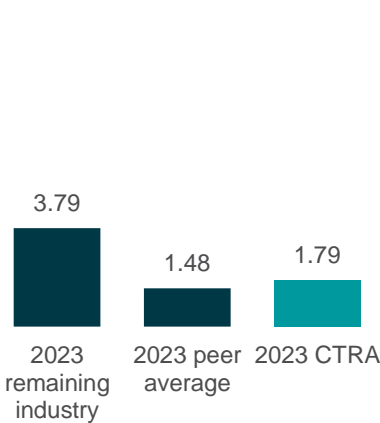
## All U.S. basins



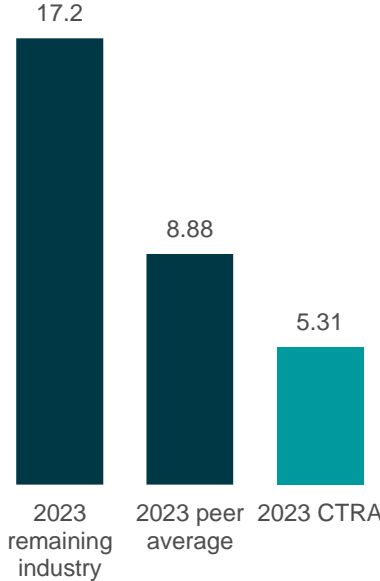
## Permian



## Marcellus



## Anadarko



1) Compensation peer group is comprised of AR, APA, DVN, EXE, FANG, EOG, EQT, HES, MRO, OXY, OVV, and PXD.



# Diversifying Gas Portfolio with New LNG Contracts

Reducing in-basin price exposure & diversifying toward European and Asian markets with expanding LNG portfolio

Contracted LNG Volumes	Production From	Pricing Index
50 mmcf	Marcellus	TTF
2028 – 2038 LNG terminal in Louisiana <sup>1</sup> Counterparty is Centrica, utility in U.K. & Ireland		
50 mmcf	Anadarko	NBP
2028 – 2038 LNG terminal in Louisiana <sup>1</sup> Counterparty is Centrica, utility in U.K. & Ireland		
100 mmcf	Permian	JKM
2027 – 2038 LNG terminal in Louisiana <sup>1</sup> Counterparty is Vitol		
350 mmcf	Marcellus	NYMEX
2018 – 2038 (existing LNG contract) Cove Point LNG Terminal in Maryland Counterparty is Pacific Summit Energy, serves Japanese power gen customers		

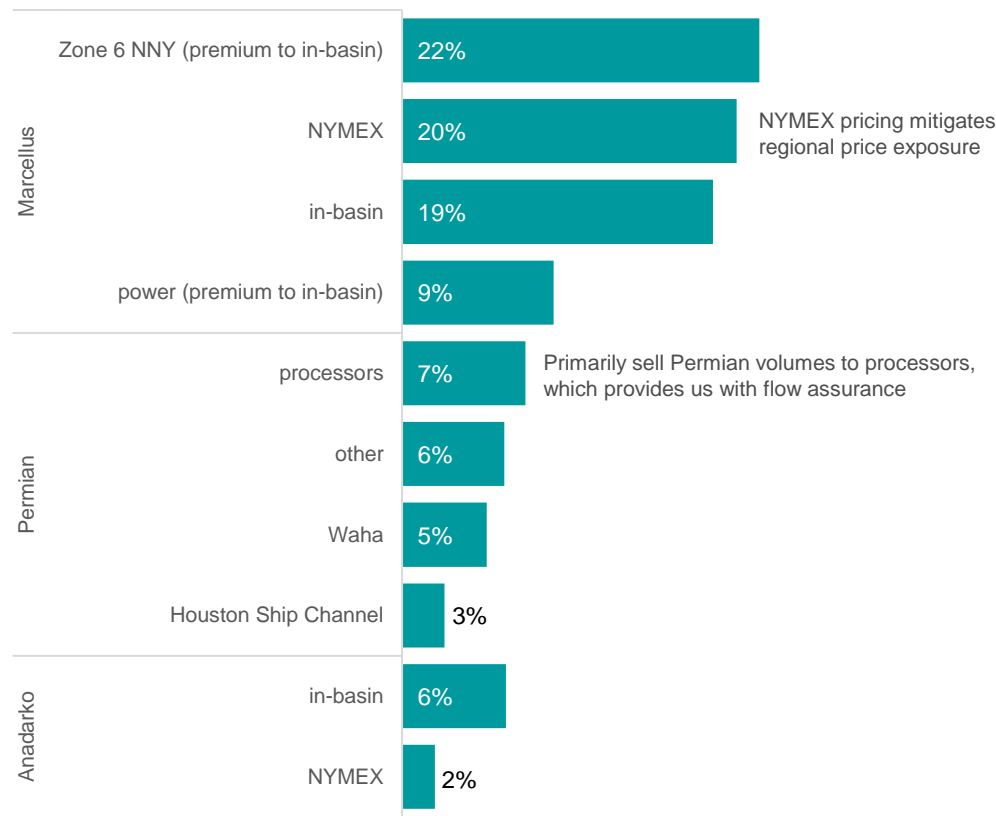


# Midstream/Power Capability in our Permian Assets

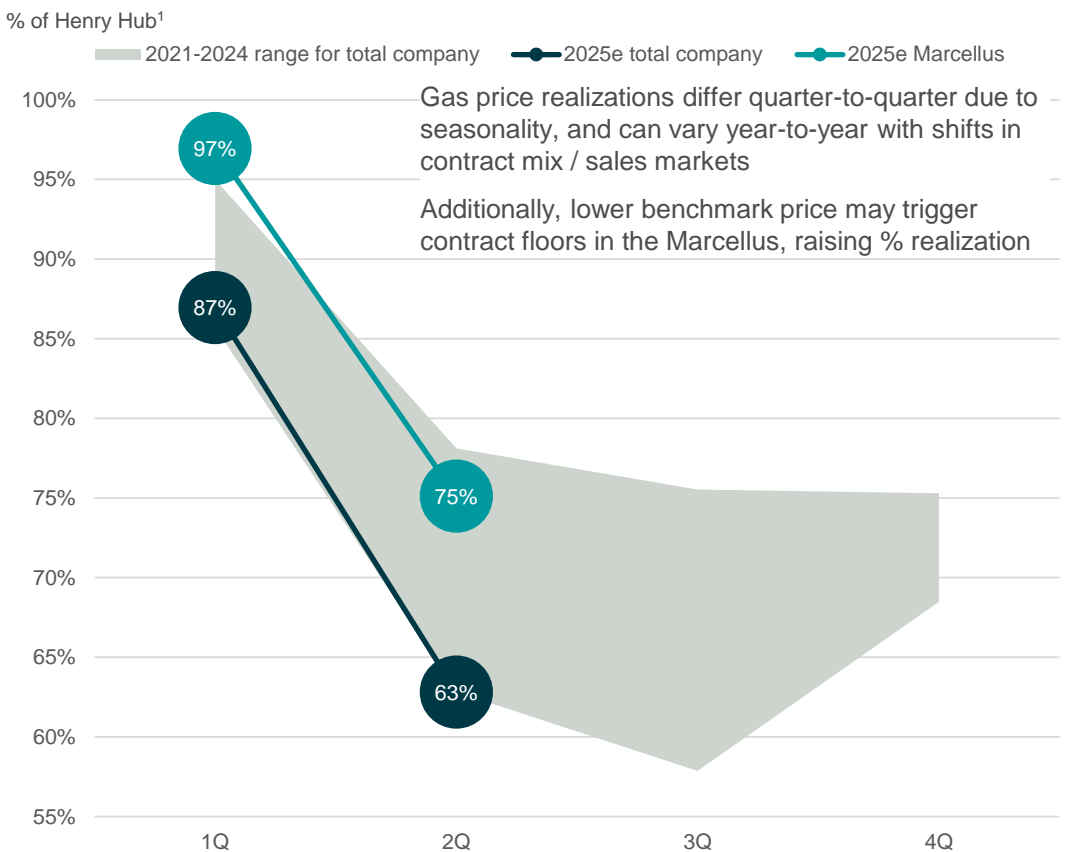
	 Culberson and Reeves Counties	 Lea County Bolt-on Acquisition	Cost Savings
<b>Saltwater Disposal</b> <i>Allows for substantial recycling of produced water back into our completion operations</i>	<ul style="list-style-type: none"><li>• Over 300 miles of pipeline, reduces surface storage &amp; potential spills</li><li>• In 2024, Coterra's Permian completions used 89% recycled water, up 3% from the previous year, facilitated by our SWD assets</li></ul>	<ul style="list-style-type: none"><li>• ~120 miles of pipeline</li><li>• Expect to recycle ~50% of water on acquired assets in 2025 (previously forecasted at ~40%)</li></ul>	<b>30-60% per barrel cost savings</b> <i>vs. using third-party water</i>
<b>Electric Grid</b> <i>Plugging directly into ERCOT, rather than relying on diesel- or natural gas-powered generators, provides significant cost savings</i>	<ul style="list-style-type: none"><li>• &gt;200 miles of electrical distribution powerlines</li><li>• 3 substations with total capacity of 260 MW</li><li>• Fully powers e-compression (70 MW), full-time e-fleet in Culberson (33 MW), wells &amp; facilities (30 MW), and 3-4 e-rigs (3 MW)</li></ul>	<ul style="list-style-type: none"><li>• Investigating power grid opportunities for future years</li><li>• Using natural gas power generation while we wait on grid availability</li></ul>	<b>~\$50/ft</b> <i>e-frac vs. using diesel, @ recent spark spread</i>
<b>Gas Gathering System</b> <i>Brings expenses in-house, enhances netbacks and economics</i>	<ul style="list-style-type: none"><li>• Over 600 miles of pipeline</li><li>• Throughput capacity &gt; 1.2 Bcfd</li><li>• Takeaway supported by 20 offload points &amp; offers competitive pricing</li></ul>	<ul style="list-style-type: none"><li>• ~125 miles of pipeline</li><li>• Throughput capacity ~130 mmcf/d</li></ul>	

# Diversified Gas Marketing Portfolio

## 2025 Estimated Natural Gas Sales Markets



## 2021-2025e Natural Gas Price Realization Range<sup>1</sup>

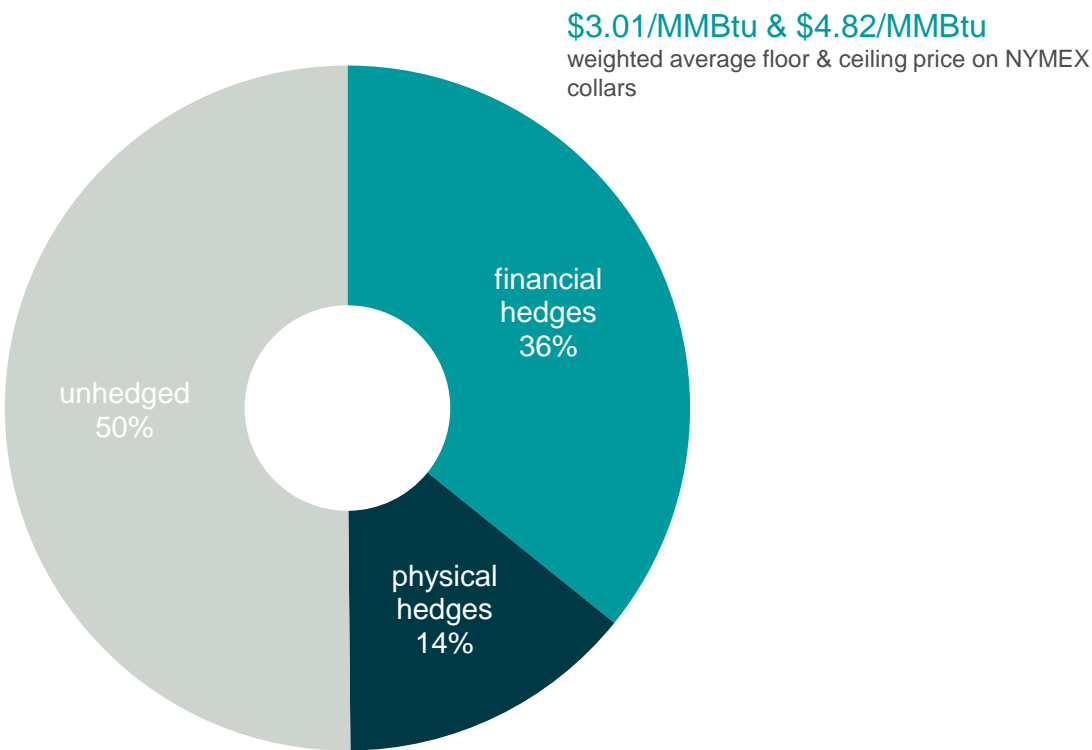




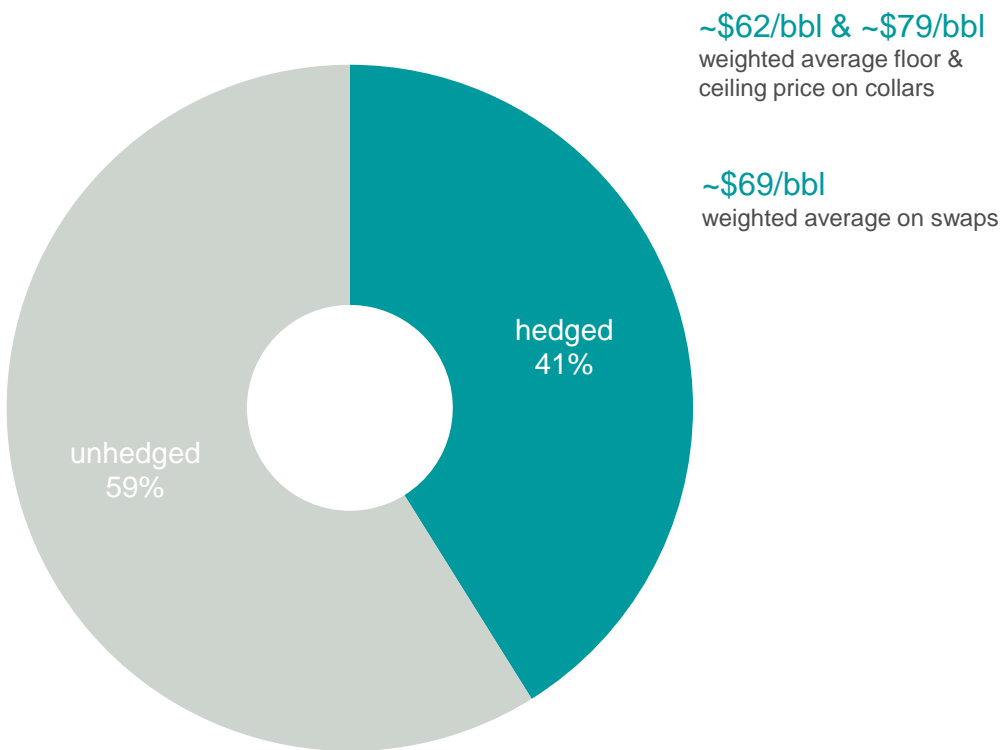
# 2025 Hedge Summary

2Q25e-4Q25e

## Remaining 2025e gas volumes ~50% hedged



## Remaining 2025e oil volumes >40% hedged

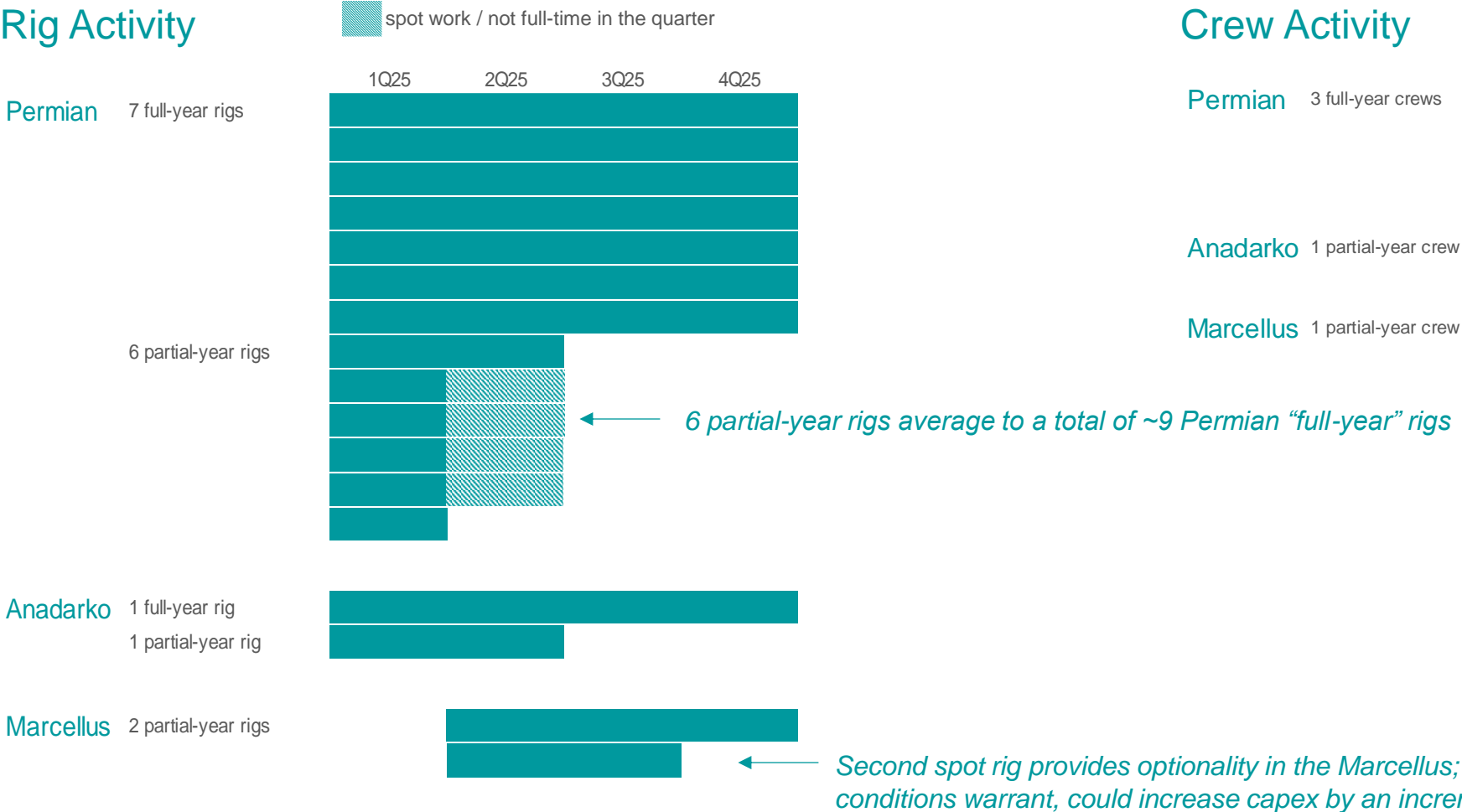


# Guidance & Actuals

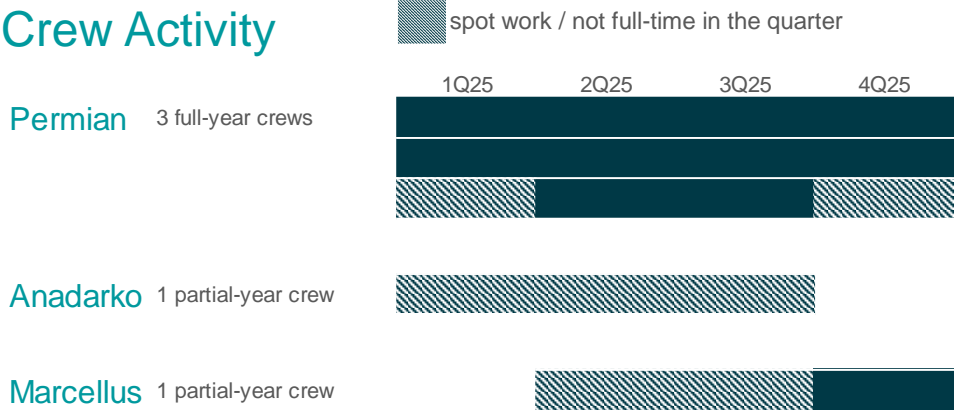
		2025 Guidance (February)			Updated 2025 Guidance			1Q25 Guidance			1Q25 Actual	2Q25 Guidance		
		Low	Mid	High	Low	Mid	High	Low	Mid	High		Low	Mid	High
Operations	Total Production (mboed)	710	- 740	- 770	720	- 745	- 770	710	- 730	- 750	747	710	- 735	- 760
	Gas (mmcf/d)	2,675	- 2,775	- 2,875	2,725	- 2,800	- 2,875	2,850	- 2,925	- 3,000	3,044	2,700	- 2,775	- 2,850
	Oil (mbod)	152.0	- 160.0	- 168.0	155.0	- 160.0	- 165.0	134.0	- 139.0	- 144.0	141.2	147.0	- 152.0	- 157.0
	Net wells online													
	Marcellus	10	- 13	- 15		No change			0		0		3	
	Permian	150	- 158	- 165		No change		35	- 40	- 45	37	45	- 55	- 65
	Anadarko	15	- 20	- 25		No change			0		0		9	
	\$ millions:													
	Incurred Capital Expenditures	\$2,100	- \$2,250	- \$2,400	\$2,000	- \$2,150	- \$2,300	\$525	- \$575	- \$625	\$552	\$575	- \$613	- \$650
	Marcellus D&C		\$250	midpoint		\$300	midpoint				\$8			
Cash Flow & Investment	Permian D&C		\$1,570	midpoint		\$1,450	midpoint				\$433			
	Anadarko D&C		\$230	midpoint		No change					\$69			
	Midstream, saltwater disposal, infrastructure		\$200	midpoint		\$170	midpoint				\$42			
	Commodity price assumptions:													
	WTI (\$ per bbl)		\$71			\$63								
	Henry Hub (\$ per mmbtu)		\$4.22			\$3.72								
	\$ billions:													
	Discretionary Cash Flow		\$5.0			\$4.3								
	Incurred Capital Expenditures	\$2.1	- \$2.3	- \$2.4	\$2.0	- \$2.2	- \$2.3							
	GAAP Cash paid for capital expenditures for drilling, completion, and other fixed asset additions													
	Free Cash Flow (DCF - cash capex)		\$2.7			\$2.1								

# Expected 2025 Operational Cadence

## Rig Activity



## Crew Activity



# Expense Guidance & Actuals

Expense guidance provided for annual 2025

		2024 Actual	2025 Guidance			1Q25 Actual
Expense	\$ per boe, unless noted:					
	Lease operating expense + workovers + region office	\$2.66	\$2.50	- \$3.05	- \$3.60	\$3.21
	Gathering, processing, & transportation	\$3.94	\$3.25	- \$3.75	- \$4.25	\$4.20
	Taxes other than income	\$1.09	\$1.25	- \$1.50	- \$1.75	\$1.43
	General & administrative <sup>1</sup>	\$0.97	\$0.90	- \$1.00	- \$1.10	\$1.12
	Unit Operating Cost	\$8.66	\$7.90	- \$9.30	- \$10.70	\$9.96
	DD&A	\$7.43	\$8.00	- \$8.75	- \$9.50	\$7.53
	Exploration <sup>2</sup>	\$0.10	\$0.05	- \$0.08	- \$0.10	\$0.15
	% effective tax rate					
	% cash tax rate <sup>3</sup>	27%	20% - 25%			20%

1 Excludes stock-based compensation, merger-related expenses, and severance expense

2 Excluding exploratory dry hole costs, includes exploration administrative expense and geophysical expenses

3 Based on changes to Sec 174 tax treatment of R&D expenditures, we expect FY25 cash tax rate (current tax / pre-tax income) to be approximately 20-25%. Over time, we expect this cash tax rate estimate to decrease as the effects of the R&D amortization versus previous expensing minimizes.

# Non-GAAP Reconciliations & Definitions

**Supplemental Non-GAAP Financial Measures (Unaudited):** We report our financial results in accordance with accounting principles generally accepted in the United States (GAAP). However, we believe certain non-GAAP performance measures may provide financial statement users with additional meaningful comparisons between current results and results of prior periods. In addition, we believe these measures are used by analysts and others in the valuation, rating and investment recommendations of companies within the oil and natural gas exploration and production industry. See the reconciliations below that compare GAAP financial measures to non-GAAP financial measures for the periods indicated.

We have also included herein certain forward-looking non-GAAP financial measures including, among others, the reinvestment rate, which is defined as capital expenditures (non-GAAP) as a percentage of Discretionary Cash Flow (non-GAAP). We believe the reinvestment rate provides investors with useful information on management's projected use and reinvestment of its future cash flows back in Coterra's operations. Due to the forward-looking nature of these non-GAAP financial measures, we cannot reliably predict certain of the necessary components of the most directly comparable forward-looking GAAP measures, such as changes in assets and liabilities (including future impairments) and cash paid for capital expenditures. Accordingly, we are unable to present a quantitative reconciliation of such forward-looking non-GAAP financial measures to their most directly comparable forward-looking GAAP financial measures. Reconciling items in future periods could be significant.

Capital expenditures is defined as cash capital expenditures for drilling, completion and other fixed asset additions less changes in accrued capital costs.

Discretionary Cash Flow is defined as cash flow from operating activities excluding changes in assets and liabilities. Discretionary Cash Flow is widely accepted as a financial indicator of an oil and gas company's ability to generate available cash to internally fund exploration and development activities, return capital to shareholders through dividends and share repurchases, and service debt and is used by our management for that purpose. Discretionary Cash Flow is presented based on our management's belief that this non-GAAP measure is useful information to investors when comparing our cash flows with the cash flows of other companies that use the full cost method of accounting for oil and gas produced activities or have different financing and capital structures or tax rates. Discretionary Cash Flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating activities or net income, as defined by GAAP, or as a measure of liquidity.

Free Cash Flow is defined as Discretionary Cash Flow less cash paid for capital expenditures. Free Cash Flow is an indicator of a company's ability to generate cash flow after spending the money required to maintain or expand its asset base and is used by our management for that purpose. Free Cash Flow is presented based on our management's belief that this non-GAAP measure is useful information to investors when comparing our cash flows with the cash flows of other companies. Free Cash Flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flow from operating activities or net income, as defined by GAAP, or as a measure of liquidity.

Three Months Ended:	31-Mar
(\$ in millions)	2025
<b>Cash flow from operating activities</b>	\$ 1,144
Changes in assets and liabilities	(9)
<b>Discretionary cash flow</b>	<b>1,135</b>
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(472)
<b>Free cash flow</b>	<b>\$ 663</b>

Three Months Ended:	31-Mar
(\$ in millions)	2025
Cash capital expenditures for drilling, completion and other fixed asset additions	\$472
Change in accrued capital costs	80
Exploratory dry-hole cost	-
<b>Capital expenditures</b>	<b>\$552</b>

Twelve Months Ended:	Dec 31	Dec 31
(\$ in millions)	2023	2024
<b>Cash flow from operating activities</b>	\$ 3,658	\$ 2,795
Changes in assets and liabilities	(237)	173
<b>Discretionary cash flow</b>	<b>3,421</b>	<b>2,968</b>
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(2,089)	(1,754)
<b>Free cash flow</b>	<b>\$ 1,332</b>	<b>\$ 1,214</b>

Twelve Months Ended:	Dec 31	Dec 31
(\$ in millions)	2023	2024
Cash capital expenditures for drilling, completion and other fixed asset additions	\$2,089	\$1,754
Change in accrued capital costs	15	8
<b>Capital expenditures</b>	<b>\$2,104</b>	<b>\$1,762</b>

# Non-GAAP Reconciliations & Definitions

## EBITDAX

EBITDAX is defined as net income plus interest expense, other expense, income tax expense and benefit, depreciation, depletion, and amortization (including impairments), exploration expense, gain and loss on sale of assets, non-cash gain and loss on derivative instruments, earnings and loss on equity method investments, equity method investment distributions, stock-based compensation expense and merger-related costs. EBITDAX is presented on our management's belief that this non-GAAP measure is useful information to investors when evaluating our ability to internally fund exploration and development activities and to service or incur debt without regard to financial or capital structure. Our management uses EBITDAX for that purpose. EBITDAX is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating activities or net income, as defined by GAAP, or as a measure of liquidity.

The Combined EBITDAX calculations below reflect legacy Cabot and Cimarex results through September 30, 2021 and Coterra results thereafter. Legacy Cimarex operated under the full cost accounting method, unlike legacy Cabot, now Coterra, which operates under the successful efforts accounting method. This difference in accounting methodologies leads to differences in the calculation of company financials and the figures below should not be relied on to predict future performance of the combined business, which operates under the successful efforts accounting method.

## Net Debt and Net Debt to EBITDAX (or Net Leverage)

Net Debt is calculated by subtracting cash and cash equivalents from total debt. Net Debt is a non-GAAP measures which our management believes are also useful to investors when assessing our leverage since we have the ability to and may decide to use a portion of our cash and cash equivalents to retire debt. Our management uses this measures for that purpose.

## Other Defined Terms

Present Value Index (PVI10) is often used by management as a return-on-investment metric and defined as the estimated net present value (using a 10% discount rate) of the future net cash flows from such reserves (for which we utilize certain assumptions regarding future commodity prices and operating costs), adding back our direct net costs incurred in drilling and adding back our completing, constructing facilities, and flowing back such wells, and then dividing that sum by our direct net costs incurred in drilling, completing, constructing facilities, and flowing back such wells.

Twelve Months Ended: (\$ in millions)	March 31		December 31					
	2025	2024	2023	2022	2021	2020	2019	2018
	Coterra			Combined Cabot + Cimarex				
<b>Net income</b>	\$ 1,285	\$ 1,121	\$ 1,625	\$ 4,065	\$ 1,158	\$ 201	\$ 681	\$ 557
<b>Plus (less):</b>								
Interest expense, net					62	54	55	73
Interest expense	140	106	73	80				
Interest income	(54)	(62)	(47)	(10)				
(Gain) loss on debt extinguishment				(28)	-	-	-	-
Other expense (benefit)				(2)	-	-	1	-
Income tax expense (benefit)	280	224	503	1,104	344	41	219	141
Depreciation, depletion and amortization	1,914	1,840	1,641	1,635	693	391	406	417
Exploration	30	25	20	29	18	15	20	114
(Gain) loss on sale of assets	(4)	(3)	(12)	1	2	0	1	16
Non-cash loss (gain) on derivative instruments	165	101	54	(299)	(210)	(26)	58	(86)
(Earnings) loss on equity method investments	-	-	-	-	-	0	(80)	(1)
Equity method investment distributions	-	-	-	-	-	-	17	-
Stock-based compensation	65	62	59	86	57	43	31	33
Severance expense	-	-	12	62	46	-	3	-
Merger-related costs	-	-	-	7	72	-	-	-
<b>EBITDAX</b>	<b>\$ 3,821</b>	<b>\$ 3,414</b>	<b>\$ 3,928</b>	<b>\$ 6,730</b>	<b>\$ 2,242</b>	<b>\$ 719</b>	<b>\$ 1,412</b>	<b>\$ 1,264</b>
Legacy Cimarex EBITDAX					1,005	935	1,460	1,558
<b>Combined EBITDAX</b>	<b>\$ 3,821</b>	<b>\$ 3,414</b>	<b>\$ 3,928</b>	<b>\$ 6,730</b>	<b>\$ 3,247</b>	<b>\$ 1,654</b>	<b>\$ 2,872</b>	<b>\$ 2,822</b>

(\$ in millions)	March 31		December 31					
	2025	2024	2023	2022	2021	2020	2019	2018
	Coterra			Combined Cabot + Cimarex				
Total debt	\$4,280	\$3,535	\$2,161	\$2,181	\$3,125	\$3,134	\$3,220	\$2,726
Less: Cash and cash equivalents	(186)	(2,038)	(956)	(673)	(1,036)	(413)	(295)	(803)
Less: Short-term investments								
Net debt	\$4,094	\$1,497	\$1,205	\$1,508	\$2,089	\$2,721	\$2,925	\$1,923
TTM EBITDAX	\$3,821	\$3,414	\$3,928	\$6,730	\$3,247	\$1,654	\$2,872	\$2,822
<b>Net debt to TTM EBITDAX</b>	<b>1.1x</b>	<b>0.4x</b>	<b>0.3x</b>	<b>0.2x</b>	<b>0.6x</b>	<b>1.6x</b>	<b>1.0x</b>	<b>0.7x</b>



# Non-GAAP Reconciliations & Definitions

## Adjusted Pro Forma EBITDAX (trailing twelve months)

Adjusted Pro Forma EBITDAX is defined as pro forma net income plus pro forma interest expense, pro forma interest income, pro forma income tax expense, pro forma depreciation, depletion, and amortization (including impairments), pro forma exploration expense, pro forma gain and loss on sale of assets, pro forma non-cash gain and loss on derivative instruments, pro forma acquisition-related expenses, and pro forma stock-based compensation expense. Adjusted Pro Forma EBITDAX represents the effects of the Franklin Mountain Energy and Avant Natural Resources acquisitions as if they had occurred on January 1, 2024. Adjusted Pro Forma EBITDAX is presented on our management's belief that this non-GAAP measure is useful information to investors when evaluating our ability to internally fund exploration and development activities and to service or incur debt after the acquisitions without regard to financial or capital structure. Our management uses Adjusted Pro Forma EBITDAX for that purpose. Adjusted Pro Forma EBITDAX is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating activities, pro forma net income or net income, as defined by GAAP, or as a measure of liquidity.

## Net Debt to Adjusted Pro Forma EBITDAX

Total debt to net income is defined as total debt divided by net income. Net debt to Adjusted Pro Forma EBITDAX is defined as net debt divided by trailing twelve month Adjusted Pro Forma EBITDAX. Net debt to Adjusted Pro Forma EBITDAX is a non-GAAP measure which our management believes is useful to investors when assessing our credit position and leverage.

Trailing Twelve Months Ended:	March 31	December 31
(\$ in millions)	2025	2024
Pro forma net income	\$ 1,493	\$ 1,401
Plus (less):		
Pro forma interest expense	251	250
Pro forma interest income	(54)	(62)
Pro forma income tax expense	338	290
Pro forma depreciation, depletion and amortization	2,240	2,197
Pro forma exploration	30	25
Pro forma gain on sale of assets	(4)	(3)
Pro forma non-cash loss on derivative instruments	291	101
Acquisition-related expenses	13	-
compensation	65	62
<b>Adjusted Pro Forma EBITDAX (trailing twelve months)</b>	<b>\$ 4,663</b>	<b>\$ 4,261</b>

	March 31	December 31
(\$ in millions)	2025	2024
Net debt (as defined previously)	\$ 4,094	\$ 1,497
Adjusted Pro Forma EBITDAX (Trailing twelve months)	4,663	4,261
<b>Net debt to Adjusted EBITDAX</b>	<b>0.9x</b>	<b>0.4x</b>