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1Q25 Earnings Presentation

May 2025

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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.

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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 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

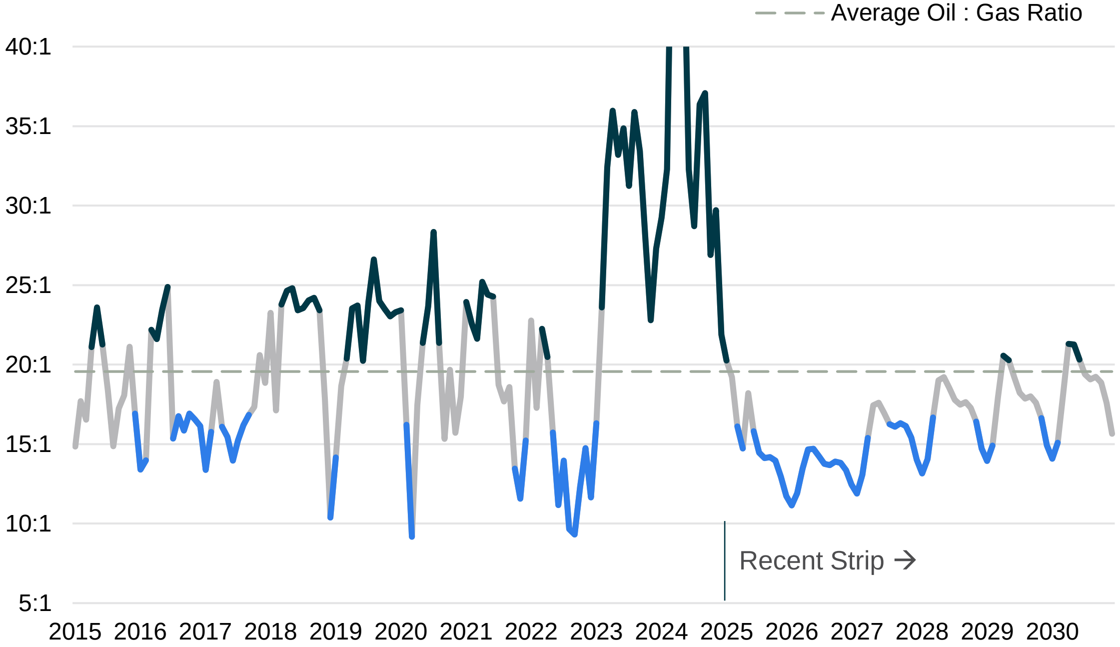
Oil-to-gas price ratios can, and have historically decoupled, especially during periods of extreme volatility

Uniquely Positioned to Weather Volatility

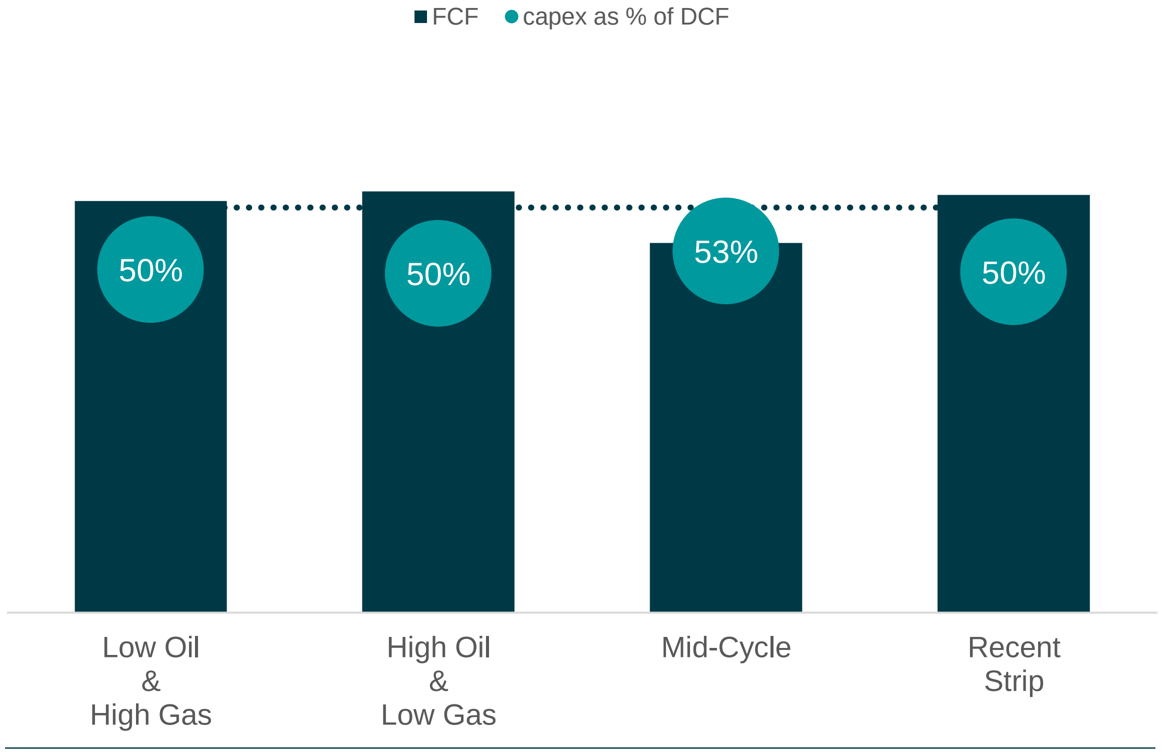
Diversified Commodity Portfolio with Demonstrated Capital Flexibility

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



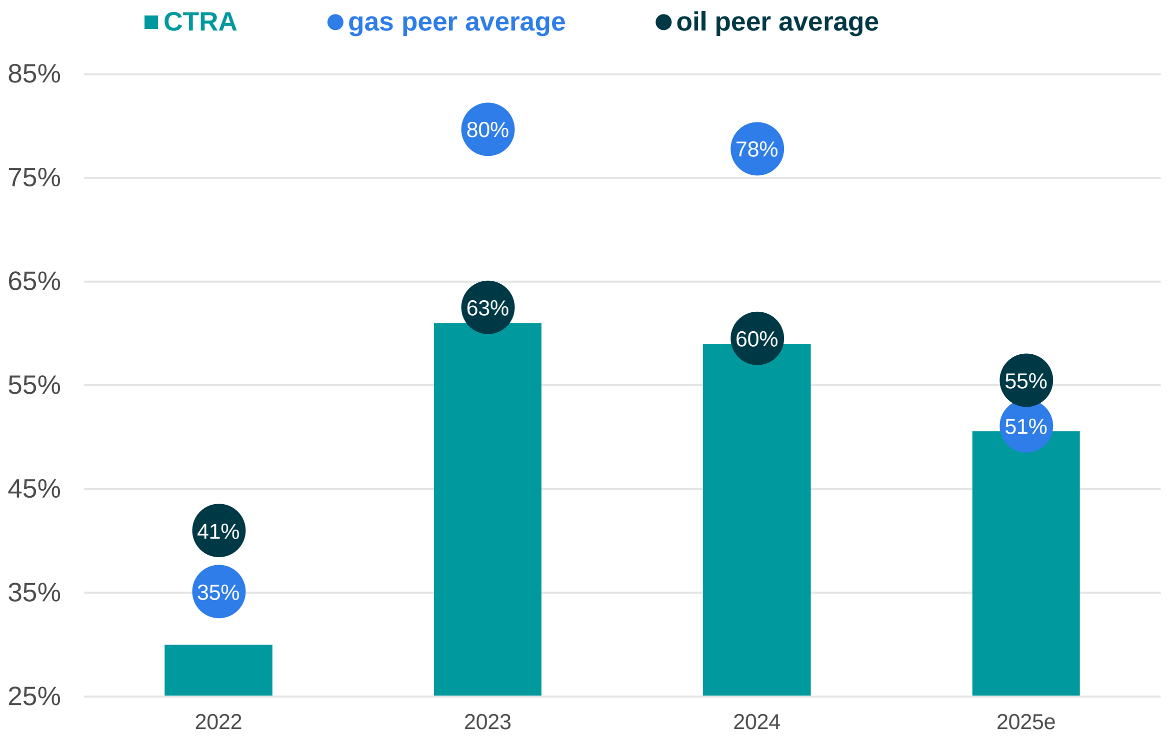
WTI & HH Oil : Gas Ratio	Low Oil & High Gas	High Oil & Low Gas	Mid-Cycle	Recent Strip
	$50 & $4.75 11:1	$75 & $2.75 29:1	$65 & $3.25 17:1	~$60 & ~$4.00 15:1

Note: Strip prices as of 4/28/25.1) Reinvestment rate defined as capex as % of DCF. Based on DCF of $4.3 billion and FCF of $2.1 billion. See appendix for non-GAAP definitions.

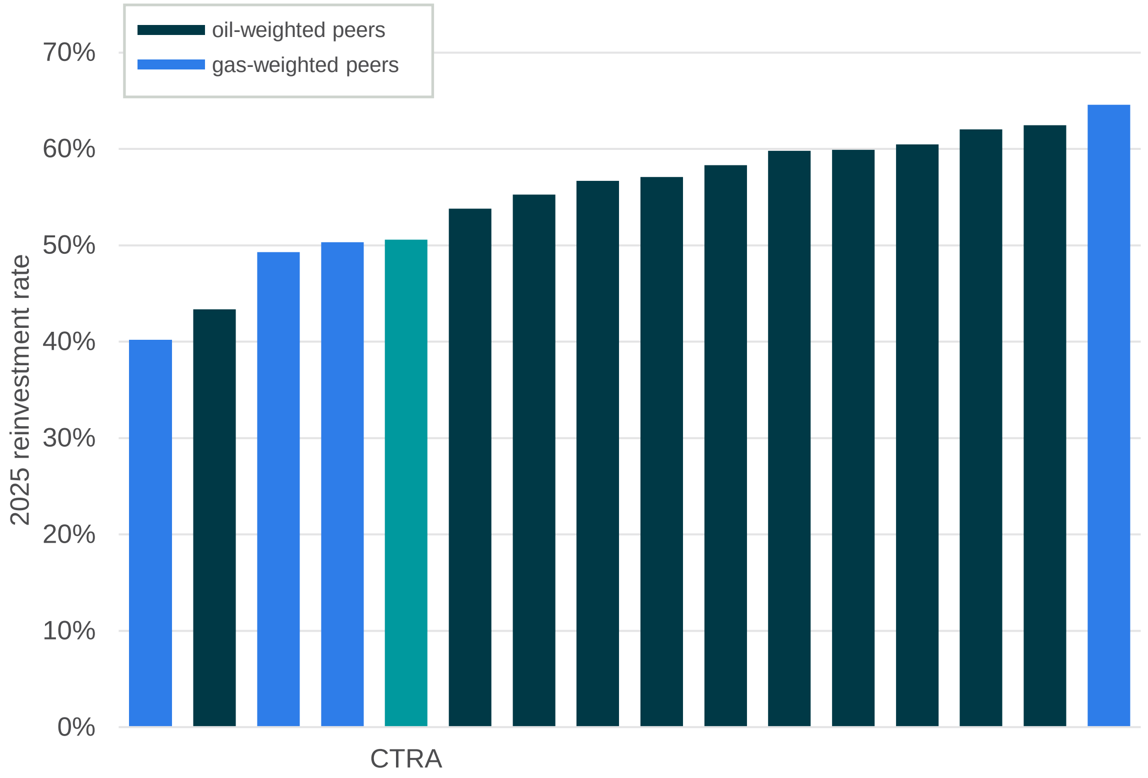
Disciplined Approach to Capital Investment

Differentiated reinvestment rate through the commodity cycles

Conservative historical reinvestment rate



Low reinvestment among peers in 2025



Source: Factset consensus. Reinvestment rate defined as capex as % of DCF. See appendix for non-GAAP reconciliations and definitions. 2025e CTRA reinvestment rate based on guidance, at recent strip prices. See appendix for commodity price assumptions. Peers include COP, EOG, FANG, OXY, DVN, EQT, EXE, PR, OVV, APA, AR, CHRD, RRC, MTDR, CIVI.

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 ~0.9x[1], retired $250 million of Term Loans during 1Q

Note: See appendix for non-GAAP reconciliations and definitions. 1) Net debt to pro forma adjusted EBITDAX for the trailing twelve months.

Beat Midpoint of 1Q25 Production Guidance & Updating Annual Guidance

Higher production & lower capex driving improved capital efficiency

		1Q25		2025e
Oil mbod	guidance	134.0 – 144.0	February guid.	152.0 – 168.0
	actual	141.2	updated guid.	155.0 – 165.0
Gas mmcfd	guidance	2,850 – 3,000	February guid.	2,675 – 2,875
	actual	3,044	updated guid.	2,725 – 2,875
Total Volumes mboed	guidance	710 – 750	February guid.	710 – 770
	actual	747	updated guid.	720 – 770
Capex $ millions	guidance	$525 – $625	February guid.	$2,100 – $2,400
	actual	$552	updated guid.	$2,000 – $2,300

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Note: Incurred capex shown; not cash basis. See appendix for non-GAAP reconciliations and definitions.

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[1]

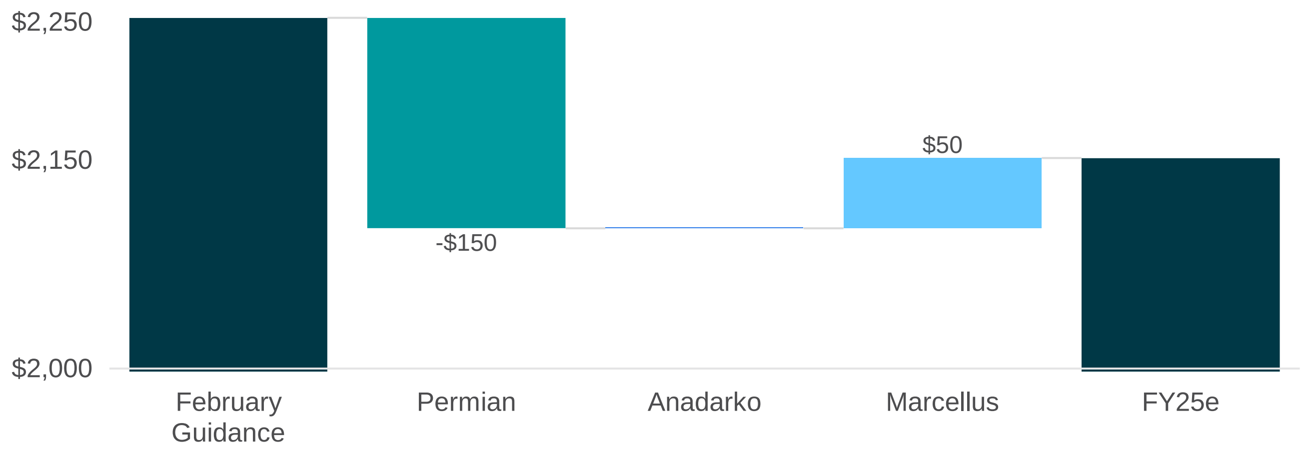
~$2.1 billion Free Cash Flow[2], +69% YoY
driven by higher expected commodity prices and disciplined reinvestment

Production Guidance
720-770 mboed | 155-165 mbod | 2,725-2,875 mmcfd

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



Permian D&C: ~$1,450mm

- Down from previous guidance by ~$120mm
- Lower activity, cost and service deflation, and acquisition synergies
- 3 consistent crews
- Expect to average 7 rigs in 2H25, down from current 10 rigs

Anadarko D&C: ~$230mm

- Consistent with previous guidance

Marcellus D&C: ~$300MM

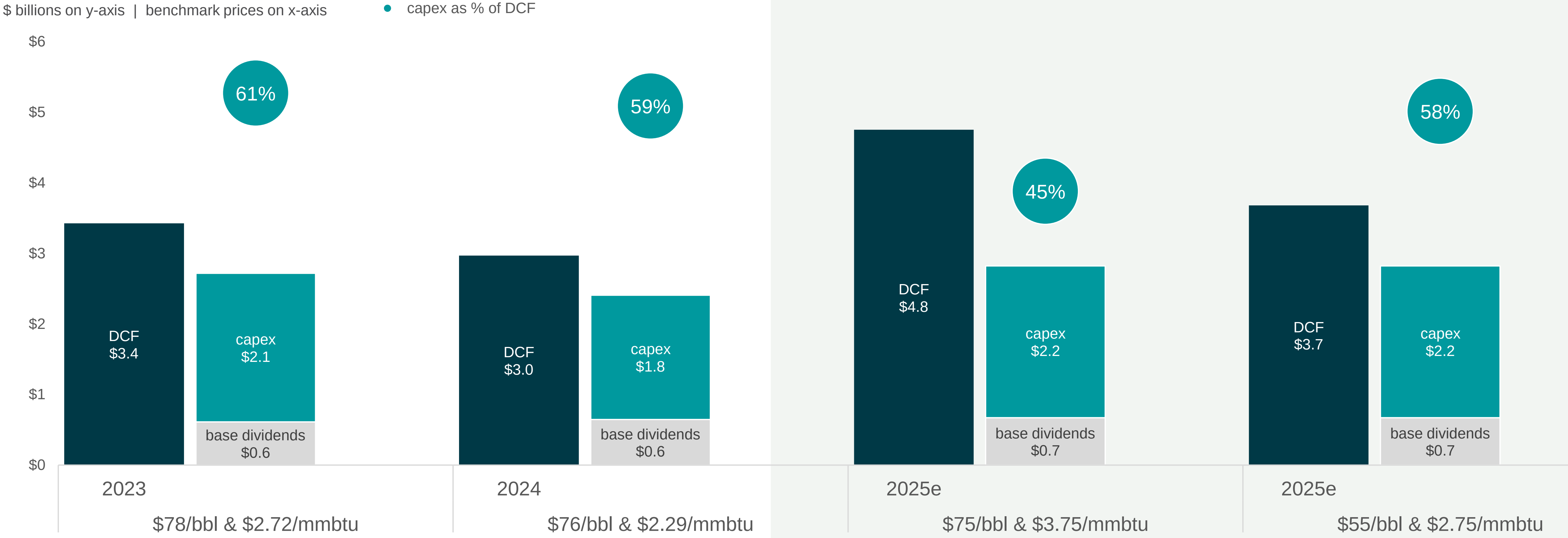
- Up from previous guidance by ~$50mm
- Should macro conditions warrant, could increase capital an incremental ~$50mm in late 2025
- Restarted 2 rigs in April
- Increased drilling will drive next winter's volumes

Note: Permian capital expenditure reduction of $150mm is inclusive of MSI. 1) Reinvestment rate defined as capex as % of DCF. 2) See appendix for commodity price assumptions

Committed to Capital Discipline & Free Cash Flow Generation

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

$ billions on y-axis | benchmark prices on x-axis



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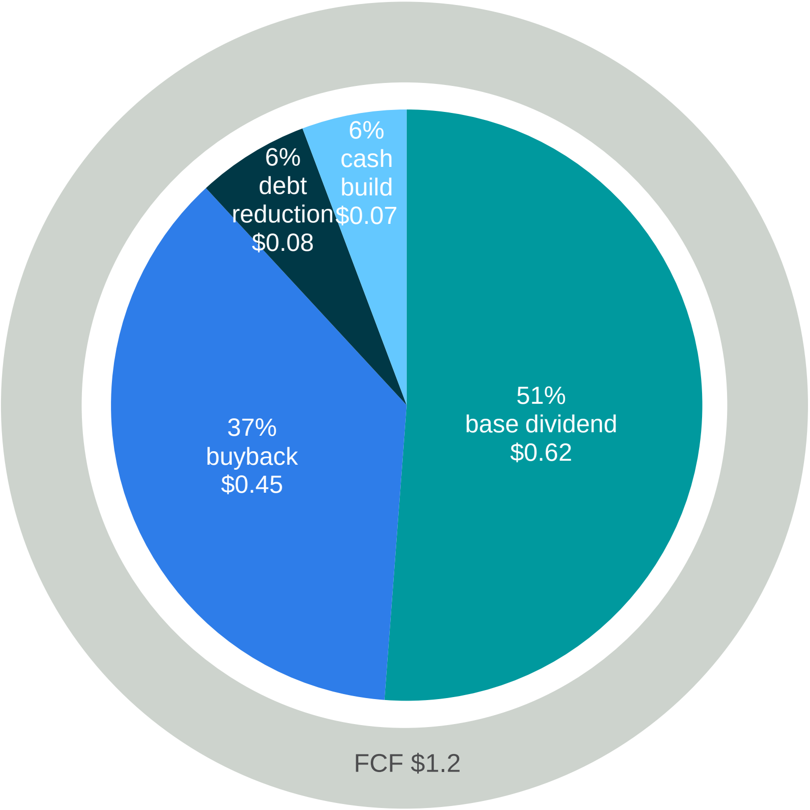
Note: See appendix for non-GAAP reconciliations and definitions. Capex shown is incurred or expected to be incurred (non-cash basis), with 2025e at mid-point of guidance. Dividends shown are declared dividends within the year, not cash paid. 2025e base dividends = 1Q25 declared dividends of $168 mm + share count, per cover of 1Q25 10Q * $0.66/sh (for remaining 3 quarters of the year). Future dividends are subject to board approval.

Committed to Returning Value

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

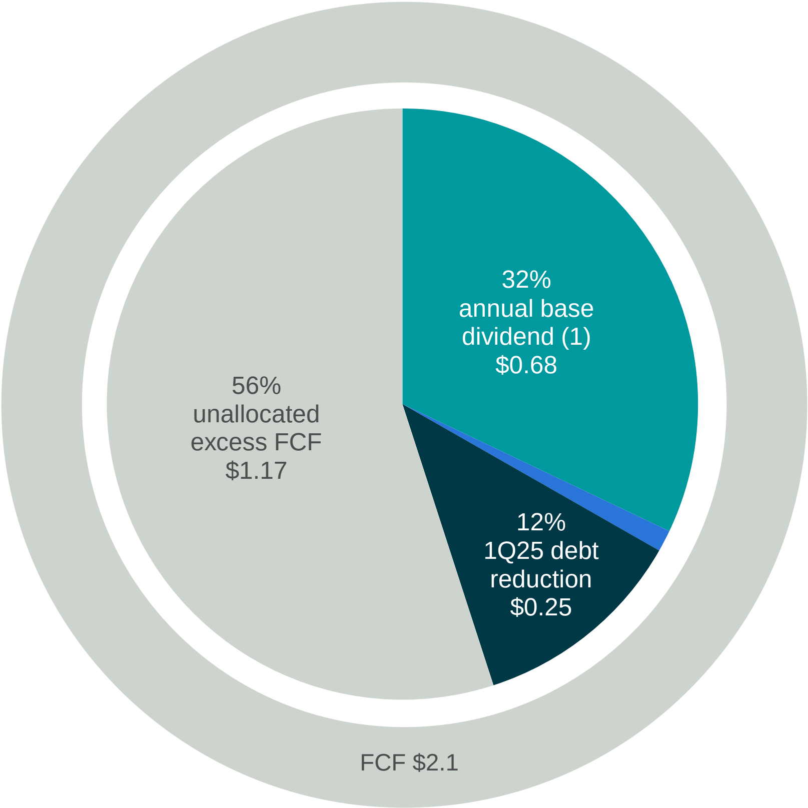
2024 FCF $1.2bn

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[2]
- $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

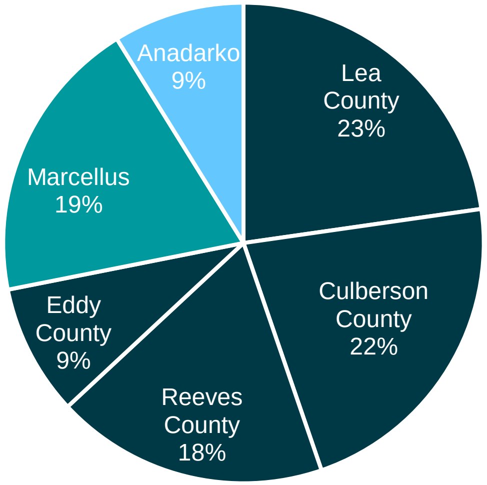
Benchmark price assumptions of $75/bbl and $3.75/mmbtu

~$31 billion of Economic Capex Opportunities

estimated capex by PVI_{10} bucket:

~$14bn, or ~45%, of capex is expected to generate 2.0x PVI_{10} or better

estimated total footage by asset area:



Implied Inventory Duration[1]

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

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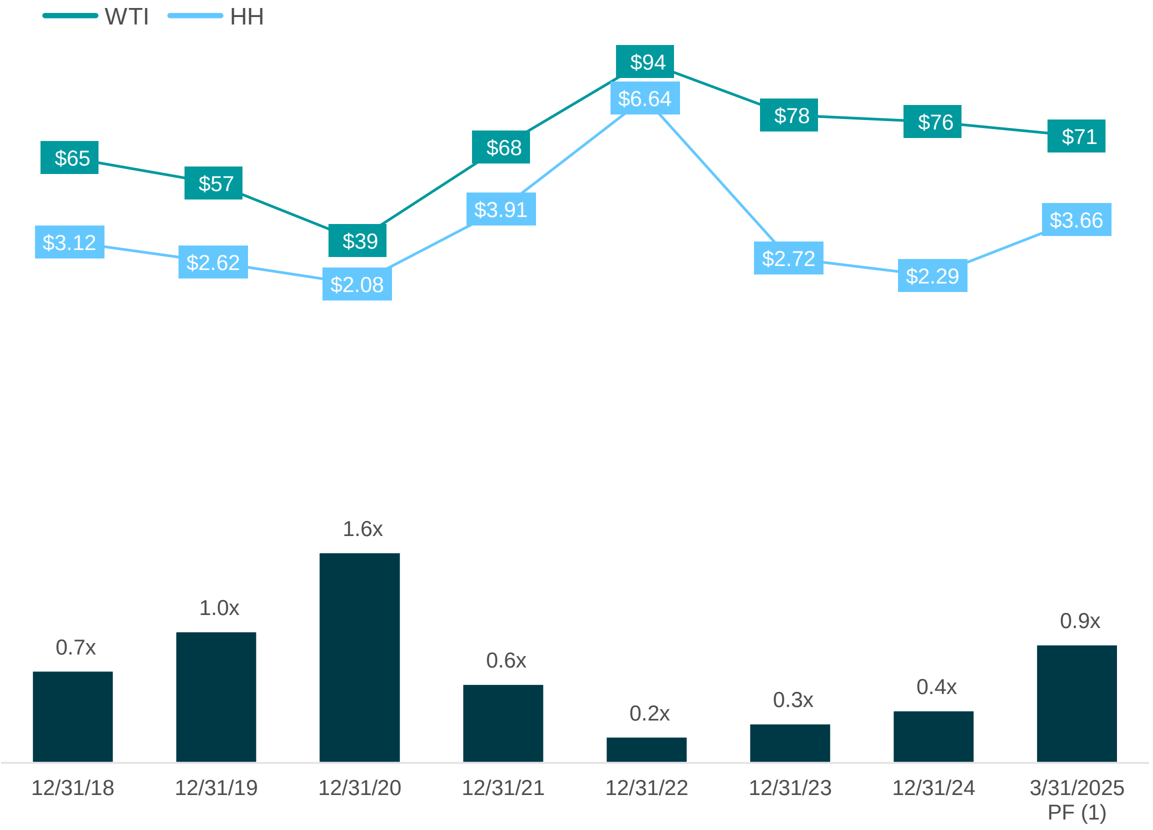
Note: Estimates as of February 2025. See appendix for non-GAAP reconciliations and definitions, and other defined terms. 1) Calculated midpoints based on average 2025e-2027e D&C spend and $75 WTI & $3.75 Henry Hub.

Prioritizing Financial Flexibility

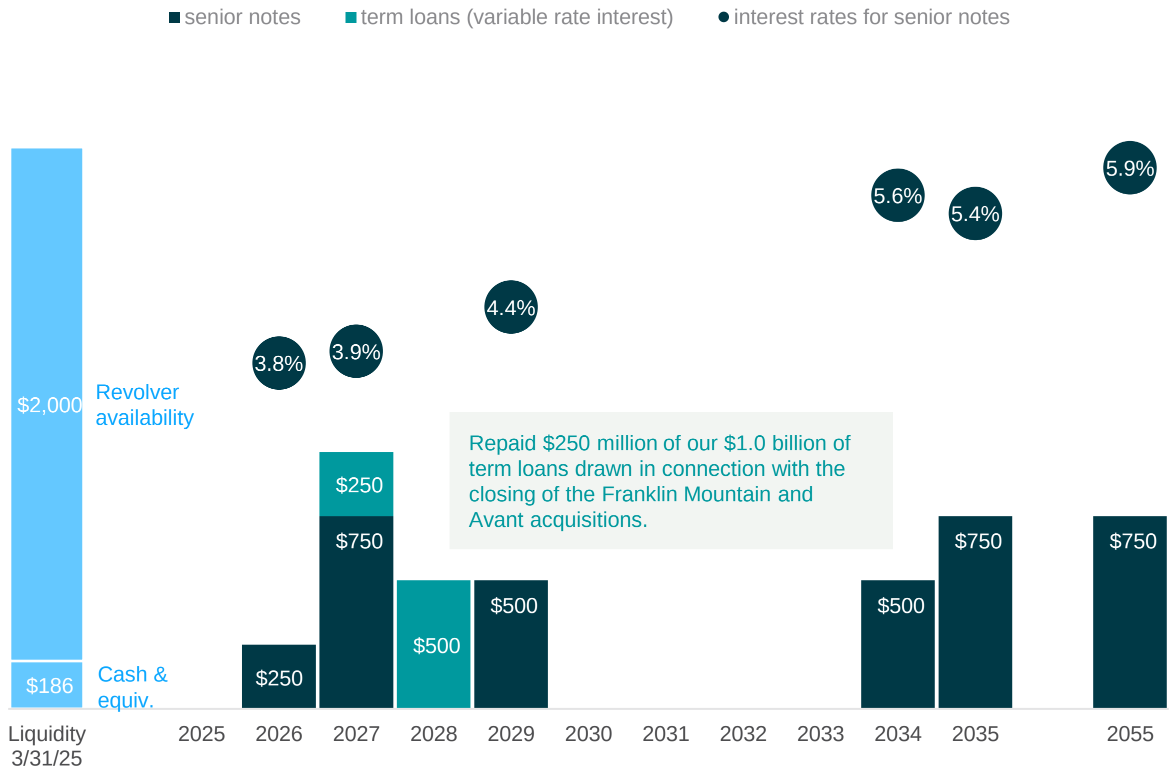
History of Conservative Net Leverage



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

Liquidity & Debt Maturity Profile

$mm and average rates



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

Note: See appendix for non-GAAP reconciliations and definitions. Commodity prices are trailing-twelve-month benchmark prices.1) Net debt to pro forma adjusted EBITDAX for the trailing twelve months.

Permian Asset Overview – 2025 Operational Outlook

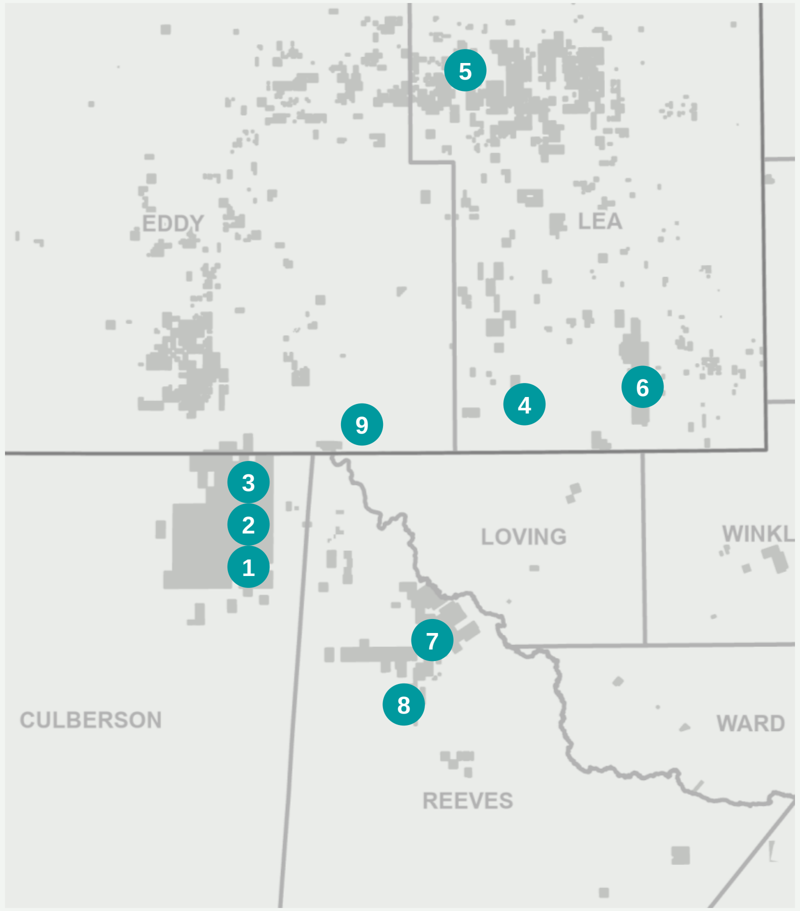
$1,450 million
Midpoint D&C CapEx

10,600'	$960	150-165
Avg. Lateral Length[1]	Avg. Well Cost per Foot[1]	Net Wells Online

1) Based on 2025e operated, completed wells. Note: Spend for a well is incurred over a period of 6-12 months, which does not necessarily fall within a single calendar year. $ per foot includes drilling, completion, facilities and post-completion capital

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. Marmaconda

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

8. Castle

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

Eddy County, NM

9. Tar Heel

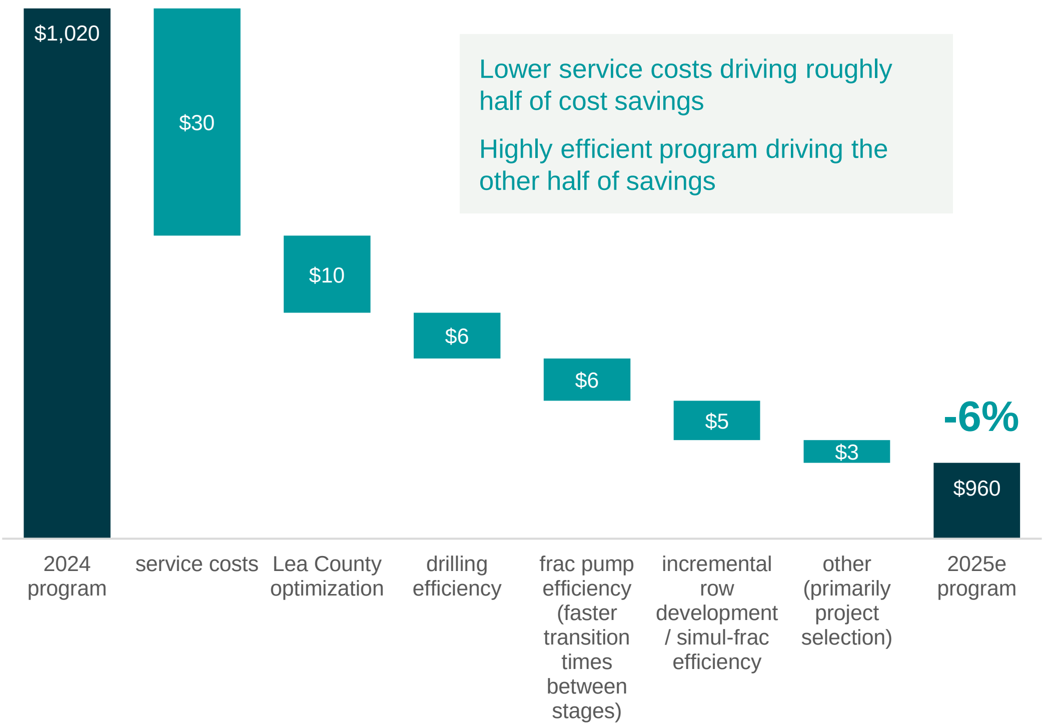
- 6 gross wells (100% WI), first prod 2Q25

Note: DSU = drilling spacing units; wps = wells per section.

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

$ per foot cost estimates

Permian reduction driven by operational efficiencies

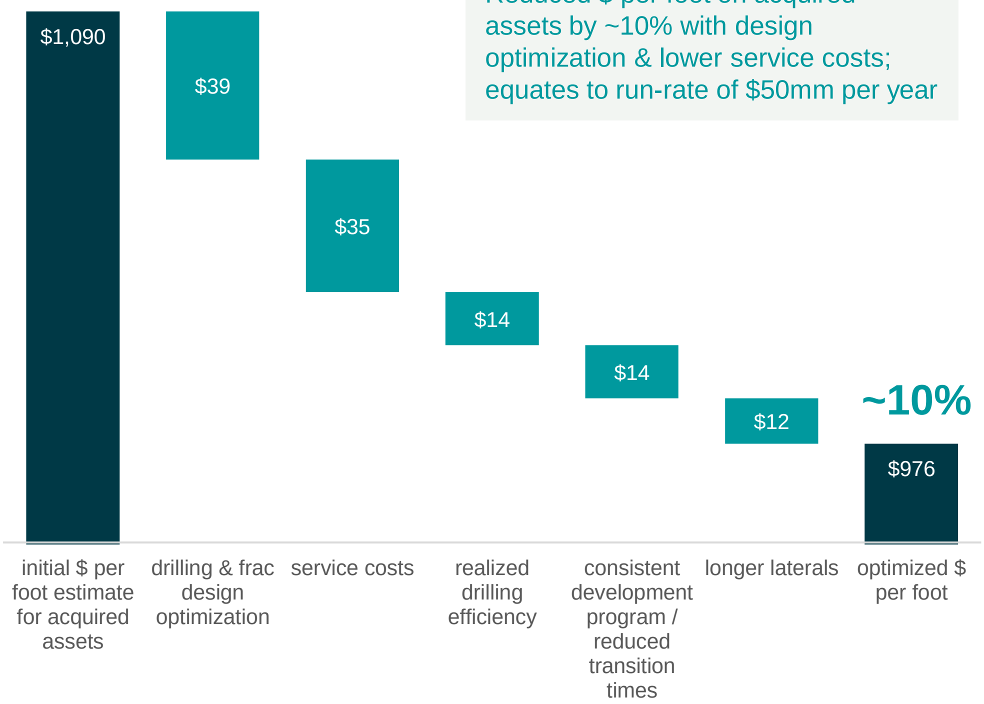


Lower service costs driving roughly half of cost savings

Highly efficient program driving the other half of savings

Synergies on our newly acquired Lea County asset

Reduced $ per foot on acquired assets by ~10% with design optimization & lower service costs; equates to run-rate of $50mm per year

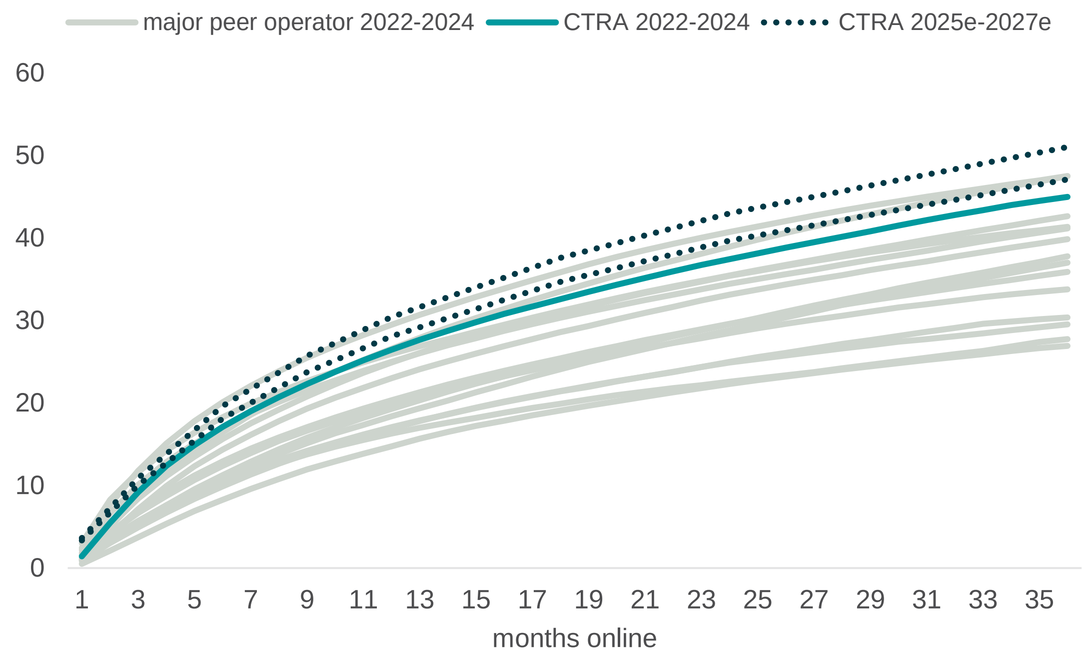


Note: $ per foot estimates include drilling, completion, facilities and post-completion costs; based on 2025e operated, completed wells.

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

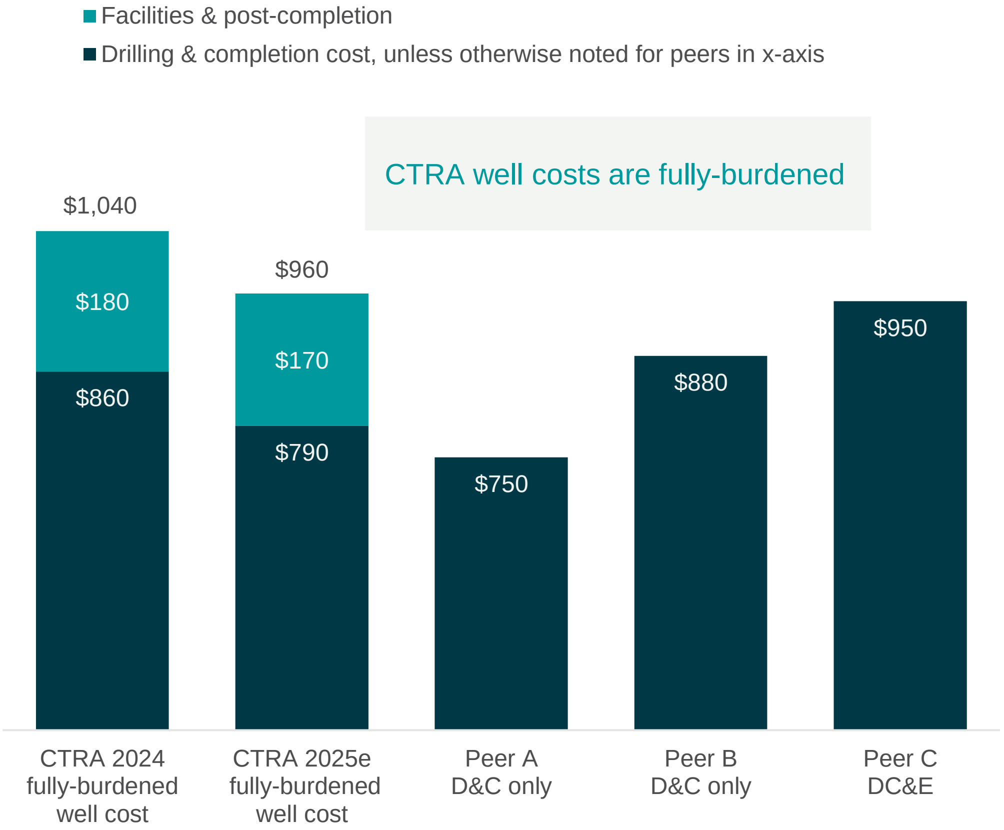
Delaware Productivity[1]

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

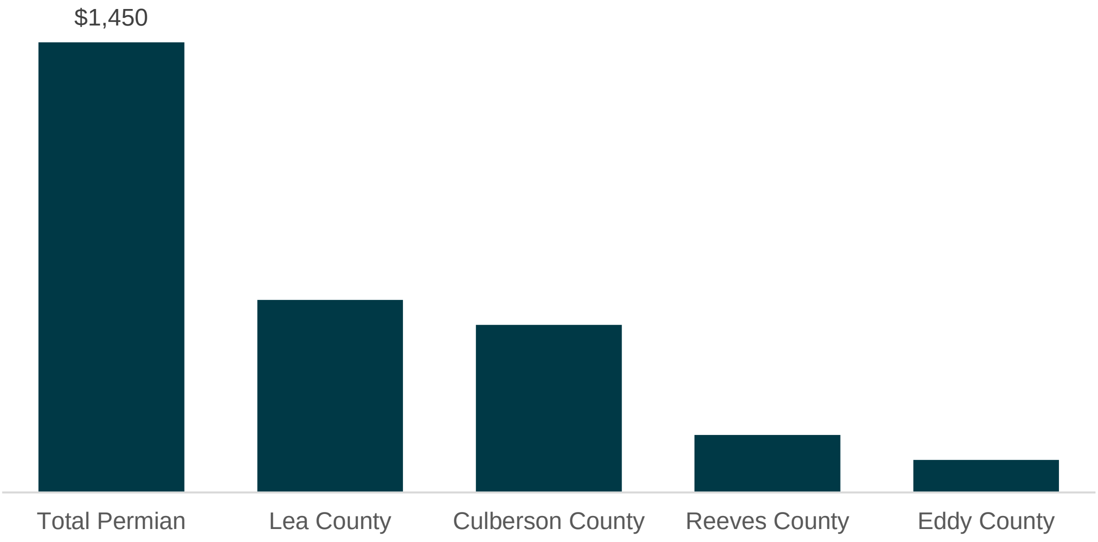
Recent Delaware D&C Well Costs per Foot[2]



1) Source: Enverus Prism for historical data and internal forecasts for future estimates. Filtered to >8,500’ laterals. 2) Sourced from recent company disclosure. CTRA D&C cost estimate based on operated wells with expected frac end-date in 2025. Peers A, B and C companies that publish Delaware Basin well costs.

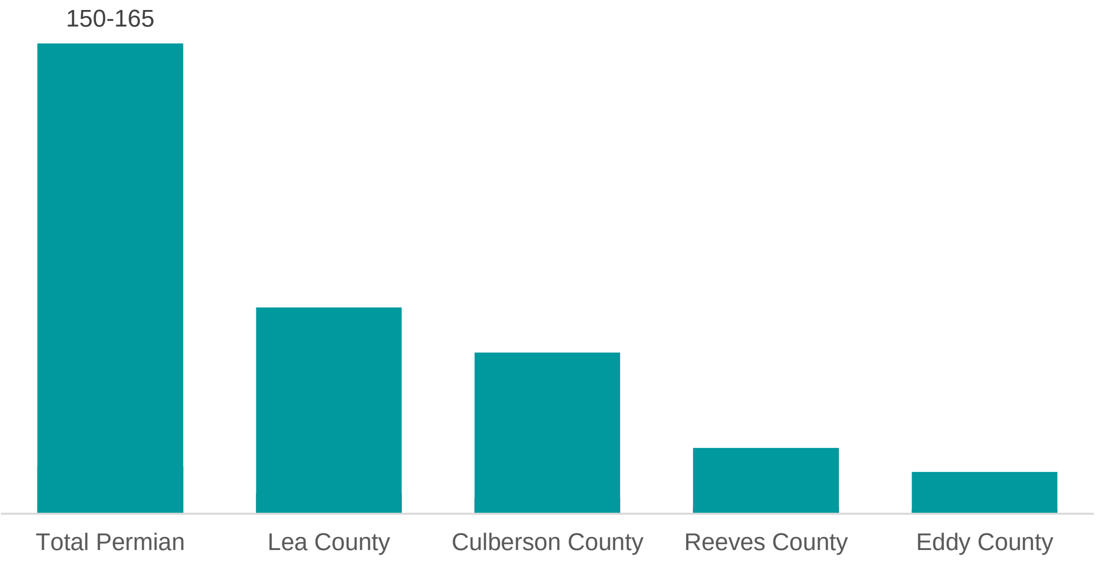
2025 Permian Development Program

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



Leading edge $ per foot estimates:	$1,050 per foot	$830 per foot	$1,020 per foot	$990 per foot

2025e net wells online



Primary target formations:	Upper Wolfcamp & Bone Spring	Upper Wolfcamp	Upper Wolfcamp	Upper Wolfcamp & Bone Spring

Note: See appendix for non-GAAP reconciliations and definitions. D&C costs and $ per foot estimates include drilling, completion, facilities and post-completion costs.

Marcellus Asset Overview – 2025 Operational Outlook

$300 million

Midpoint D&C CapEx

19,100’ Avg. Lateral Length for Upper[1]	**$660** Avg. Well Cost per Foot[1]	**10-15** Net Wells Online ~30% Upper & ~70% Lower
14,700’ Avg. Lateral Length for Lower[1]	**$860** Avg. Well Cost per Foot[1]	

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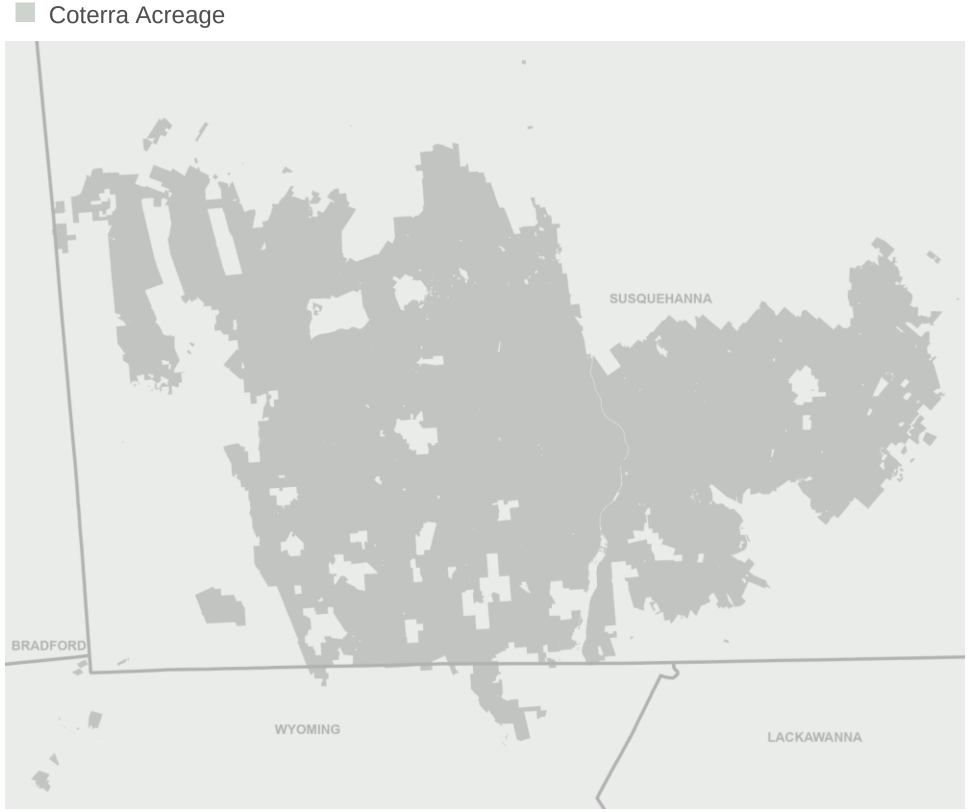
1) Based on 2025e operated, completed wells. Note: Spend for a well is incurred over a period of 6-10 months, which does not necessarily fall within a single calendar year. $ per foot includes drilling, completion, facilities and post-completion capital

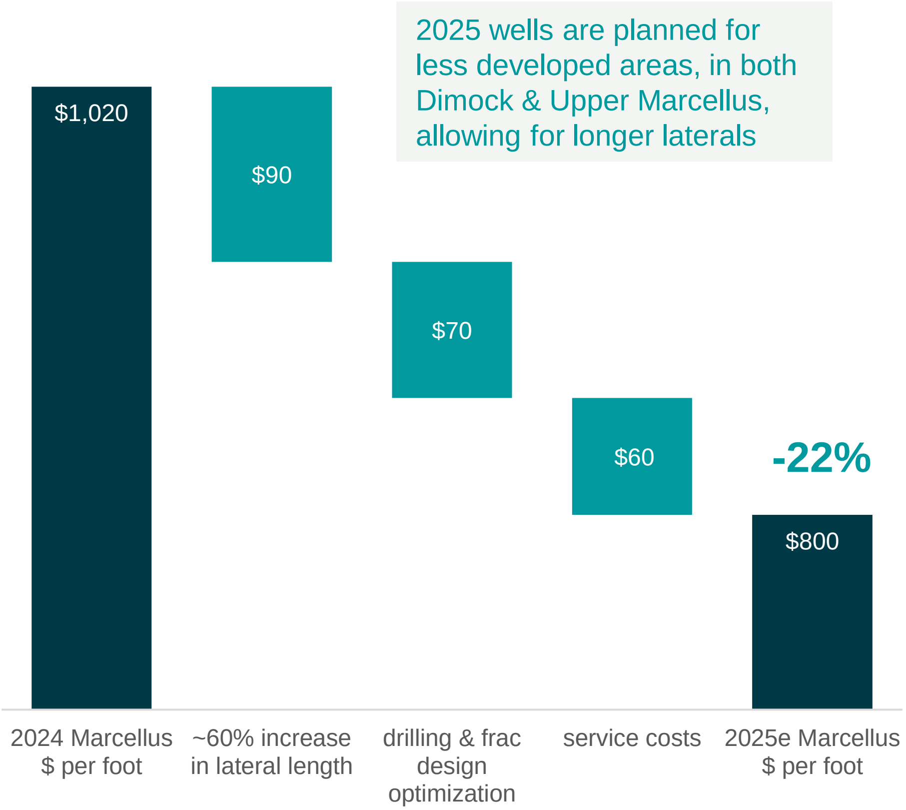
Marcellus Asset Overview

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

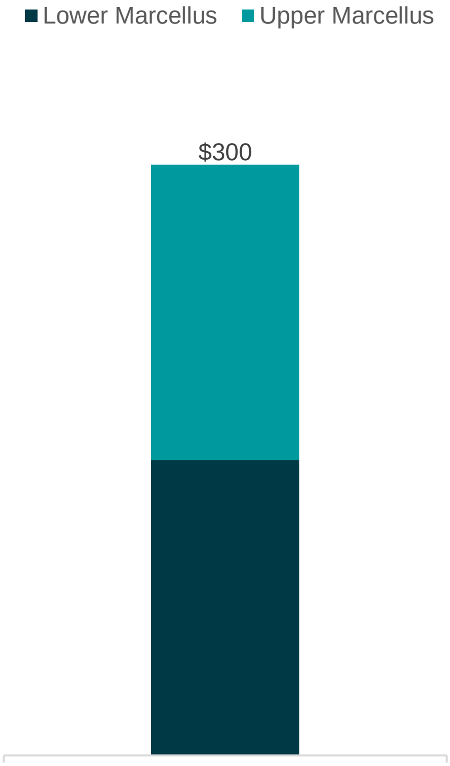
Susquehanna County acreage leverages highly productive Marcellus



Reduction in well costs YoY driven by significantly longer laterals



2025e midpoint D&C capex in $ millions



Note: $ per foot estimates include drilling, completion, facilities and post-completion costs; based on 2025e operated, completed wells.

Anadarko Asset Overview – 2025 Operational Outlook

$230 million

Midpoint D&C CapEx

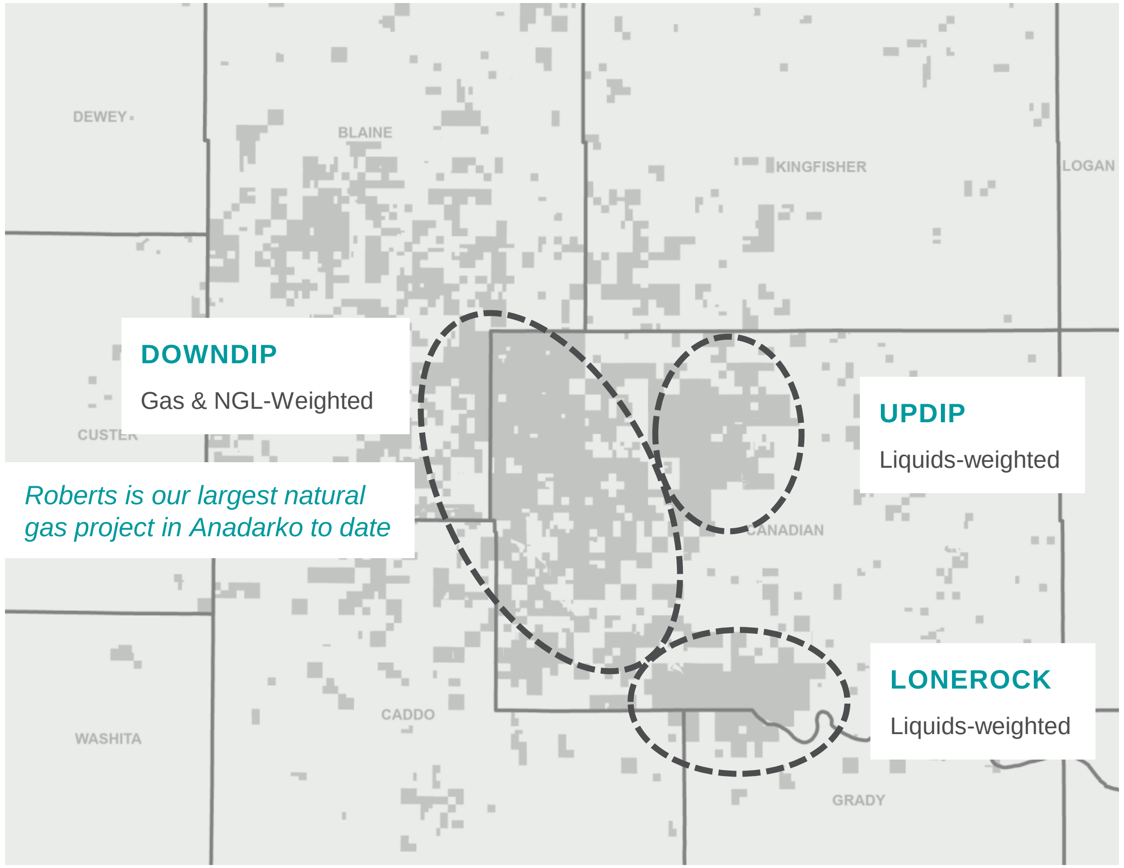
11,080'	$1,070	15-25
Avg. Lateral Length[1]	Avg. Well Cost per Foot[1]	Net Wells Online

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

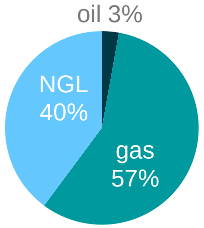
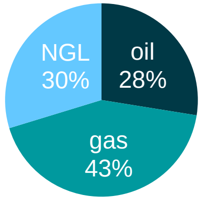
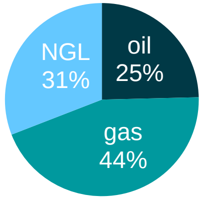
Anadarko Asset Overview

Anadarko sub-regions

Coterra Acreage



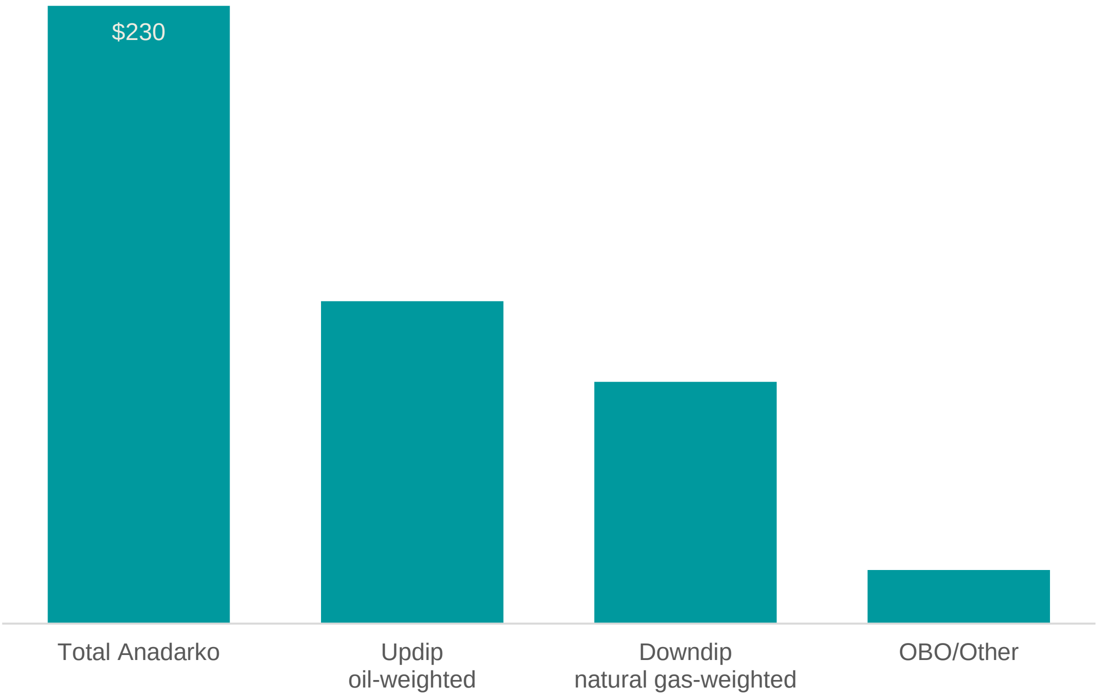
Major 2025 Anadarko projects

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)	
3Q 2025	Hufnagel	4.4 net (6 gross)	Updip (Primarily Woodford, 2 gross Meramec)	
3Q 2025	Clark	5.6 net (6 gross)	Updip (Primarily Woodford, 2 gross Meramec)	

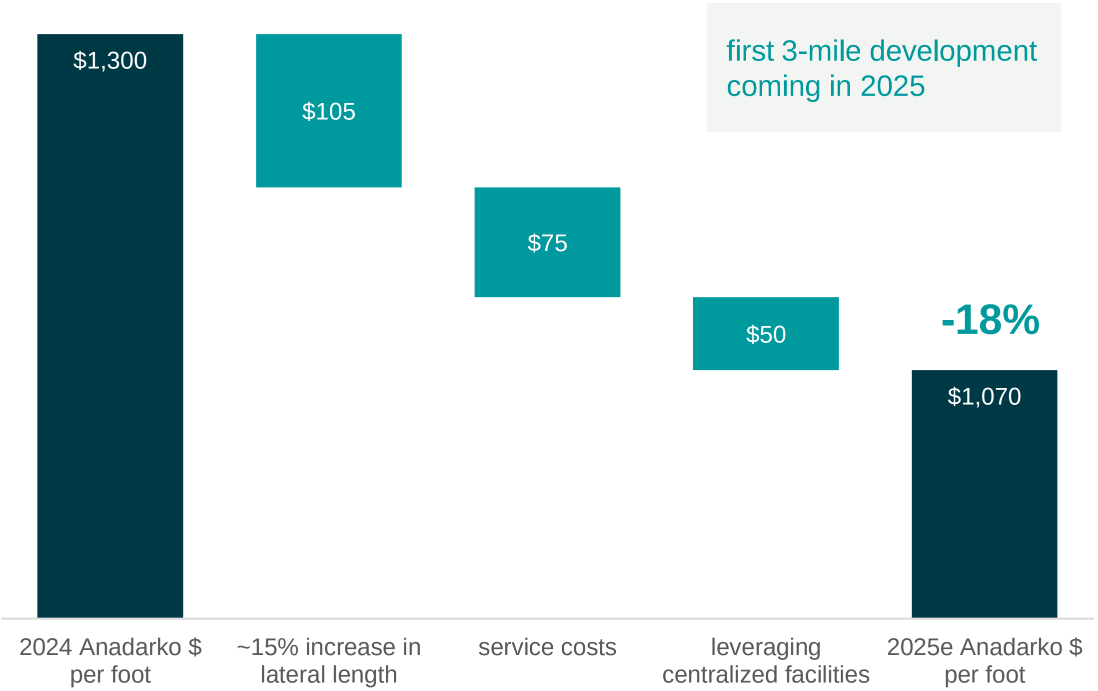
Anadarko Investment Allocation by Area & Cost Savings

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[1]



See appendix for non-GAAP reconciliations and definitions, and other defined terms. 1) $ per foot estimates include drilling, completion, facilities and post-completion costs; based on 2025e operated, completed wells.

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Appendix

High-Quality, Long-Life, Diversified Asset Portfolio

Multi-Basin Portfolio

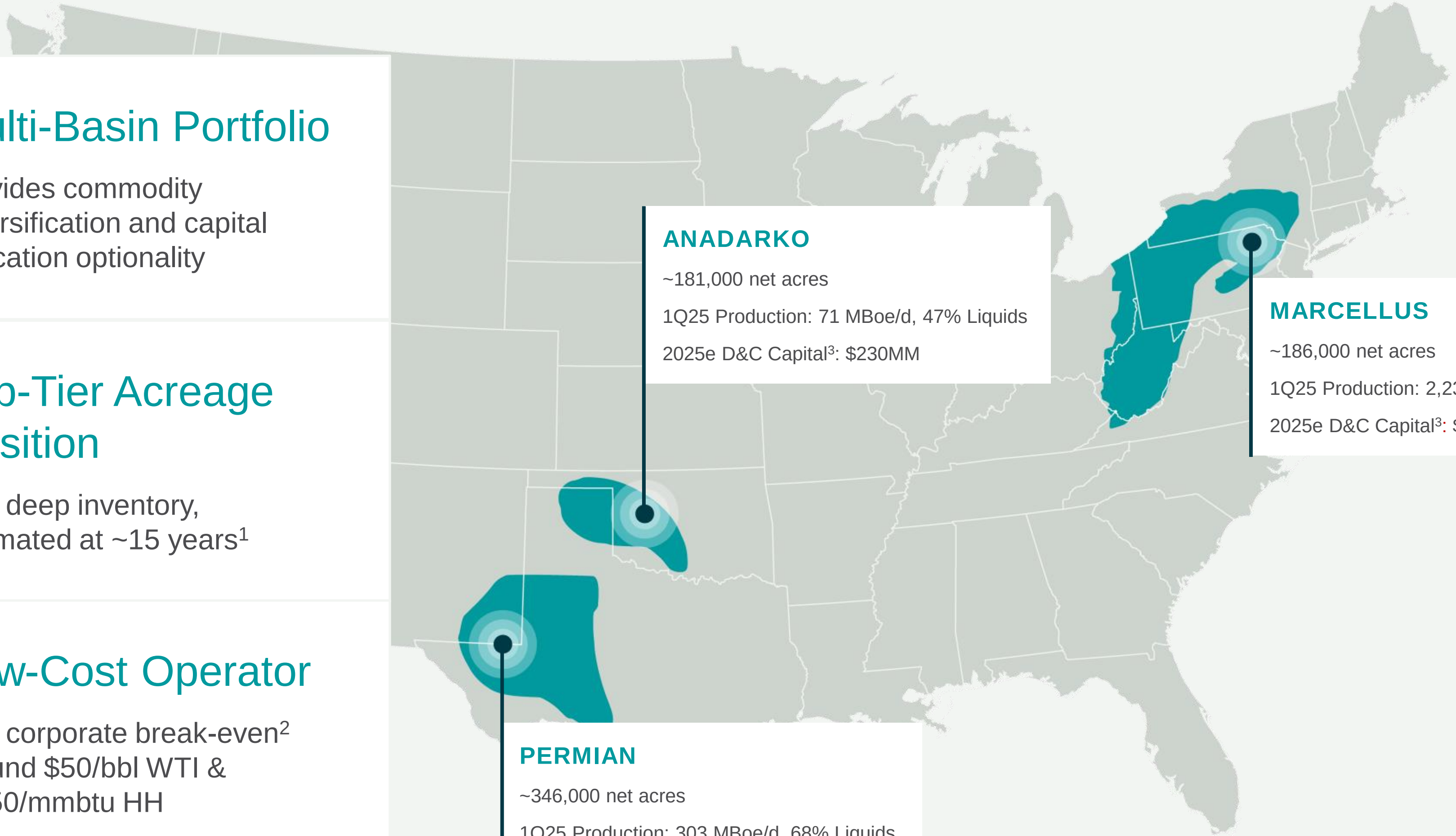
provides commodity diversification and capital allocation optionality

Top-Tier Acreage Position

with deep inventory, estimated at ~15 years[1]

Low-Cost Operator

with corporate break-even[2] around $50/bbl WTI & $2.50/mmbtu HH



ANADARKO

~181,000 net acres

1Q25 Production: 71 MBoe/d, 47% Liquids

2025e D&C Capital[3]: $230MM

MARCELLUS

~186,000 net acres

1Q25 Production: 2,233 MMcf/d

2025e D&C Capital[3]: $300MM

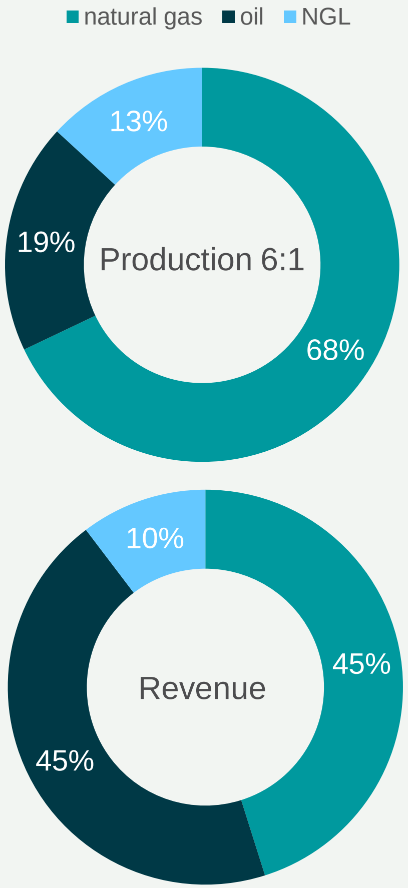
PERMIAN

~346,000 net acres

1Q25 Production: 303 MBoe/d, 68% Liquids

2025e D&C Capital[3]: $1,450MM

1Q25 Commodity Splits



1) Assumes average 2025e-2027e D&C spend and $75 WTI & $3.75 Henry Hub. 2) Meaning FCF covers base dividend for multiple years. See appendix for non-GAAP reconciliations and definitions.
3) D&C Capital = Drilling & Completion Capital, which includes drilling, completion, facilities and post-completion capital.

Executive Compensation Tied to Emissions Reduction Metrics

20% of total short-term incentive potential

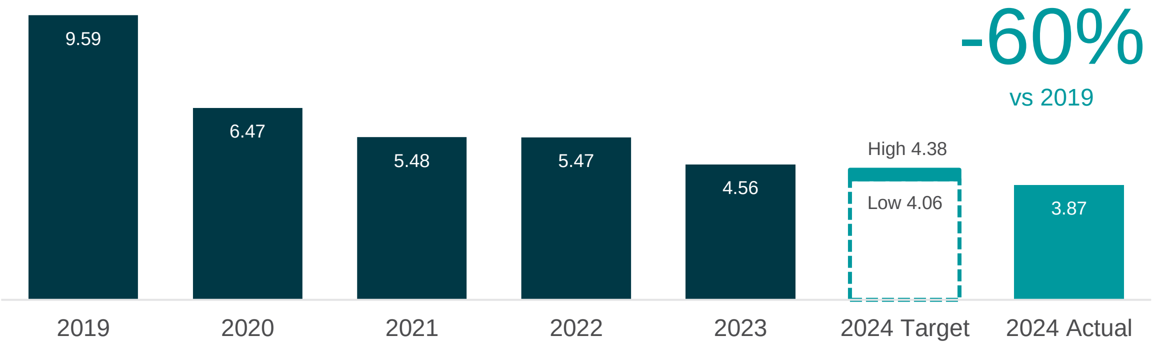
Climate Targets

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_2e/Gross Mboe Produced)	4.22	3.84
Methane Intensity (MT CH_4, Emitted / Gross MT CH_4, 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

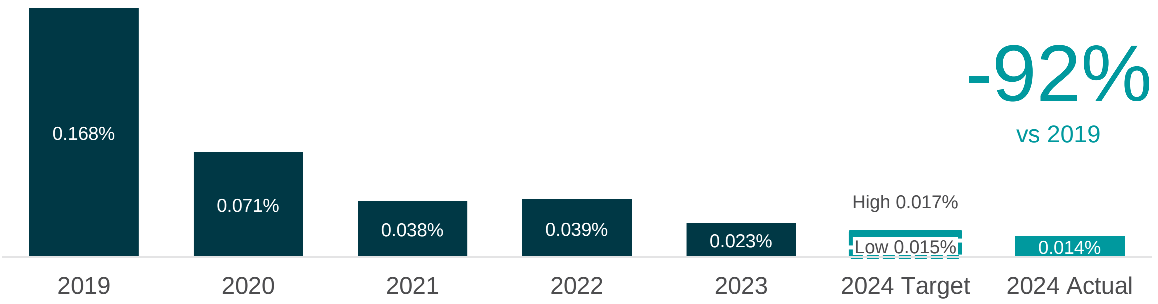
Greenhouse Gas Emissions Intensity

MT CO_2e / Gross Mboe Produced



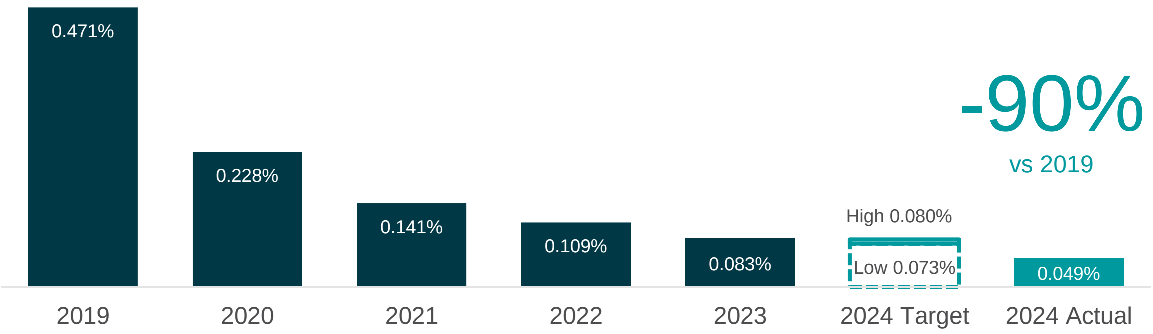
Methane Emissions Intensity

MT CH_4 Emitted / Gross MT CH_4 Produced



Total Company Flare Intensity

Volume of Gas Flared / Volume of Gas Produced



Figures listed above include only Scope 1 Subpart W reportable emissions. 2019 to 2021 figures are based on combined results for Cabot & Cimarex. 2024 Actuals are preliminary and not yet finalized by the EPA.

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

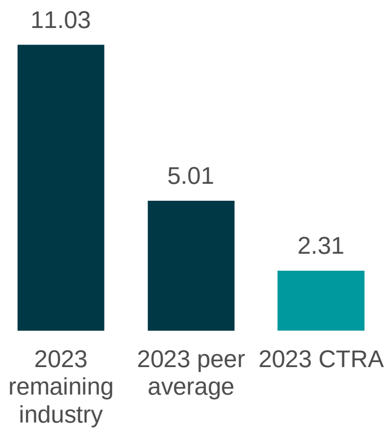
- Performing aerial methane detection campaigns across our operating areas
- Added new metric in 2024, Findings / Flight, tied to executive compensation

Upstream Greenhouse Gas Intensity vs. Peers & Industry

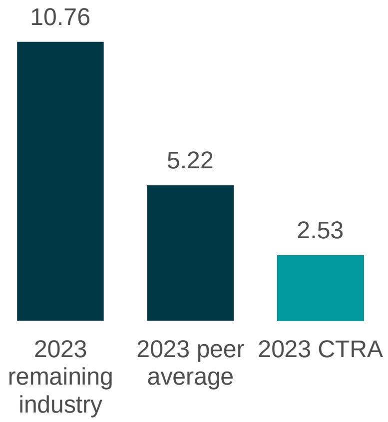
GHG Intensity (MT CO2e / Gross Mboe)

We analyze our upstream emissions on a standalone basis to compare our performance against our peers[1], 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:

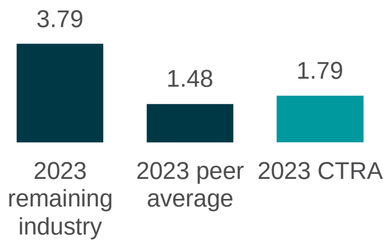
All U.S. basins



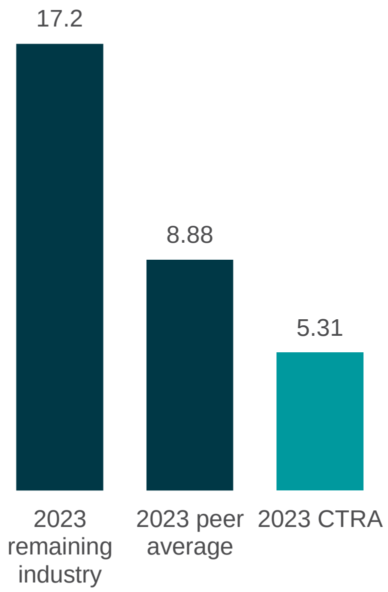
Permian



Marcellus



Anadarko



COTERRA

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

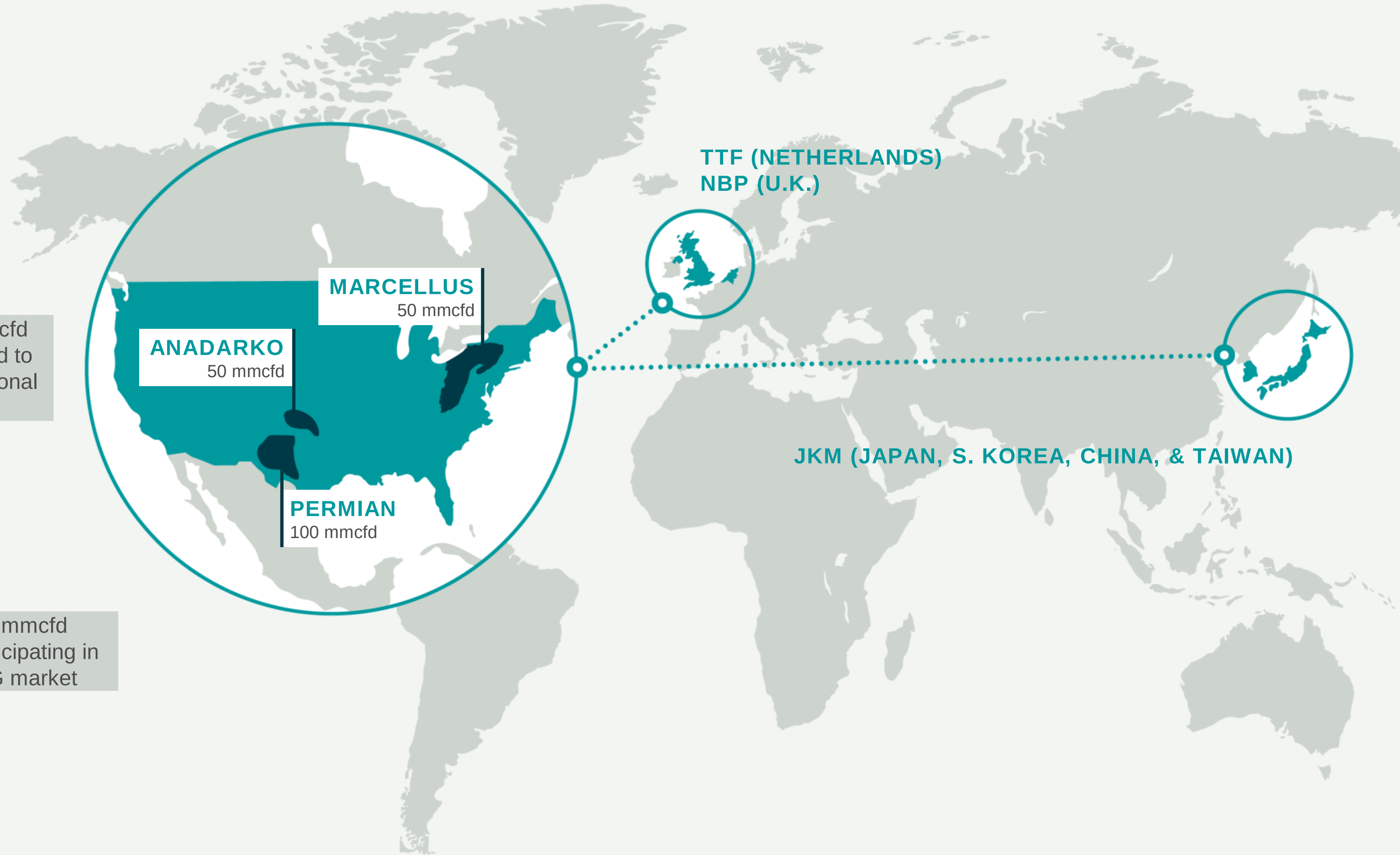
Diversifying Gas Portfolio with New LNG Contracts

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

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

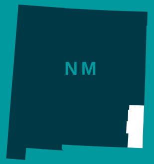
200 mmcfd to be tied to international pricing

550 mmcfd participating in LNG market



1) Facility is operating.

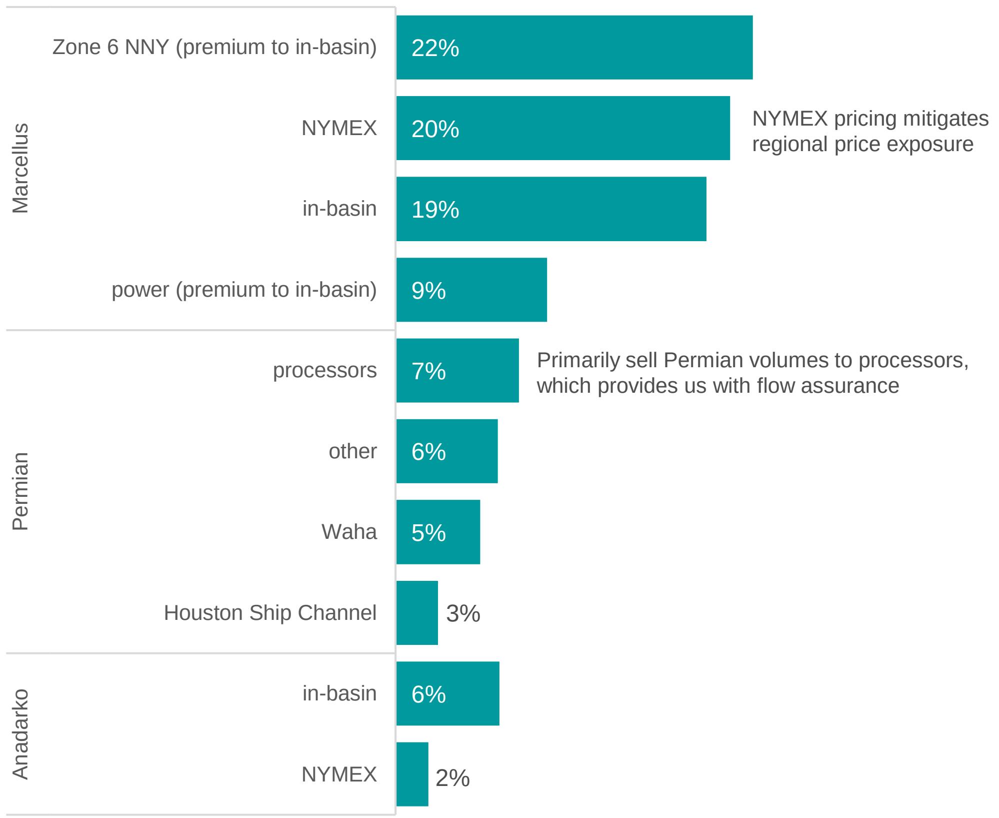
Midstream/Power Capability in our Permian Assets



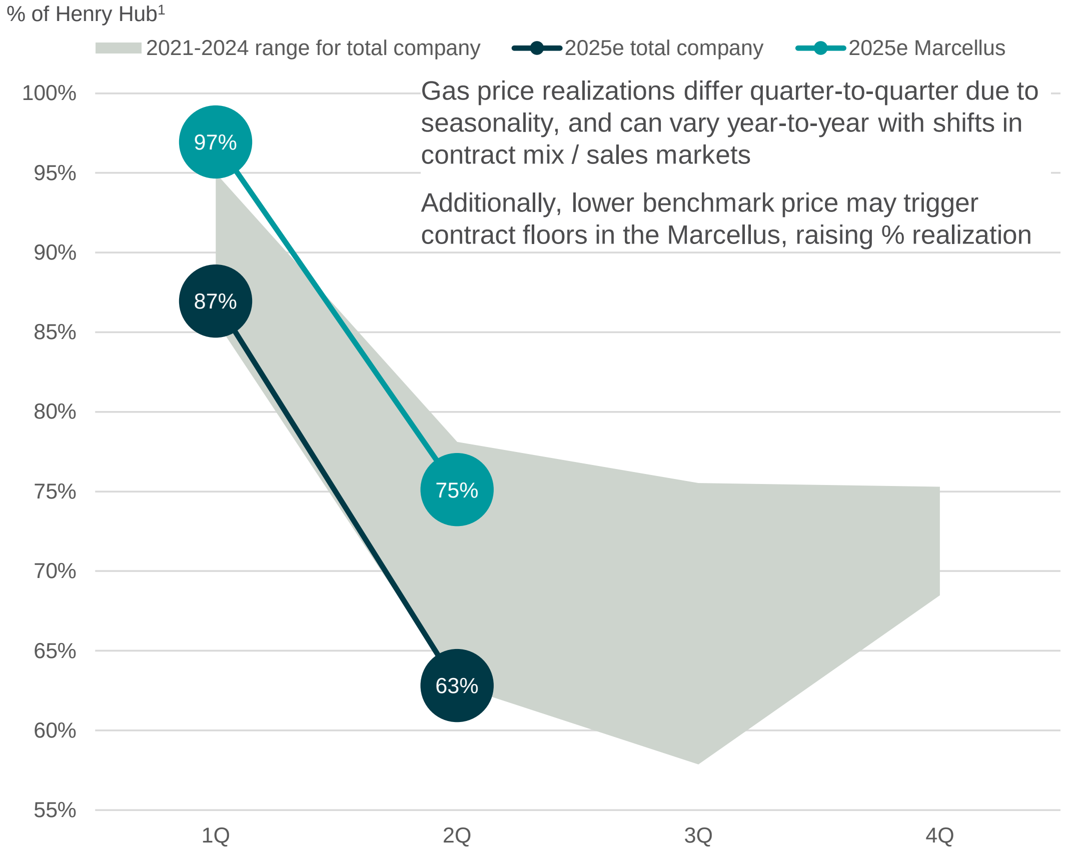
	Culberson and Reeves Counties	Lea County Bolt-on Acquisition	Cost Savings
Saltwater Disposal *Allows for substantial recycling of produced water back into our completion operations*	• Over 300 miles of pipeline, reduces surface storage & potential spills • In 2024, Coterra's Permian completions used 89% recycled water, up 3% from the previous year, facilitated by our SWD assets	• ~120 miles of pipeline • Expect to recycle ~50% of water on acquired assets in 2025 (previously forecasted at ~40%)	**30-60% per barrel cost savings** *vs. using third-party water*
Electric Grid *Plugging directly into ERCOT, rather than relying on diesel- or natural gas-powered generators, provides significant cost savings*	• >200 miles of electrical distribution powerlines • 3 substations with total capacity of 260 MW • Fully powers e-compression (70 MW), full-time e-fleet in Culberson (33 MW), wells & facilities (30 MW), and 3-4 e-rigs (3 MW)	• Investigating power grid opportunities for future years • Using natural gas power generation while we wait on grid availability	**~$50/ft** *e-frac vs. using diesel, @ recent spark spread*
Gas Gathering System *Brings expenses in-house, enhances netbacks and economics*	• Over 600 miles of pipeline • Throughput capacity > 1.2 Bcfd • Takeaway supported by 20 offload points & offers competitive pricing	• ~125 miles of pipeline • Throughput capacity ~130 mmcfd	

Diversified Gas Marketing Portfolio

2025 Estimated Natural Gas Sales Markets



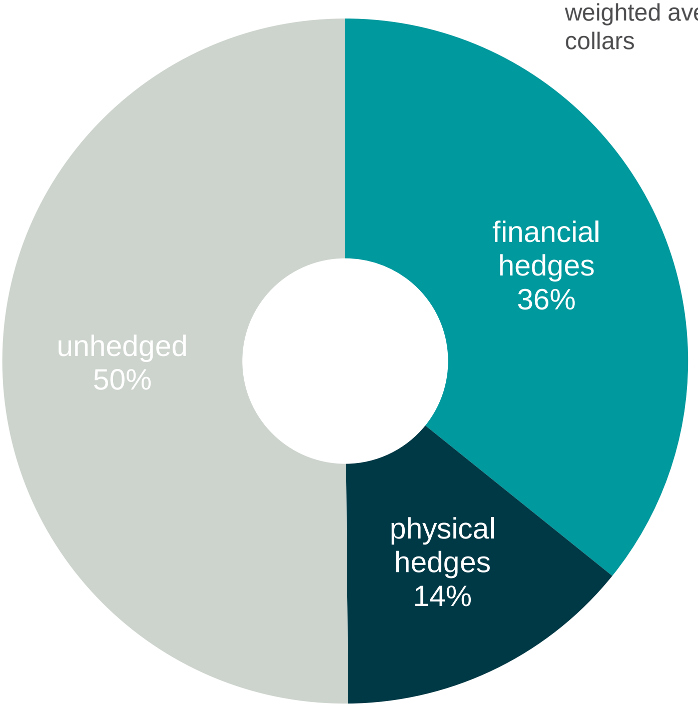
2021-2025e Natural Gas Price Realization Range[1]



2025 Hedge Summary

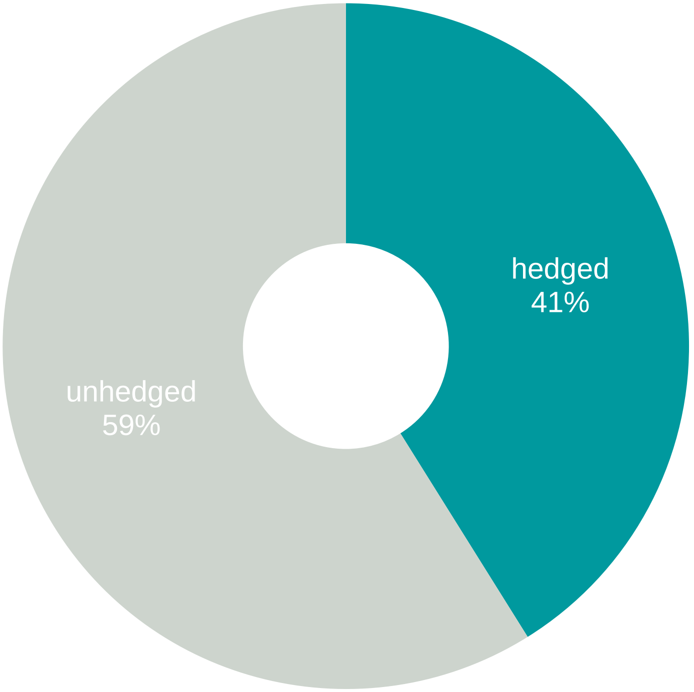
2Q25e-4Q25e

Remaining 2025e gas volumes ~50% hedged



$3.01/MMBtu & $4.82/MMBtu
weighted average floor & ceiling price on NYMEX collars

Remaining 2025e oil volumes >40% hedged



~$62/bbl & ~$79/bbl
weighted average floor & ceiling price on collars

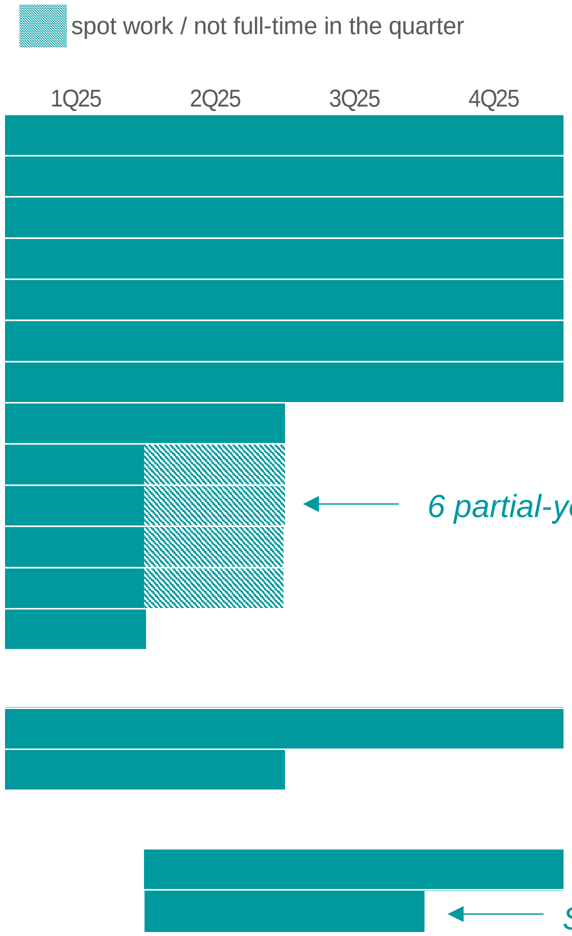
~$69/bbl
weighted average on swaps

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 (mmcfd)	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			
	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					$42			
Cash Flow & Investment	Commodity price assumptions:													
	WTI ($ 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

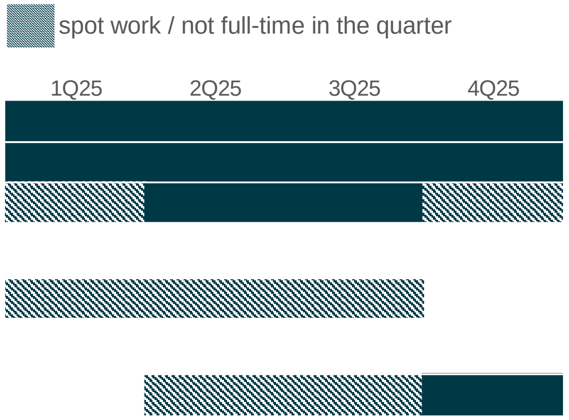
Rig Activity



6 partial-year rigs average to a total of ~9 Permian "full-year" rigs

Second spot rig provides optionality in the Marcellus; should macro conditions warrant, could increase capex by an incremental ~$50mm

Crew Activity



Note: Charts depict expected activity, not contract tenor. We have a mix of multi-year contracts, annual contracts, quarter-to-quarter, and pad-to-pad contracts

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[1]	$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[2]	$0.10	$0.05 - $0.08 - $0.10	$0.15
	% effective tax rate			
	% cash tax rate[3]	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: ($ in millions)	31-Mar 2025
Cash flow from operating activities	$ 1,144
Changes in assets and liabilities	(9)
Discretionary cash flow	**1,135**
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(472)
Free cash flow	**$ 663**

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

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

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

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:	**March 31**	**December 31**						
($ in millions)	**2025**	**2024**	**2023**	**2022**	**2021**	**2020**	**2019**	**2018**
	Coterra				Combined Cabot + Cimarex			
Net income	$ 1,285	$ 1,121	$ 1,625	$ 4,065	$ 1,158	$ 201	$ 681	$ 557
Plus (less):								
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	-	-	-
EBITDAX	**$ 3,821**	**$ 3,414**	**$ 3,928**	**$ 6,730**	**$ 2,242**	**$ 719**	**$ 1,412**	**$ 1,264**
Legacy Cimarex EBITDAX					1,005	935	1,460	1,558
Combined EBITDAX	**$ 3,821**	**$ 3,414**	**$ 3,928**	**$ 6,730**	**$ 3,247**	**$ 1,654**	**$ 2,872**	**$ 2,822**

	March 31	**December 31**						
($ in millions)	**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
Net debt to TTM EBITDAX	**1.1x**	**0.4x**	**0.3x**	**0.2x**	**0.6x**	**1.6x**	**1.0x**	**0.7x**

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
Pro forma acquisition-related expenses	13	-
Pro forma stock-based compensation	65	62
Adjusted Pro Forma EBITDAX (trailing twelve months)	**$ 4,663**	**$ 4,261**

	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
Net debt to Adjusted EBITDAX	**0.9x**	**0.4x**