COTERRA

3Q24 Earnings Presentation

October 31, 2024

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; 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; 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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Differentiated by Operational Excellence & Capital Discipline

Advantaged Assets and Operations

- Multi-basin portfolio provides commodity diversification and capital allocation optionality
- Top-tier acreage positions with deep inventory, estimated at ~15 years[1]
- Low-cost operator with corporate break-even[2] below \$50/bbl WTI & \$2.50/mmbtu HH

Operate Responsibly

- Published Sustainability Report in August 2024
- Reducing emissions with engineered solutions
- Executive & employee compensation tied to emissions reduction metrics
- Joined the United Nations Environment Programme's Oil & Gas Methane Partnership 2.0 (OGMP 2.0), a framework dedicated to achieving reliable methane emission measurement, reporting, and mitigation

Disciplined Investment

- Expect to reinvest 50-70% of cash flow at mid-cycle prices
- Allocate capital to the highest-returning projects
- Ability to pivot total investment & region allocation when macro conditions fundamentally change
- Fortress balance sheet

Return Value

- Committed to sustainably growing base dividend over time
- Minimum 50%+ return of annual Free Cash Flow through base dividends and buybacks
- \$2.0 billion share repurchase authorization, with \$1.2 billion remaining as of September 30, 2024[3]

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Note: See appendix for non-GAAP reconciliations and definitions. 1) Assumes average 2024e-2026e footage and \$75 WTI & \$3.75 Henry Hub. 2) Meaning FCF covers base dividend for multiple years. 3) Share repurchases shown are on cash basis, which excludes 1% excise tax and any shares that settled after the quarter-end.

High-Quality, Long-Life, Diversified Asset Portfolio

Multi-Basin Portfolio

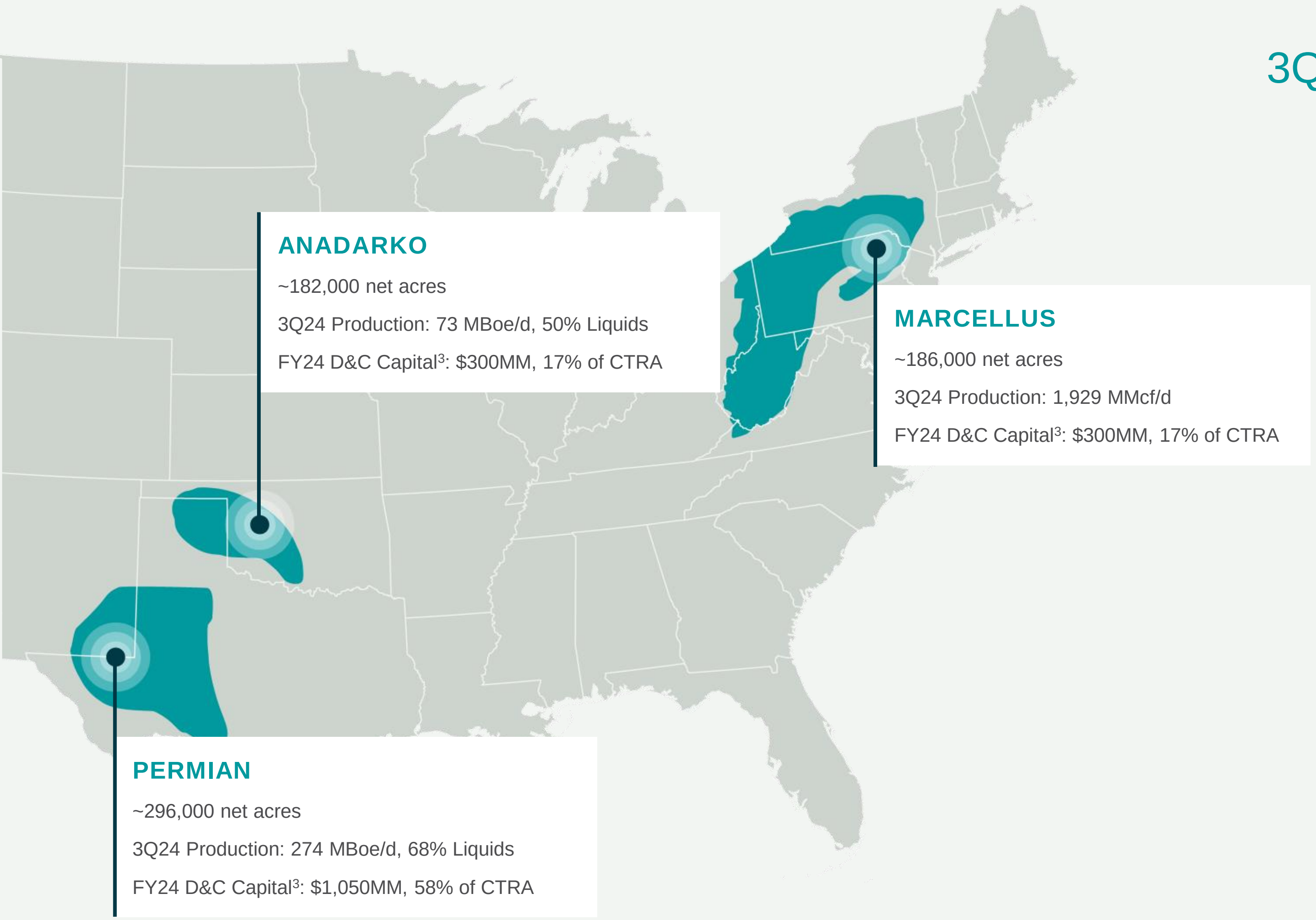
provides commodity diversification and capital allocation optionality

Top-Tier Acreage Position

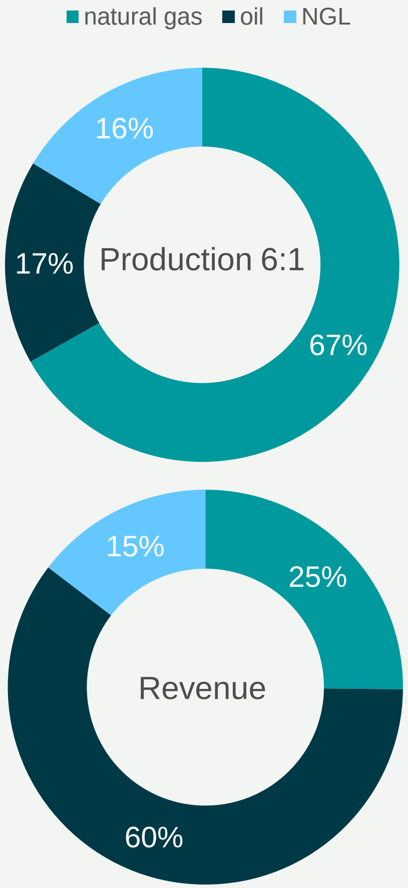
with deep inventory, estimated at ~15 years[1]

Low-Cost Operator

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



3Q24 Commodity Splits



1) Assumes average 2024e-2026e footage 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

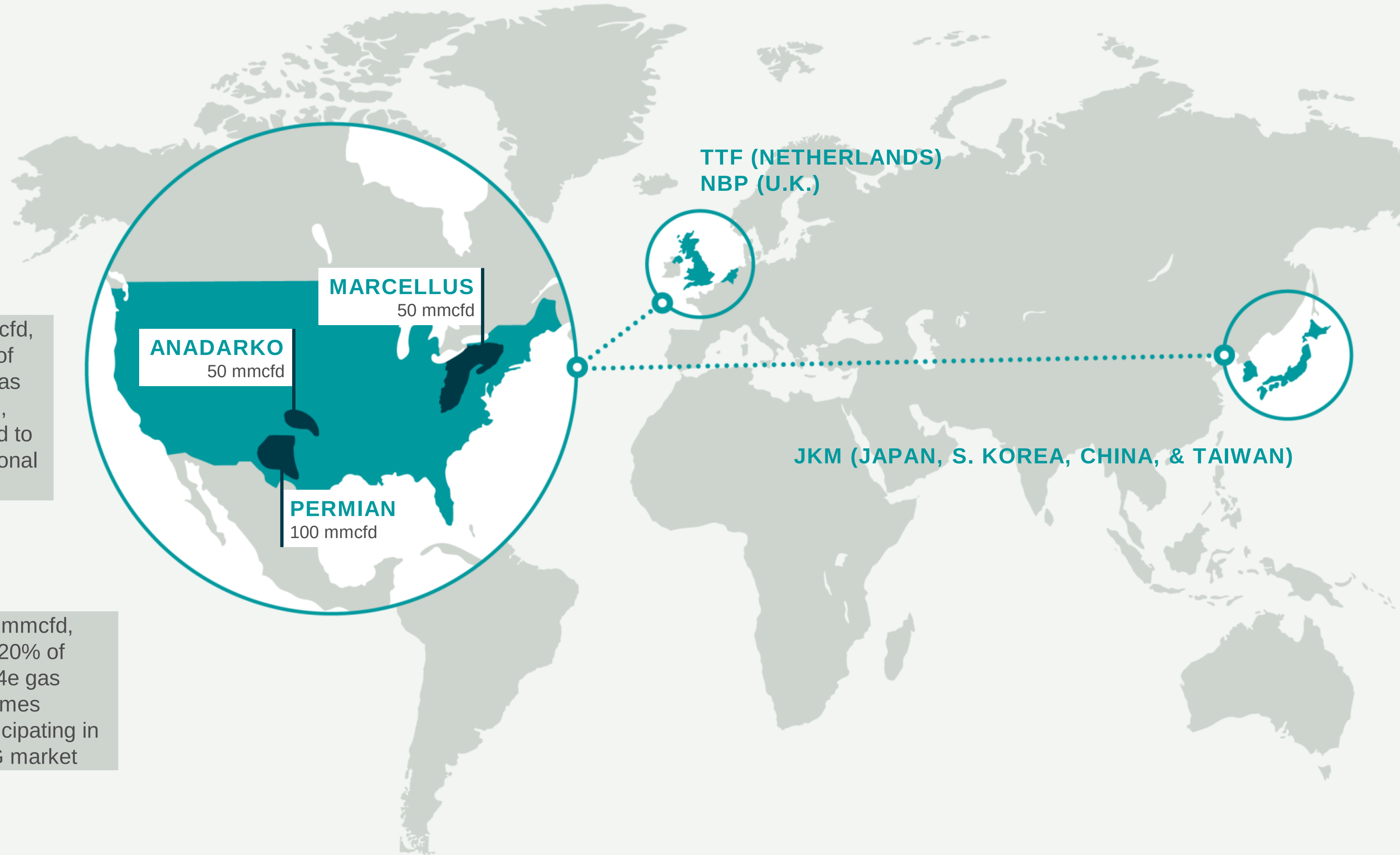
Diversifying Gas Portfolio with New LNG Contracts

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, or ~7% of 2024e gas volumes, to be tied to international pricing

550 mmcfd, or ~20% of 2024e gas volumes participating in LNG market



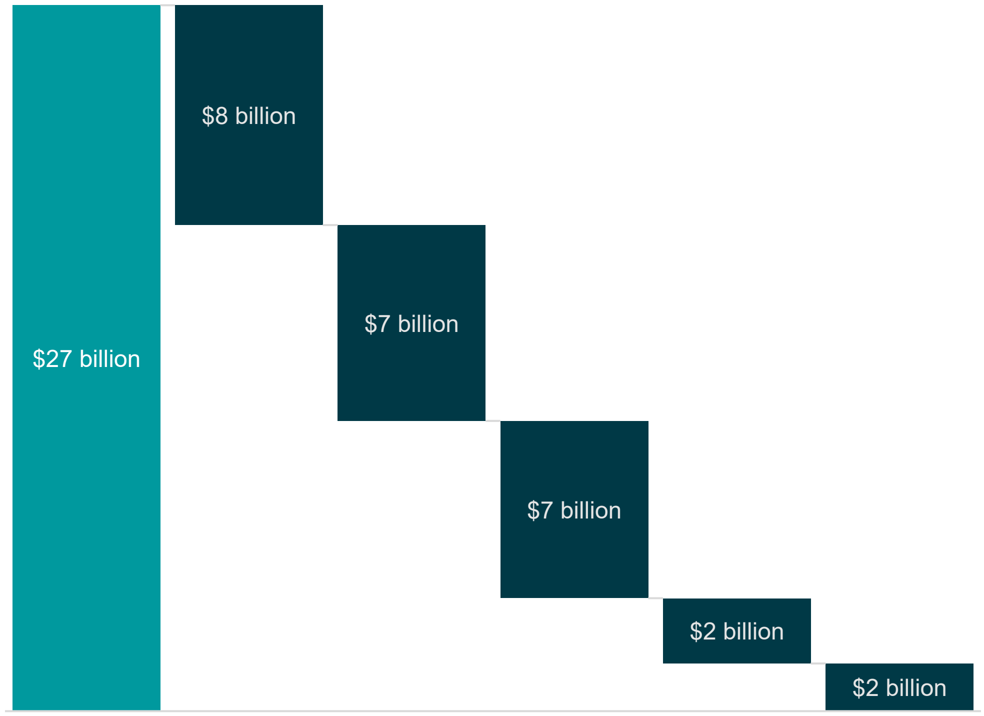
1) Facility is operating.

Long Runway of High-Quality Inventory

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

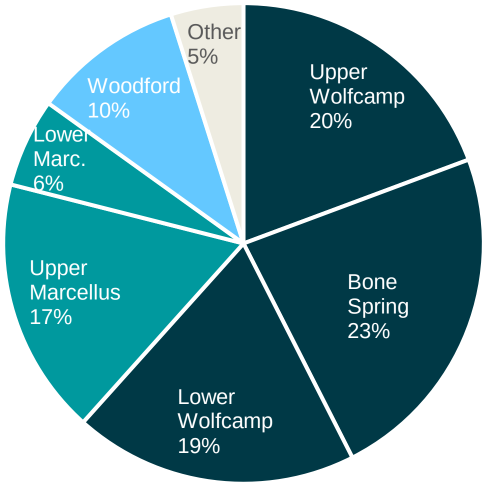
~$27 billion of Economic Capex Opportunities

estimated capex by PVI_{10} bucket:



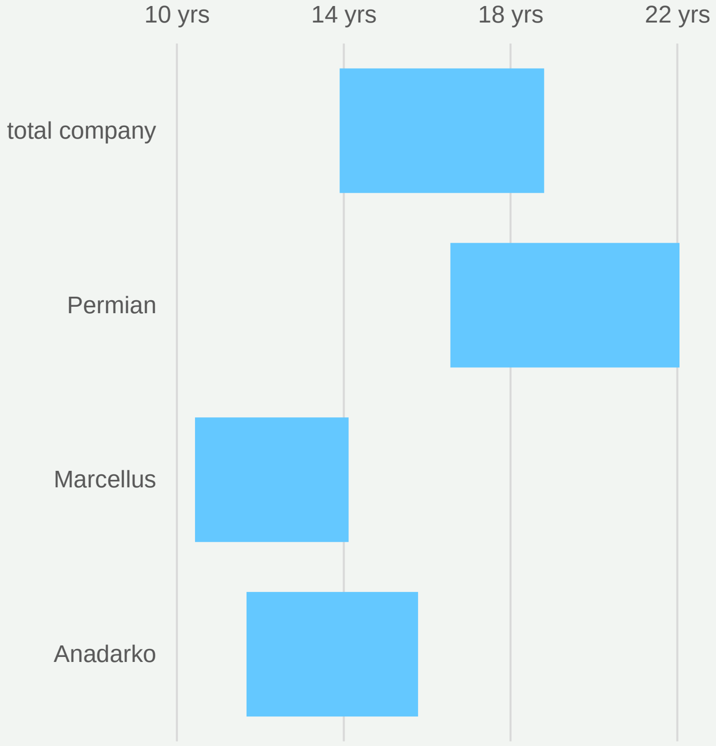
~$25bn, or ~95%, of capex is expected to generate 1.3x PVI_{10} or better

estimated capex by formation – Total Inventory:



Implied Inventory Duration[1]

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



Note: Estimates as of February 2024. See appendix for non-GAAP reconciliations and definitions, and other defined terms. 1) Calculated midpoints based on average 2024e-2026e footage.

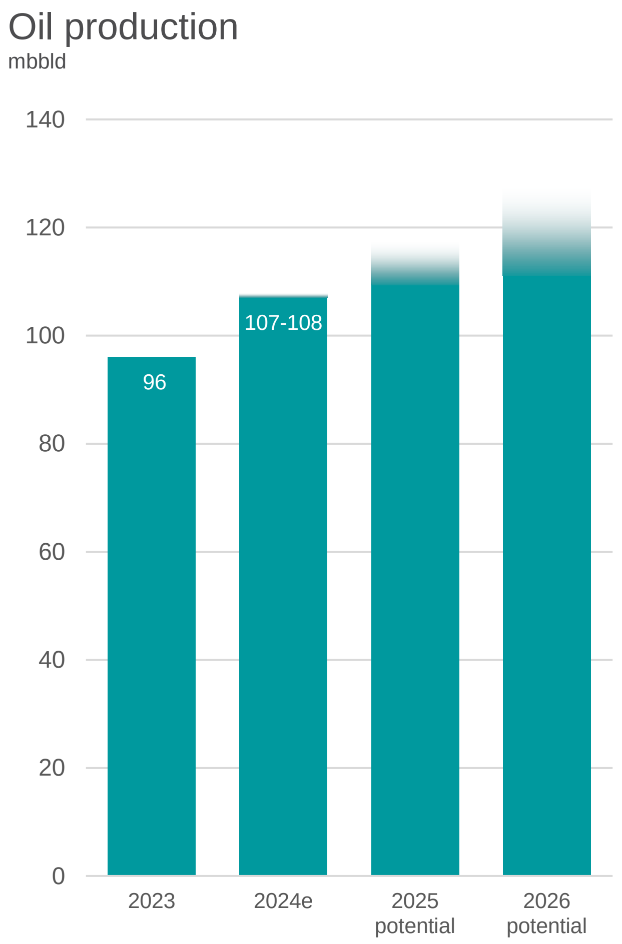
Executing on our Strategy

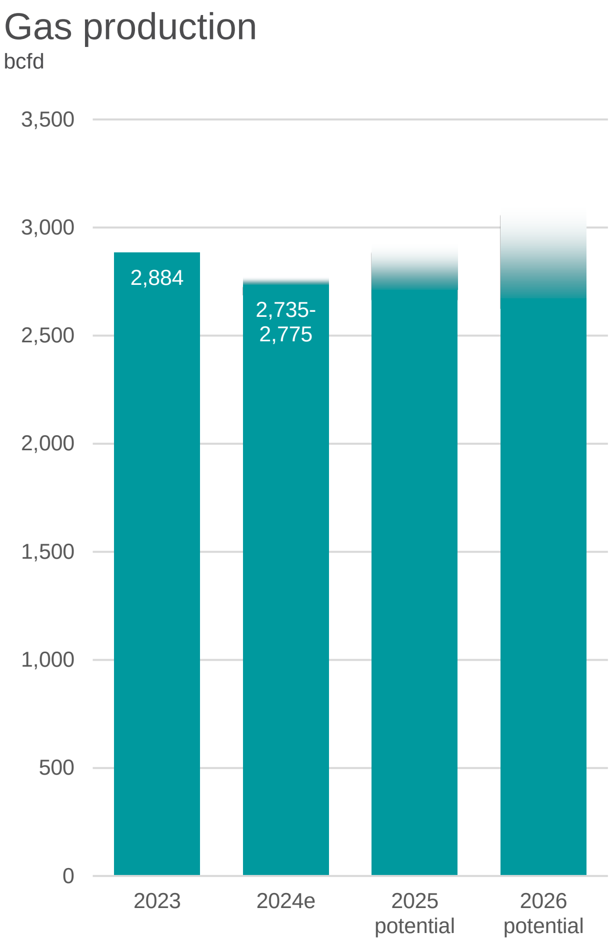
Beat & Raise	**3Q24 oil +1% | gas +2% | BOE +3%** Beat vs high-end of 3Q24 guidance	**2024 oil guidance +0.5%** Raised 2024 oil production guidance +0.5% at the midpoint vs August guidance and +5% at the midpoint vs initial February guidance
Expect 2024 Capex Down & Volumes Up YoY	**$1.75-1.85 billion** Expected 2024 capex; down 14% YoY at the mid-point, driven by deflation, Permian efficiencies, and lower Marcellus activity	**oil +12%** Expect 2024 oil volumes +12% YoY, at the mid-point; expect roughly flat BOE production
Delivering on Base Dividend	**$0.84 per share** Annualized 3Q24 declared dividend of $0.21 per share; +5% YoY	**3.5% yield** Based on annualized 3Q24 declared dividend and $24.13 share price as of 10/30/24
Returning Value to Shareholders	**100% of YTD24 FCF** Returned to shareholders via declared base dividends and buybacks[1]	**50%+ of annual FCF** Return to shareholders via base dividends and buybacks[1]
2024e-2026e Outlook Maintained	**$1.75-1.95 billion** Expected average capex range for 2024-2026	**5%+ oil CAGR** Expected over 2024-2026, with 0-5% BOE CAGR

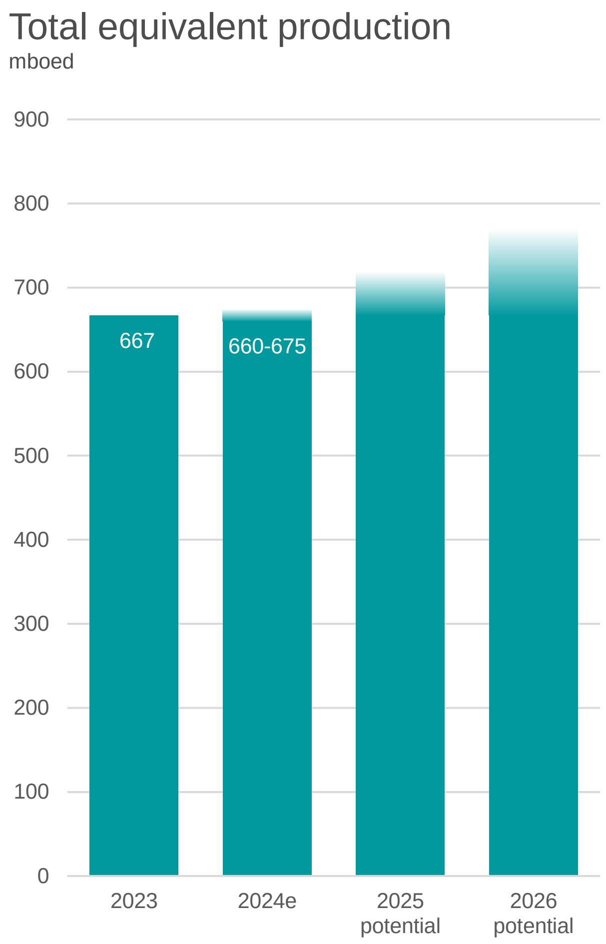
Note: Capex discussed is incurred or expected to be incurred; not cash basis. See appendix for non-GAAP reconciliations and definitions. 1) cash basis, excluding 1% excise tax and shares that settled after quarter-end.

3-Year Outlook: Optionality Across Diversified Portfolio

Expect 0-5% annual growth on total equivalent production and 5%+ annual growth on oil production







$1.75-1.95 billion

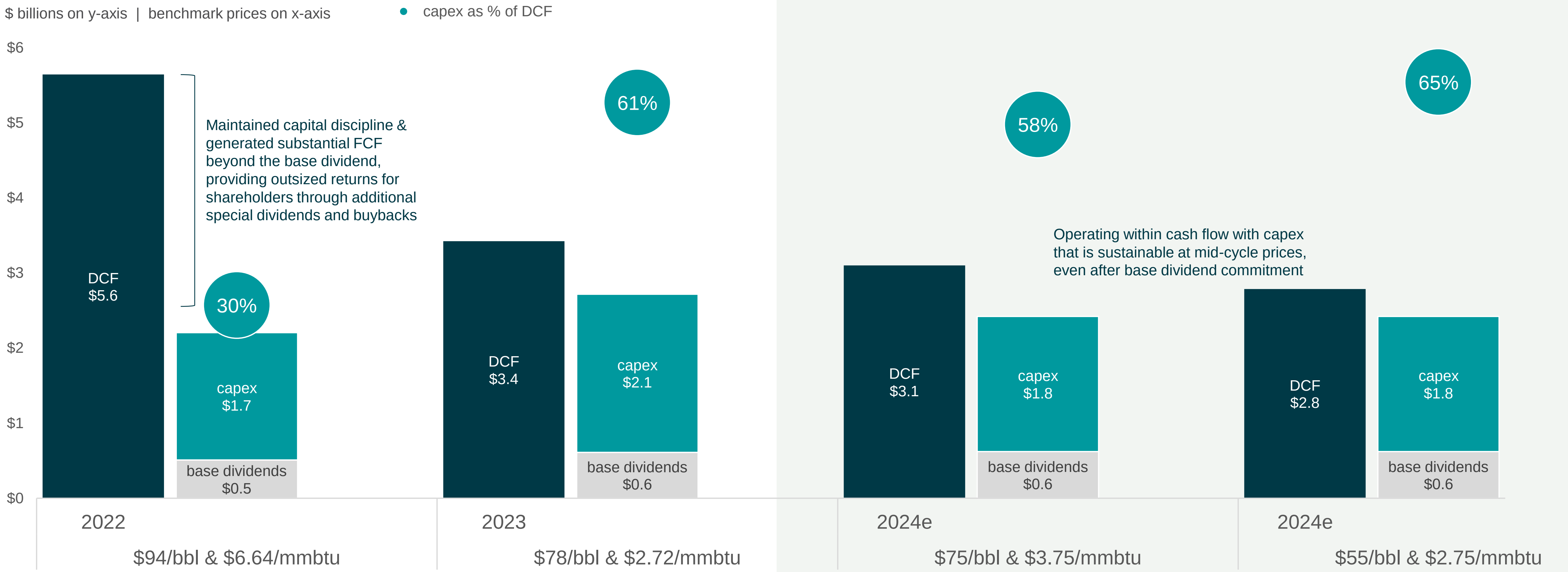
Expected average capex range for 2024-2026

5%+ oil CAGR

0 to 5% mboed CAGR

Committed to Capital Discipline & Free Cash Flow Generation

Expect to reinvest ~50-70% of cash flow at mid-cycle prices



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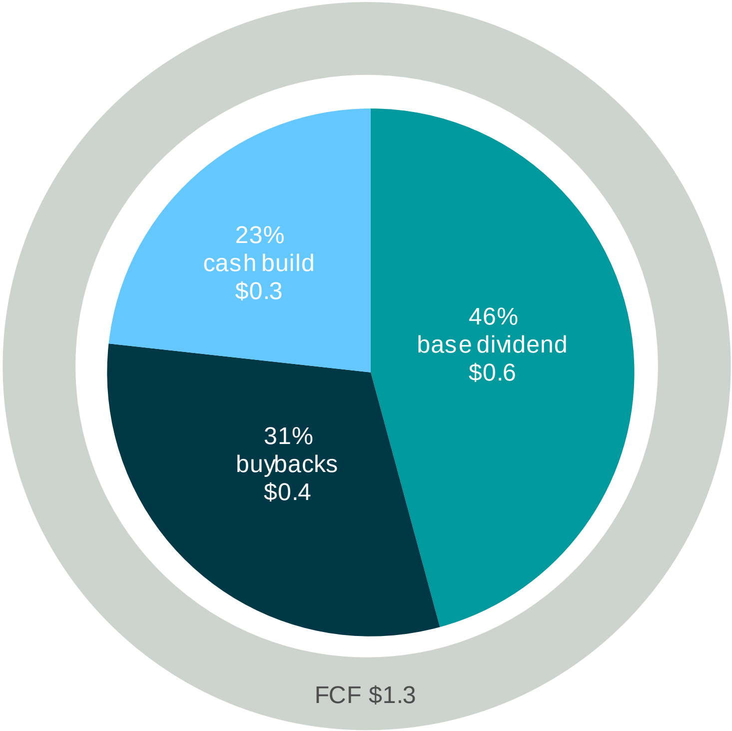
Note: See appendix for non-GAAP reconciliations and definitions. Capex shown is incurred or expected to be incurred (non-cash basis), with 2024e at mid-point of guidance. Dividends shown are declared dividends within the year, not cash paid. 2024e base dividends = YTD24 declared dividends of $466mm + share count, per cover of 3Q24 10Q * $0.21/sh (for remaining quarter of the year). Future dividends are subject to board approval. Flat price decks are for 4Q24 while actual commodity prices are reflected for YTD24.

Committed to Returning Value

$ billions | Percentages shown are shareholder returns as percentage of FCF

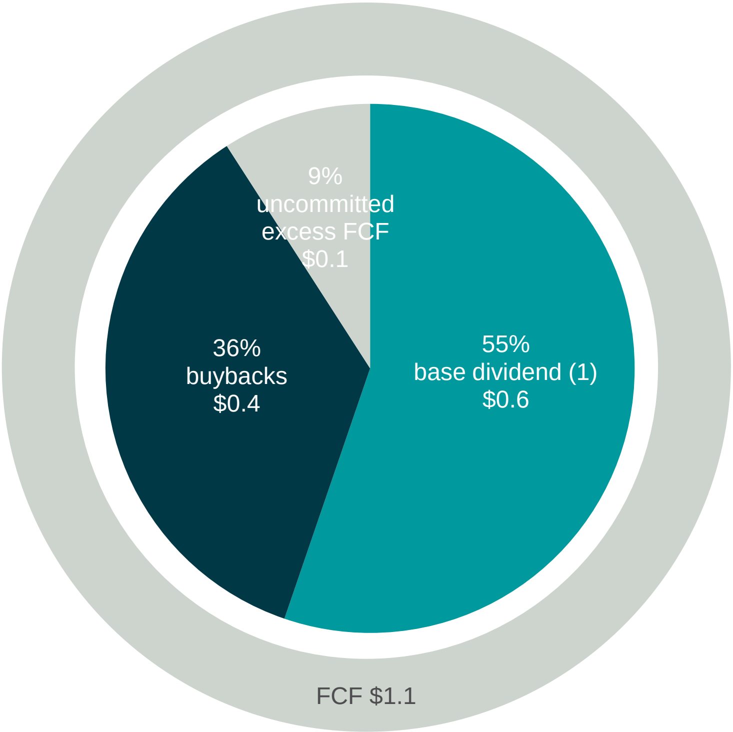
2023 FCF $1.3bn



- Returned 77% of FCF to shareholders with dividends & share repurchases

2024e FCF $1.1bn

see appendix for commodity price assumptions

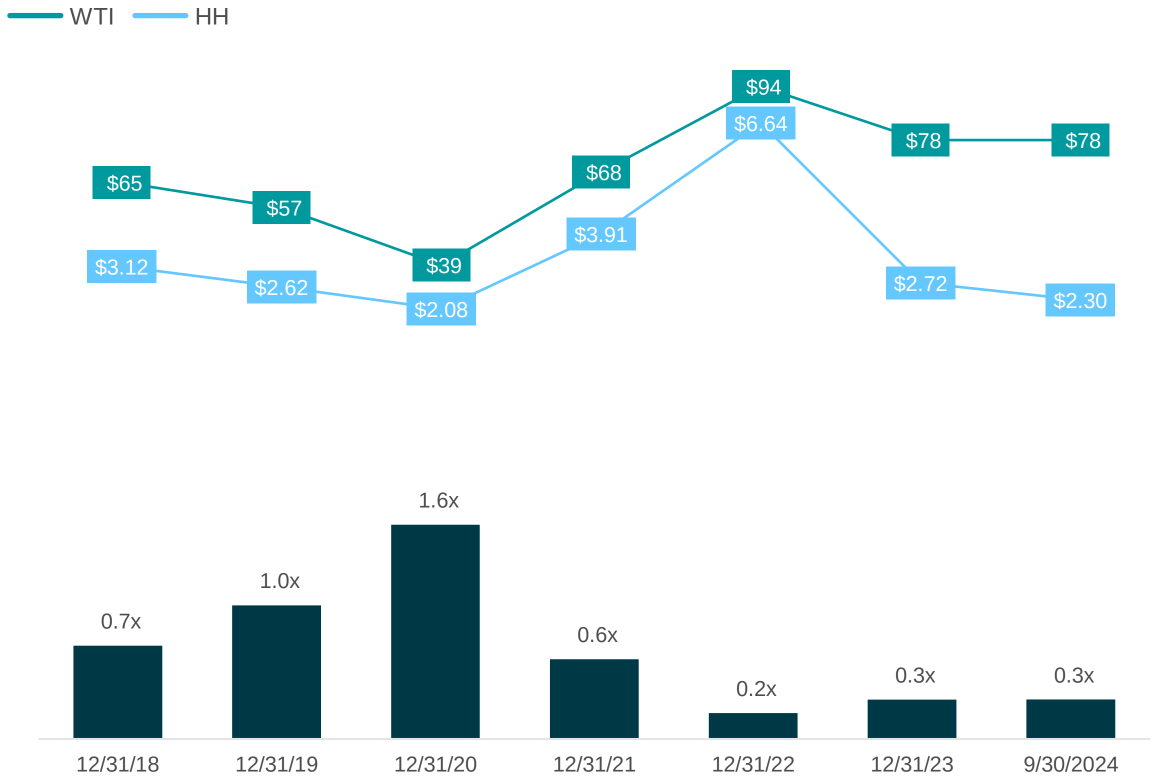


- Uncommitted excess FCF available for buybacks and cash build
- $2.0 billion share repurchase authorization with $1.2 billion remaining as of September 30, 2024

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.1) base dividend = YTD declared dividends of $466mm + share count, per cover of 3Q24 10Q * $0.21/sh (for remaining quarter of the year). Future dividends are subject to board approval.

Prioritizing Financial Flexibility

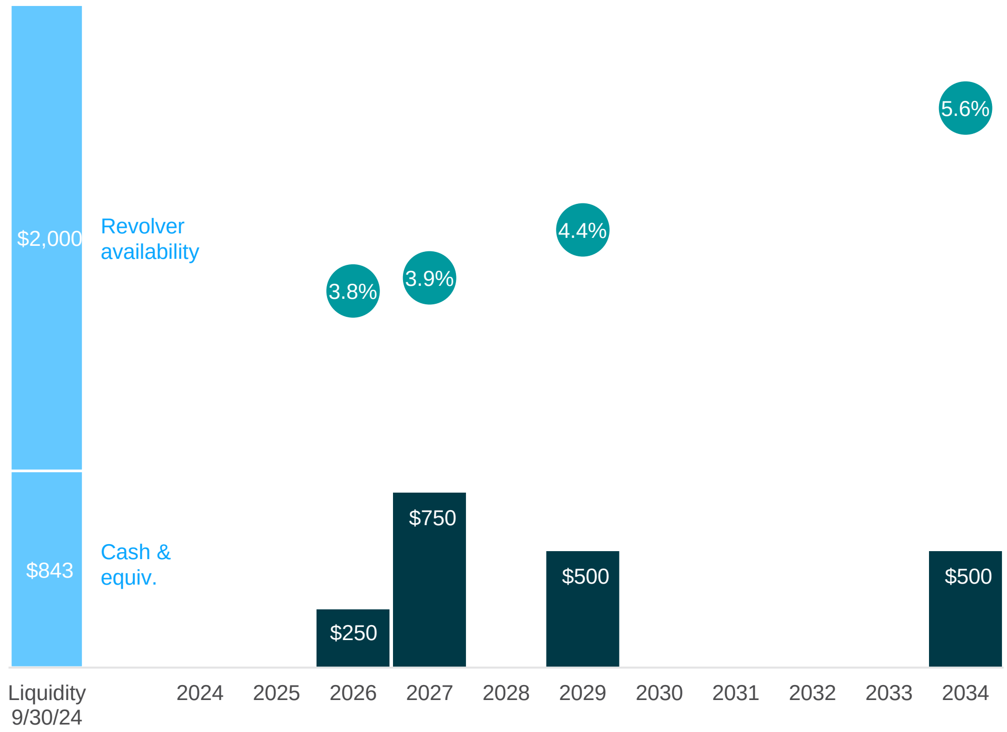
History of Conservative Net Leverage



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
Substantial liquidity

Note: See appendix for non-GAAP reconciliations and definitions. Commodity prices are trailing-twelve-month benchmark prices.

Permian Asset Overview – 2024 Operational Outlook

$1,050 million
Mid-point D&C CapEx

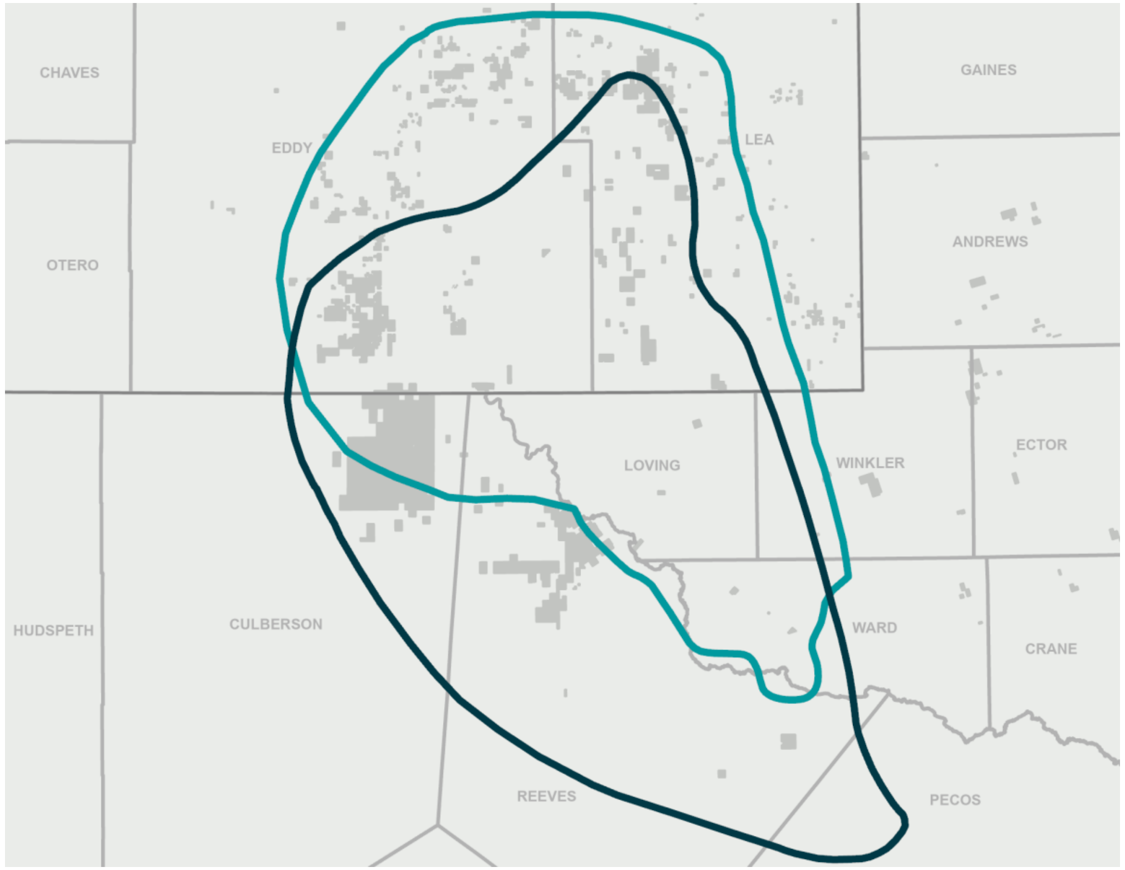
9,600'	-12% from 2023 guidance of $1,200/ft $1,050	80-90
Avg. Lateral Length[1]	Avg. Well Cost per Foot[1]	Net Wells Online

1) Of operated wells expected to come online within the year. Average lateral length * average well cost per foot * mid-point net wells online = TIL D&C capex, not annual D&C capex. Spend for a well is incurred over a period of 6-10 months, which does not necessarily fall within a single calendar year. D&C Capital = Drilling & Completion Capital, which includes drilling, completion, facilities and post-completion capital

Permian Asset Overview

Targeting Prolific Wolfcamp & Bone Spring

Coterra Acreage ■ Wolfcamp ■ Bone Spring



Notable Row Projects in Culberson County

Windham Row Phase 1	
51	gross Upper Wolfcamp wells
6	gross Harkey wells, co-developed
50%	working interest
1Q25	final wells expected online

Windham Row Phase 2	
16	gross Harkey wells, overfill
50%	working interest
3Q24	began drilling
1Q25 - 2Q25	wells expected online

Barba-Row Phase 1	
20	gross Upper Wolfcamp wells
8	gross Harkey wells, co-developed
80%	working interest
3Q24	began drilling
2H25	wells expected online

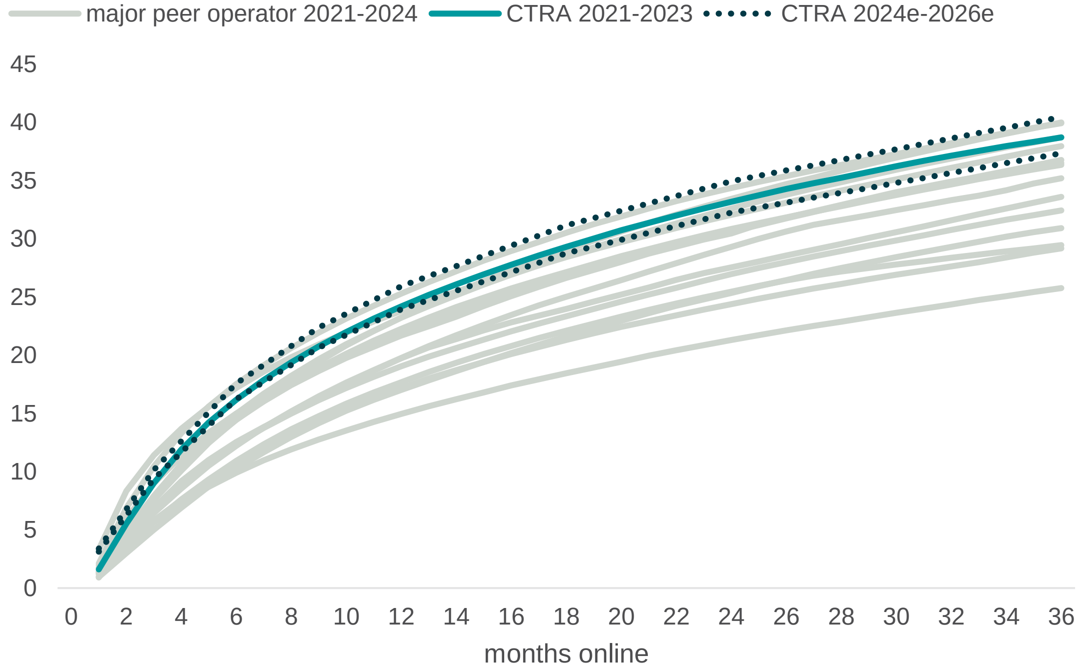
Bowler Row	
42	gross Upper Wolfcamp wells
20	gross Harkey wells, co-developed
50%	working interest
1Q25	begins drilling
4Q25 - 2026	wells expected online

Note: wps = wells per section.

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

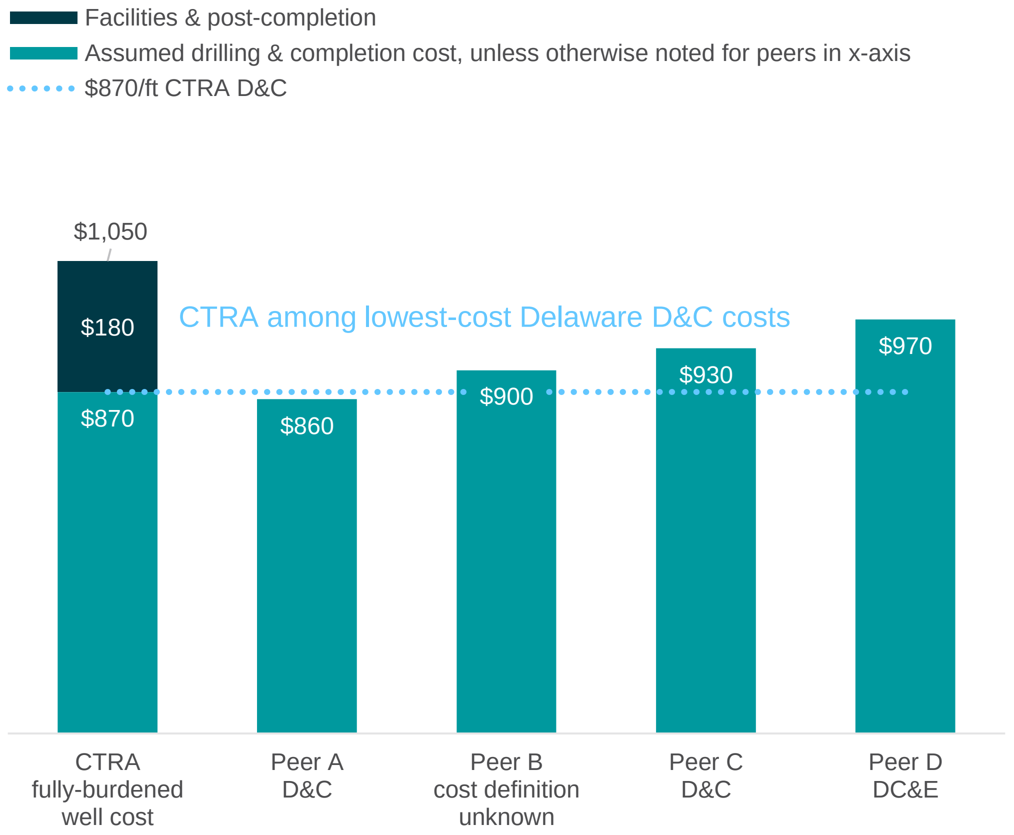
Delaware Productivity[1]

Cumulative Oil per Lateral Foot



- Productivity will differ from year to year, depending on project selection & other operational decisions
- Generally, our Permian program will be ~2/3 Texas and ~1/3 New Mexico due to our large, contiguous position in Texas
- Our program continues to benefit from optimized spacing and completion design decisions that generate resilient returns at various commodity prices

2024e Delaware D&C Well Costs per Foot[2]



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1) Source: Enverus Prism for historical data and internal forecasts for future estimates. 2) Sourced from recent company disclosure. CTRA D&C cost estimate based on operated wells with expected frac end-date in 2024.

CTRA Fully-Burdened Leading Edge Delaware Well Cost Estimates

$ per foot

Encouraging Bone Spring Results in Lea County

Promising Inventory Runway for Bone Spring

Brought 16.7 net Bone Spring wells[1] online in Lea County this year

Successful initial test on 1st Sand with Dos Equis

- Drilled 2 wells this year in 1st Sand with outstanding results; early productivity in-line with initial Wolfcamp A results

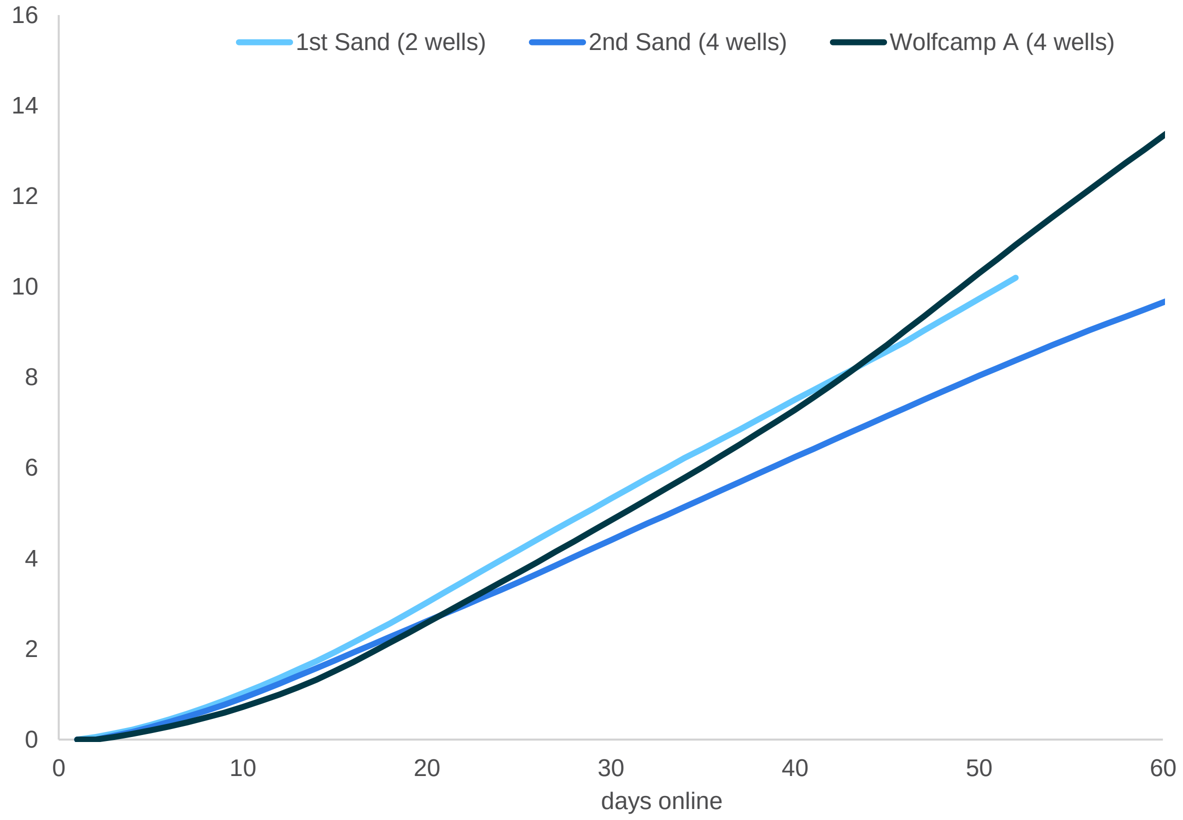
Comparable capital efficiency between Bone Spring & Wolfcamp

Multiple pay zones in Bone Spring for future inventory

- 4 wells per section in 1st sand, or 2nd shale
- Stack and stagger in 2nd sand at 7 wells per section

Oil Productivity on 2024 Dos Equis Project

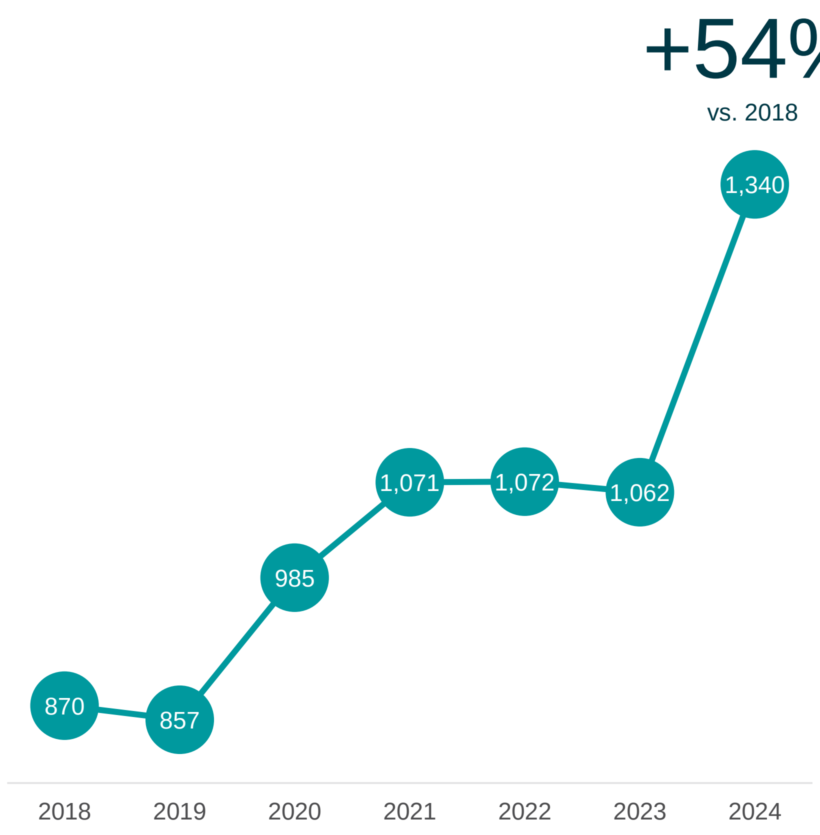
Cumulative Oil per Lateral Foot



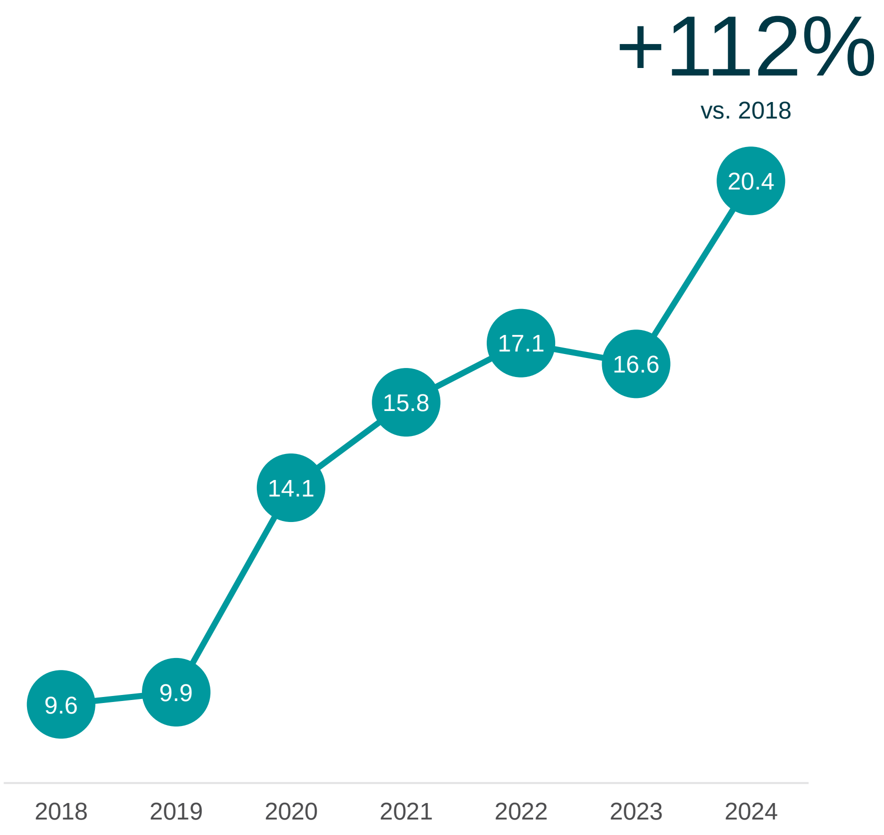
1) Including 4.7 net Harkey wells.

Ops Efficiencies in Lea County Bone Spring

Drilling Feet per Day[1]



Pump Hours per Day



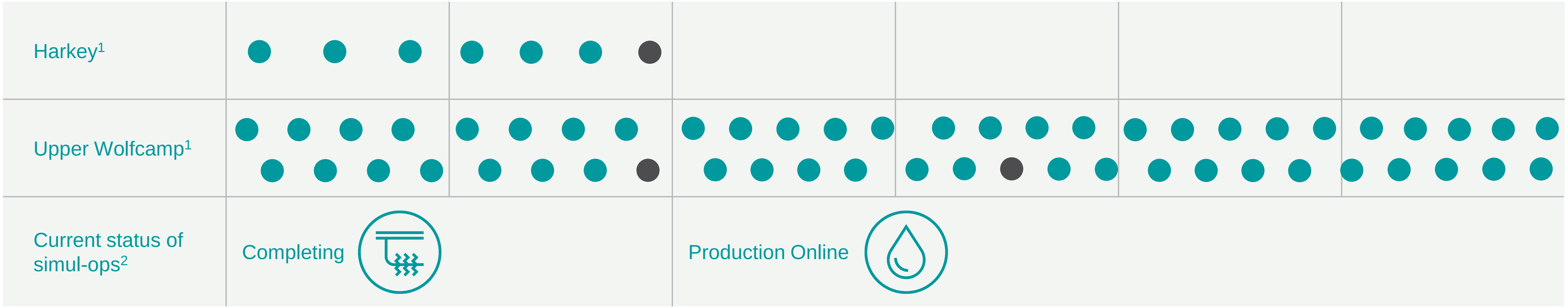
Improvement on rig & frac efficiency driven by

- Increased number of wells per pad
- Longer laterals
- Transition time reduction effort

1) Based on spud-date to total-depth-date.

Windham Row Project

57-well project across 6 drilling spacing units with 7-10 wells per section in Upper Wolfcamp & 3-4 wells per section in Harkey



Row projects allow for concentrated activity & simultaneous operations, which can reduce cycle times and costs

Project size will vary, but expect major row projects every 12-18 months

Windham Row status update

- To date, 36 of the 57 Windham Row wells have come online
- 10 additional wells, including 3 Harkey, are expected to come online through the end of the year
- The final 11 wells, including 3 Harkey, are expected online in early 1Q25
- Now plan to simul-frac ~80% of the project, up from 50%, due to success with the initial simul-frac test

Harkey additions

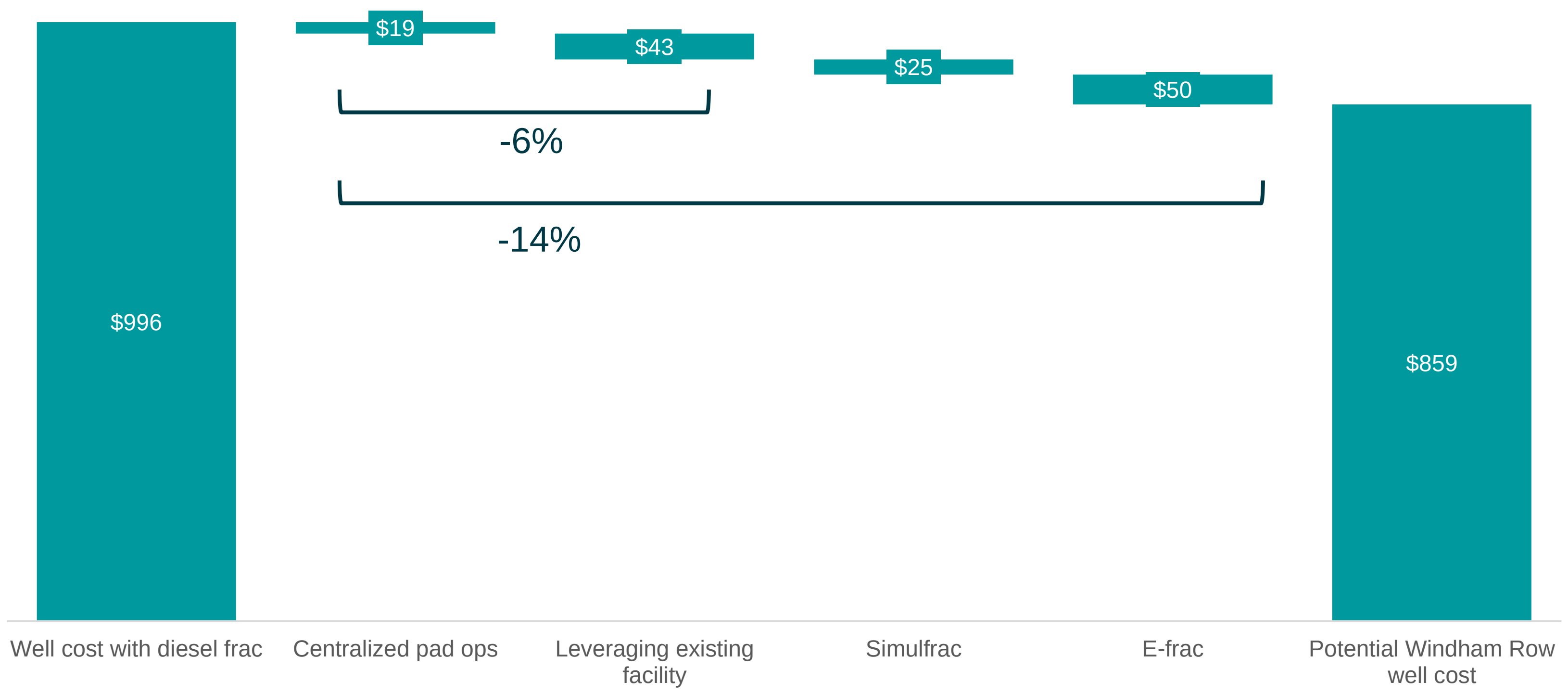
- Recent results from co-developed tests indicate it may be beneficial to co-develop Harkey
- Added 6 Harkey co-develop wells to the project without incurring additional infrastructure/facilities costs
- Windham Row Phase 2, comprised of 16 gross Harkey overfill wells, began drilling in 3Q24 and wells are expected online 1H25

1) Illustration depicts 3 existing wells, colored gray. 2) Status as of October 31, 2024.

Expect 5-15% Cost Savings on Windham Row

Average Culberson Well Cost

$ per foot



Centralized pad operations

- Reduces mobilization time for rigs & frac crews
- Maximizes pump hours per day with faster transition time between wells
- Minimizes infrastructure needed from well to facility

Reduced facilities & infrastructure needs

- Project leverages existing large, centralized facilities
- Project saves on pipeline and facility size, due to
  - staggered first production timing from simul-ops,
  - flexibility to co-develop and/or return to develop other benches later on, and
  - centralized pad operations

Simulfrac

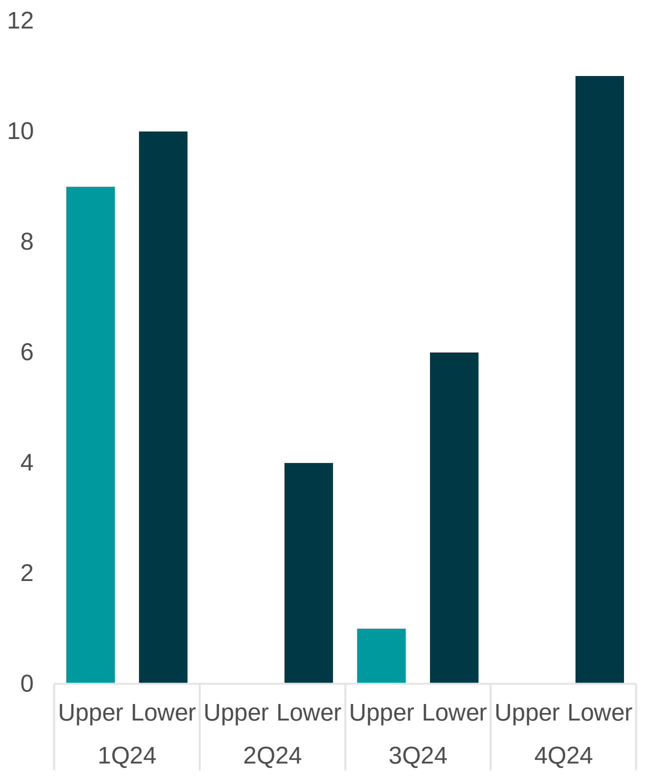
- Simulfrac allows for dual well completion with a single crew; faster timing driving down cost per foot
- Testing Simulfrac on 39 Wolfcamp and 6 Harkey wells

Marcellus Asset Overview – 2024 Operational Outlook

$300 million
Mid-point D&C CapEx

11,500’ Avg. Lateral Length for Upper[1]	**$980** Avg. Well Cost per Foot[1]	**40** Net Wells Online
9,360’ Avg. Lateral Length for Lower[1]	**$1,040** Avg. Well Cost per Foot[1]	

2024e Net Wells Online



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1) Of operated wells expected to come online within the year. Average lateral length * average well cost per foot * mid-point net wells online = TIL D&C capex, not annual D&C capex. Spend for a well is incurred over a period of 6-10 months, which does not necessarily fall within a single calendar year. D&C Capital = Drilling & Completion Capital, which includes drilling, completion, facilities and post-completion capital

Marcellus Asset Overview

Susquehanna County acreage leverages highly productive Marcellus

Coterra Acreage

Lower 2024 activity YoY

- In response to weak near-term natural gas macro, lowered 2024e Marcellus D&C capex by ~65% year-over-year
- Still have flexibility to increase capital and gas volumes over the next three years, as incremental demand from U.S. LNG facilities comes online

Managing gas volumes in response to price

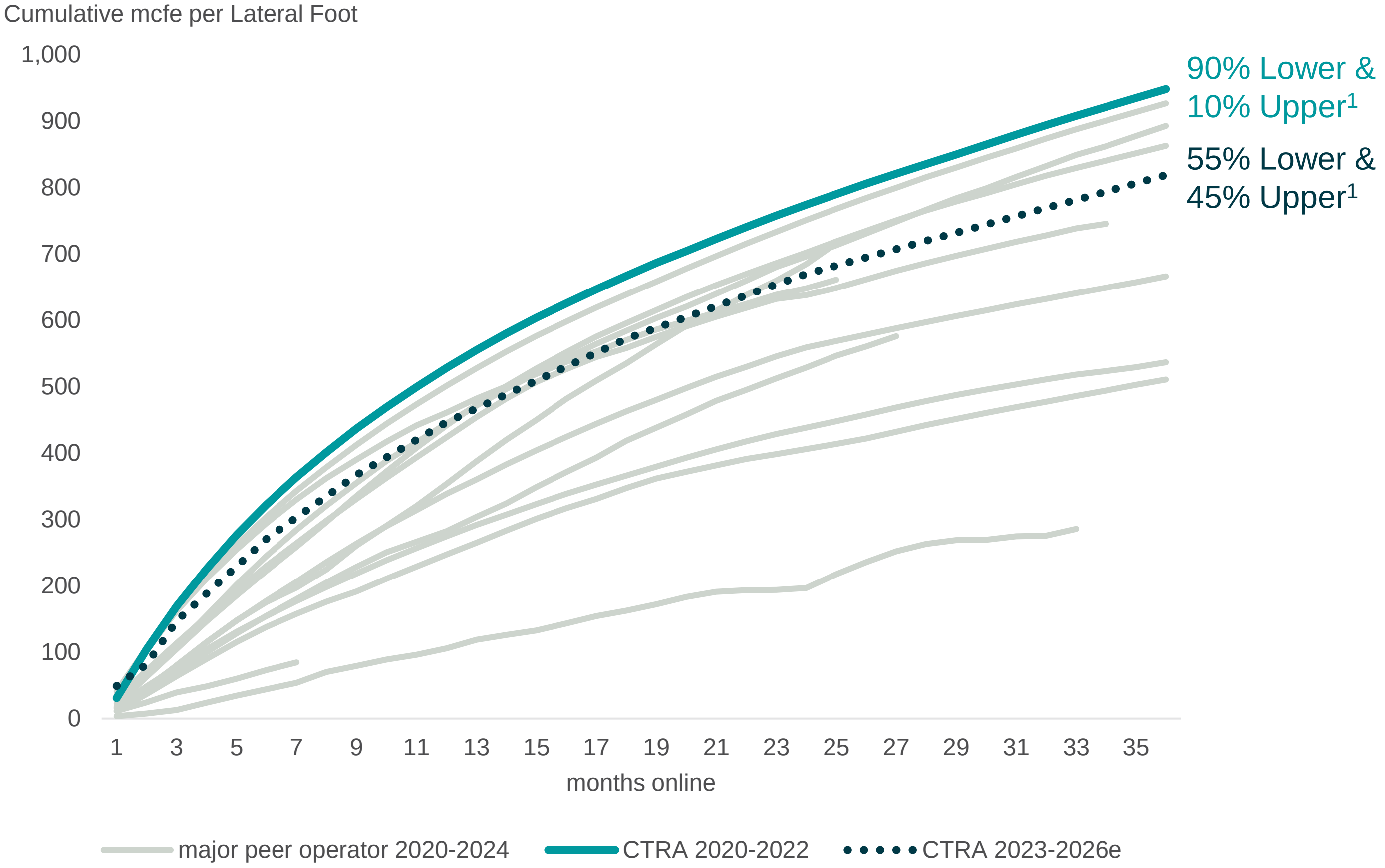
- Currently at zero drilling and zero completion activity
  - 11 Dimock wells are already completed and expected online in 4Q24
- Curtailing ~288 mmcfd of Marcellus volumes for the month of November
- Continue to monitor gas fundamentals and reserve the optionality to respond to signals on a month-to-month basis

Long-lateral capability

- Leased ~2,500 additional net acres in 2023, allowing for extended lateral length
- Targeting long-lateral development in 2024, with Lower Marcellus at 9,360’ and Upper Marcellus at 11,500’

Top-Tier Marcellus Producer

Marcellus Productivity



Peer-leading productivity driven by premier acreage position, in Northeast Pennsylvania

Productivity expected to trend downward slightly with introduction of Upper Marcellus

However, the Upper's lower $/ft costs are expected to drive capital efficient returns

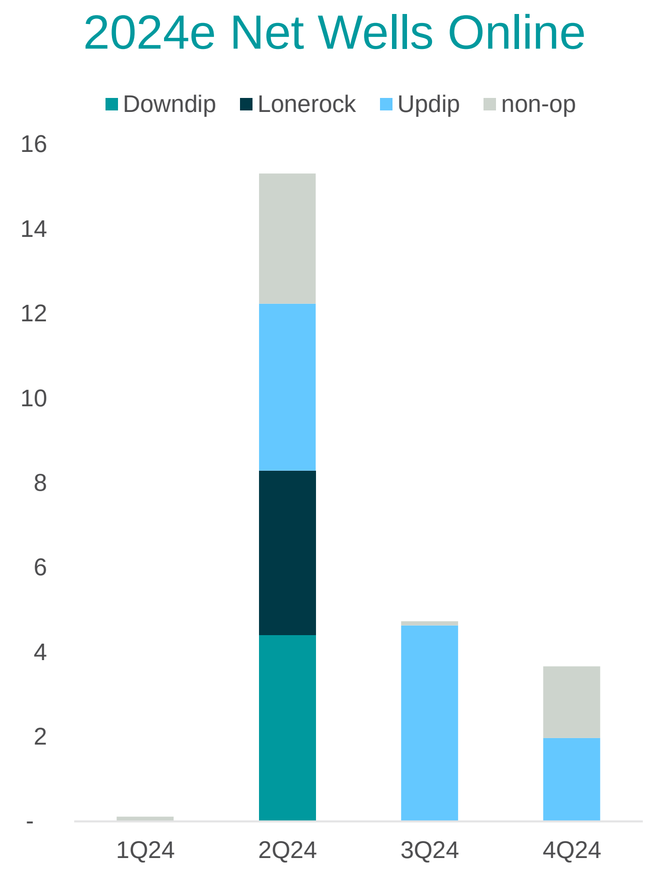
Source: Enverus Prism for historical data and internal forecasts for future estimates. 1) Based on total lateral footage.

Anadarko Asset Overview – 2024 Operational Outlook

$300 million

Mid-point D&C CapEx

9,760'	$1,250	21-27
Avg. Lateral Length[1]	-4% vs 2Q24 guidance of $1,300/ft Avg. Well Cost per Foot[1]	Net Wells Online

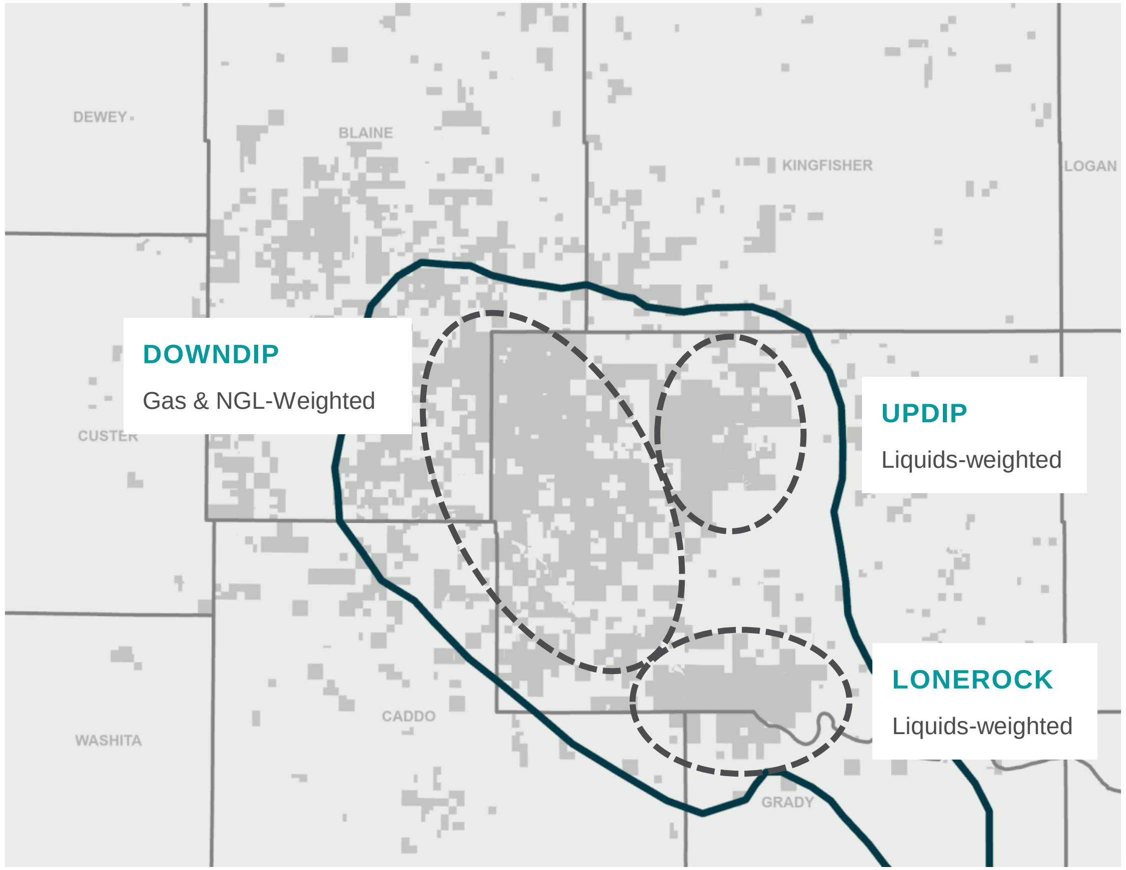


1) Of operated wells drilled and completed in 2024. Average lateral length * average well cost per foot * mid-point net wells online = TIL D&C capex, not annual D&C capex. Spend for a well is incurred over a period of 6-10 months, which does not necessarily fall within a single calendar year. D&C Capital = Drilling & Completion Capital, which includes drilling, completion, facilities and post-completion capital

Anadarko Asset Overview

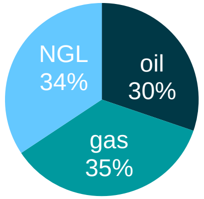
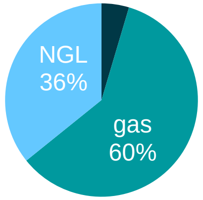
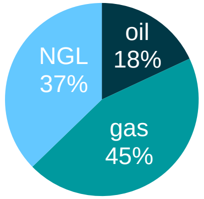
Increasingly important basin located near industrial & LNG export demand

Coterra Acreage · Woodford · Meramec



Major 2024 Anadarko projects

Nearly doubled D&C spend year-over-year, driven by competitive returns on recent projects

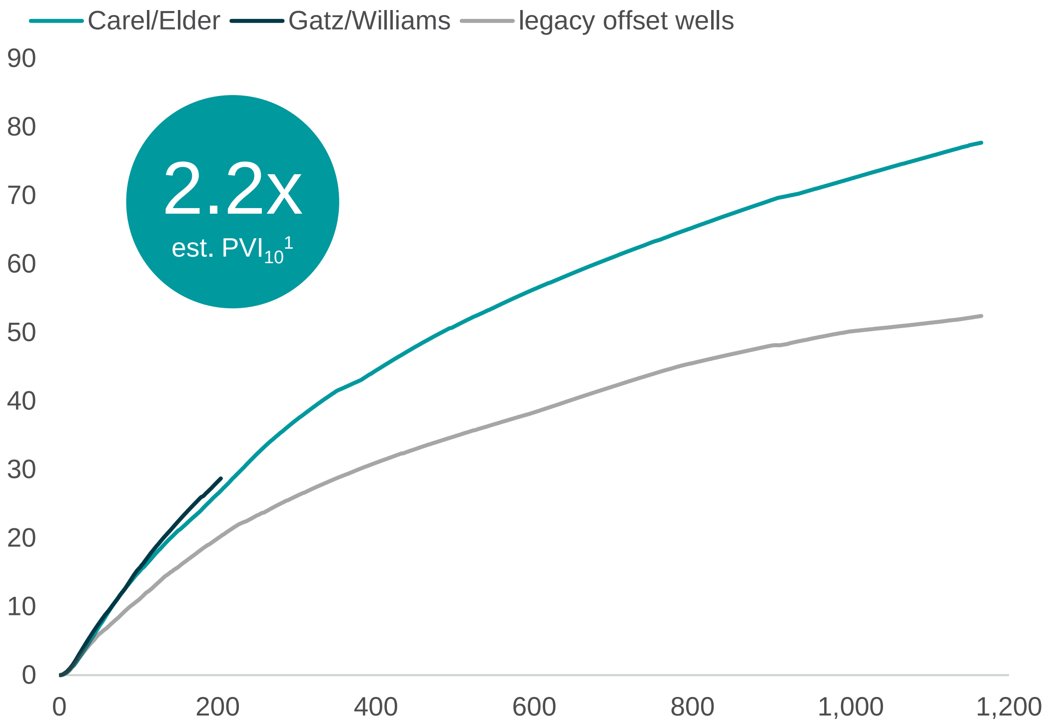
Online	Project name	Well count	Area	Estimated 60-month production mix at 6:1
April 2024	Gatz	3.9 net (4 gross)	Lonerock (Woodford)	
May 2024	Marilyn	4.4 net (5 gross)	Downdip (Woodford)	
June-July 2024	Maxine	6.7 net (7 gross)	Updip (Primarily Woodford, 1 Meramec)	

Recent Anadarko Projects are Outperforming Legacy Offsets

Wider spacing driving improved productivity & higher returns

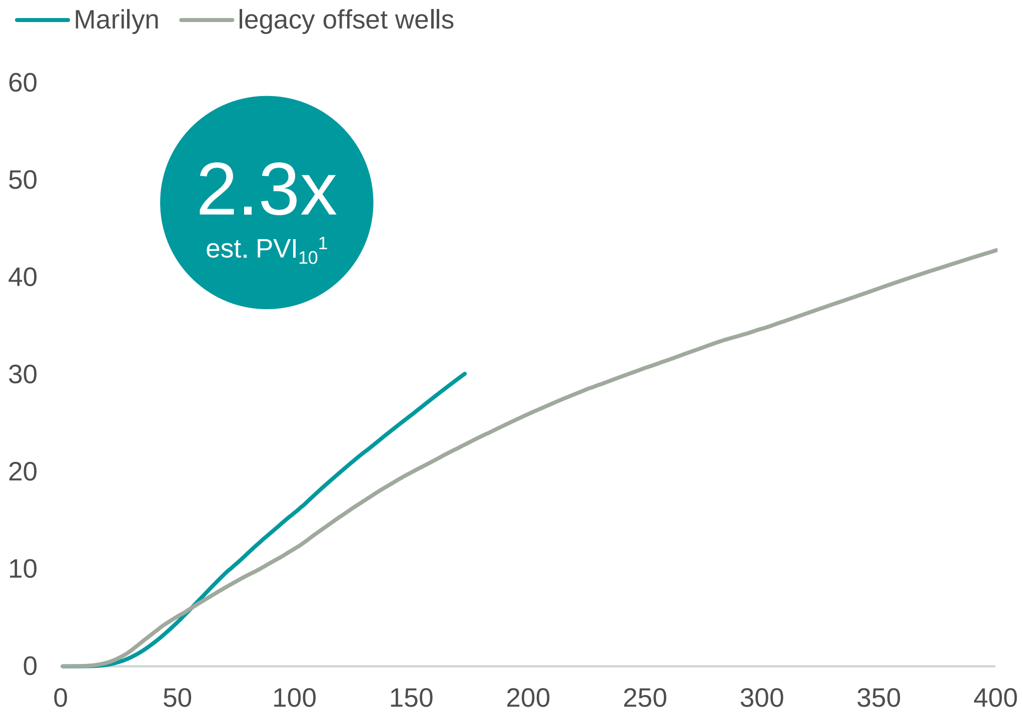
Days Online vs Cumulative boe per Lateral Foot

Lonerock (mixed gas & oil)



- Legacy wells are Coterra operated, 2018 vintage
- Carel/Elder is a 4.9 net (5 gross) well project that came online August 2021
- Gatz/Williams is a 3.9 net (4 gross) well project that came online April 2024

Downdip (gas & NGL weighted)



- Legacy wells are Coterra operated, 2016-2017 vintage
- Marilyn is a 4.4 net (5 gross) well project that came online May 2024

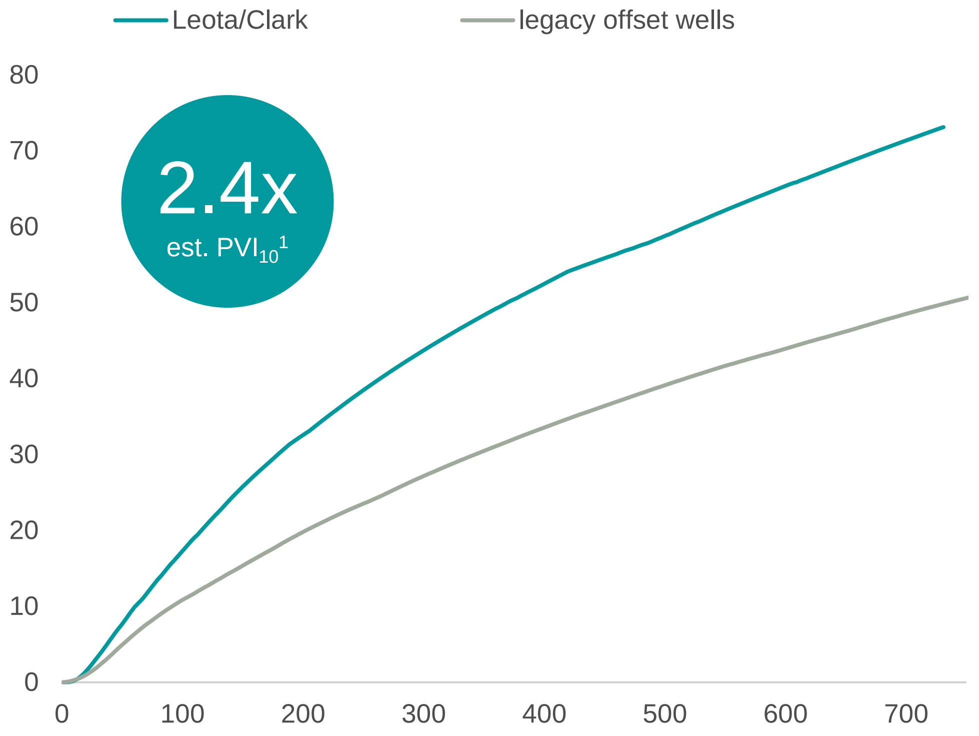
See appendix for non-GAAP reconciliations and definitions, and other defined terms. 1) Estimated PVI10 assumes flat prices of $3.50/mmbtu and $75/bbl (40% for NGL price), and well costs of $1,250/ft.

Recent Anadarko Projects are Outperforming Legacy Offsets

Wider spacing driving improved productivity & higher returns

Days Online vs Cumulative boe per Lateral Foot

Updip (oil weighted)



- Legacy wells are non-op, 2017 vintage
- Leota/Clark is a 5.8 net (6 gross) well project that came online late October 2022

Operational improvements made over time

	2014-2018 vintage	Current estimates
Wells per section	8-12	4-8 for Updip & Downdip 3-4 for Lonerock
Average lateral length	5,500’	9,760’ Cored up position with acreage trades in recent years, allowing for longer laterals
Est. well cost	$1,450/ft	$1,250/ft

See appendix for non-GAAP reconciliations and definitions, and other defined terms. 1) Estimated PVI10 assumes flat prices of $3.50/mmbtu and $75/bbl (40% for NGL price), and well costs of $1,250/ft.

Executive Compensation Tied to Emissions Reduction Metrics

20% of total short-term incentive potential

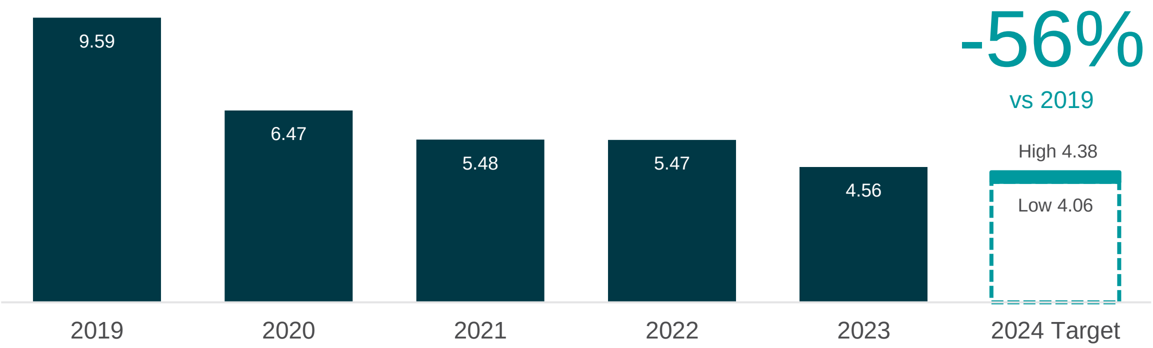
Climate Targets

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
GHG Intensity (MT CO_2e/Gross Mboe Produced)	4.22
Methane Intensity (MT CH_4, Emitted / Gross MT CH_4, Produced)	0.016%
Flared Intensity (Volume of Gas Flared / Volume of Gas Produced)	0.077%
Flyover Finding Goal (Findings / Flight)	11.55

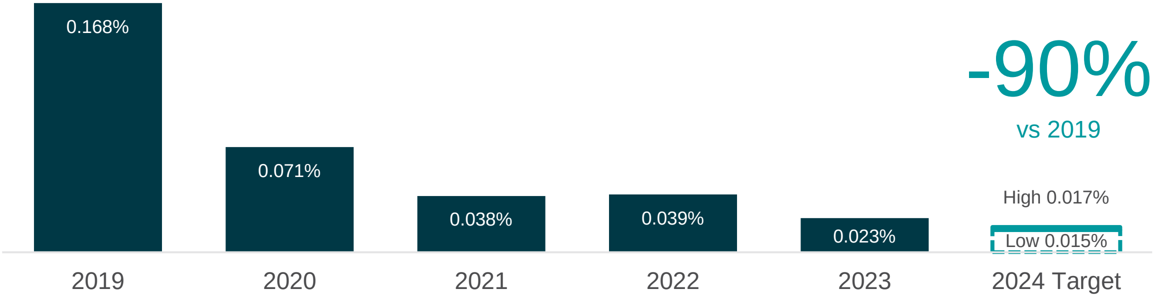
Greenhouse Gas Emissions Intensity

MT CO_2e / Gross Mboe Produced



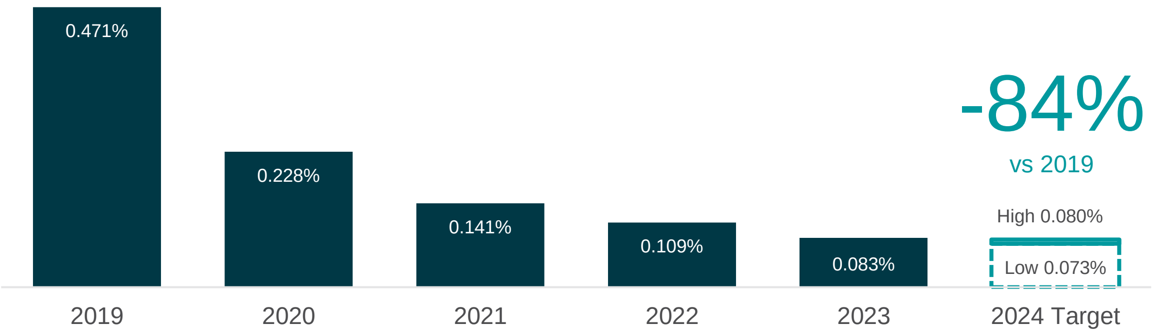
Methane Emissions Intensity

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.

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

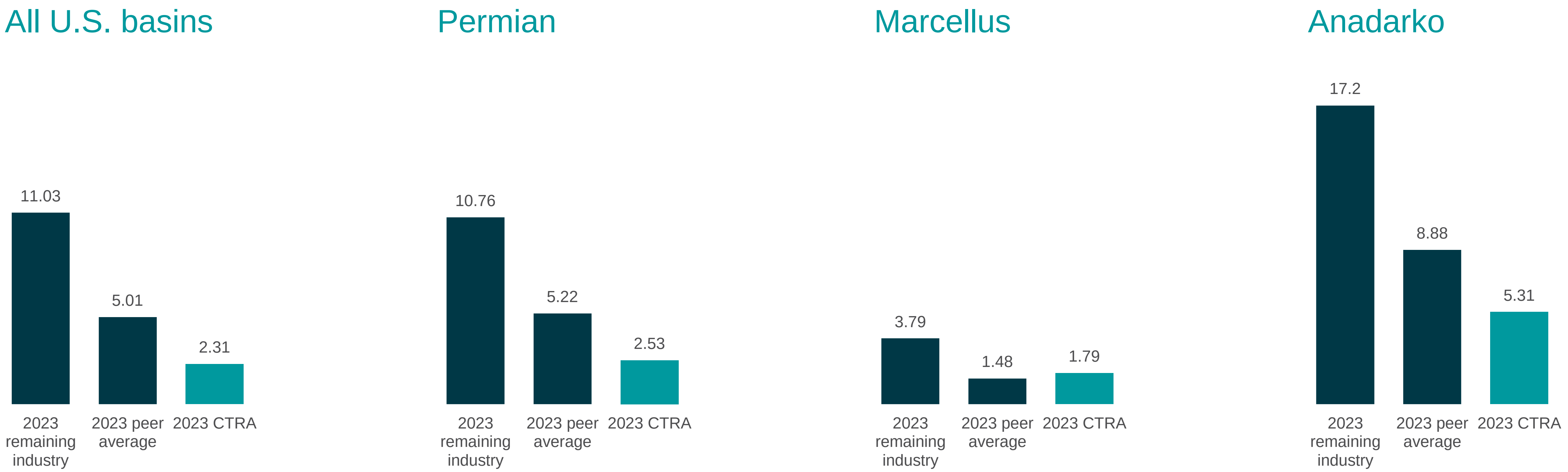
Fugitive Emissions

- 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:

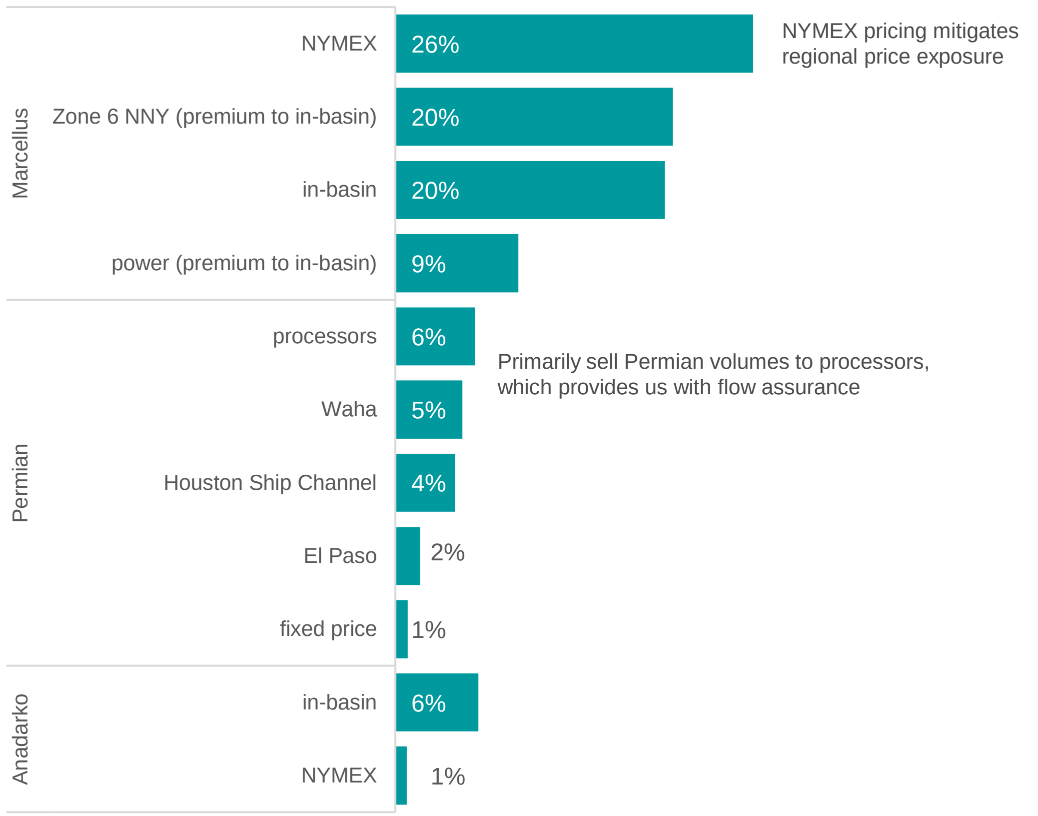


1) Compensation peer group is comprised of AR, APA, DVN, EXE, FANG, EOG, EQT, HES, MRO, OXY, OVV, and PXD.

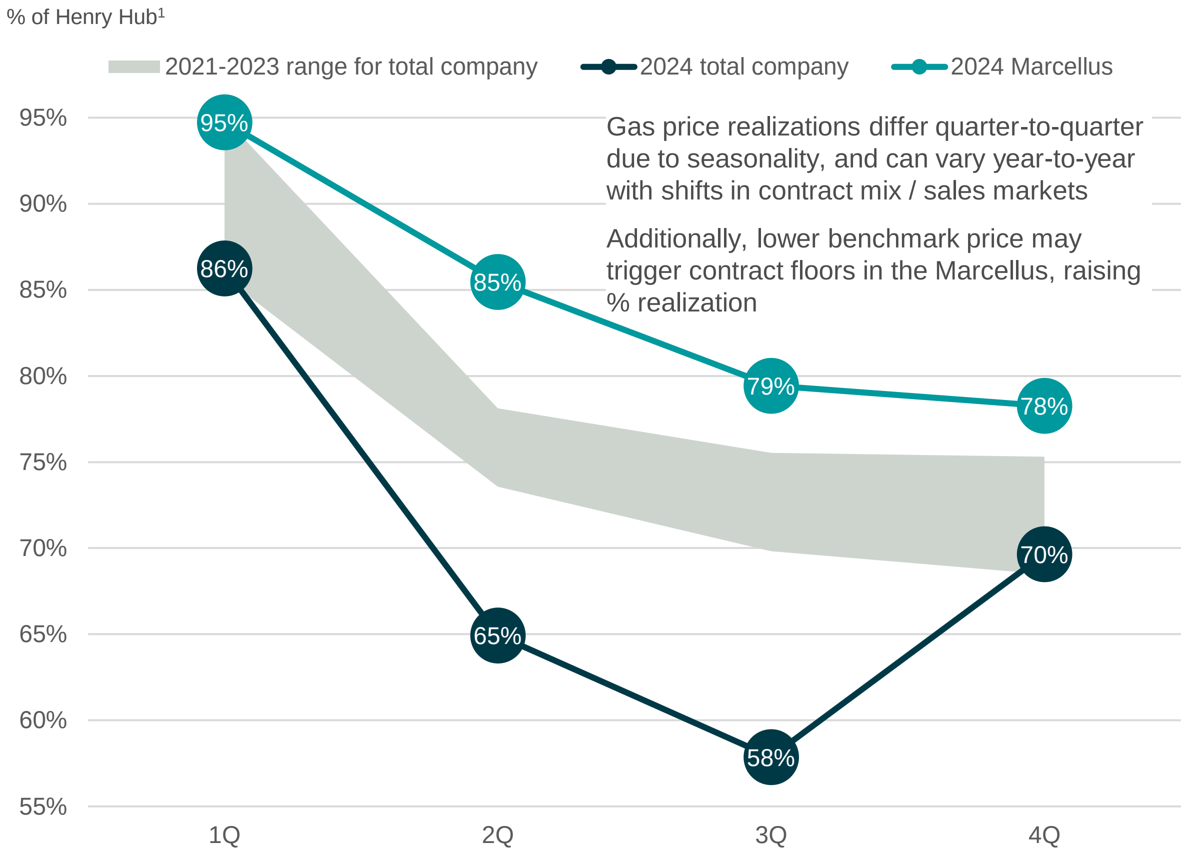
Appendix

Diversified Gas Marketing Portfolio

2024 Estimated Natural Gas Sales Markets



2021-2023 Natural Gas Price Realization Range[1]

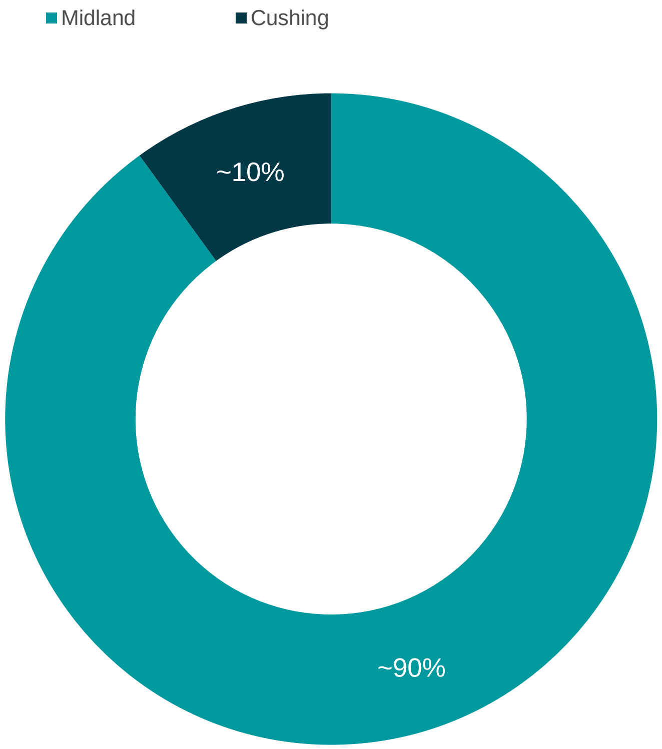


COTERRA

Note: Marcellus primarily first-of-month pricing while Anadarko & Permian are primarily Gas Daily Average pricing.1) Pre-hedge price realizations depicted. MMBtu converted at 1.03 multiplier for Mcf value. See guidance tables for benchmark price assumptions.

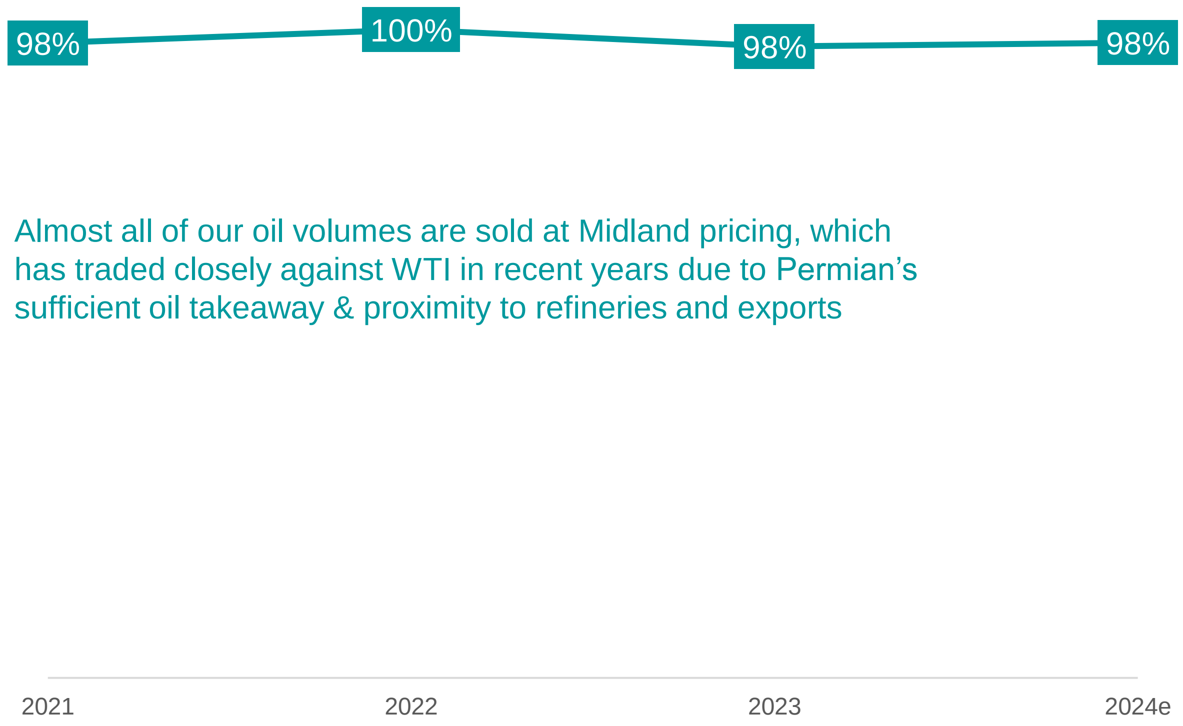
Oil Sales Primarily at Midland

2024 Estimated Oil Sales Markets



Strong Oil Price Realizations

% of WTI[1]



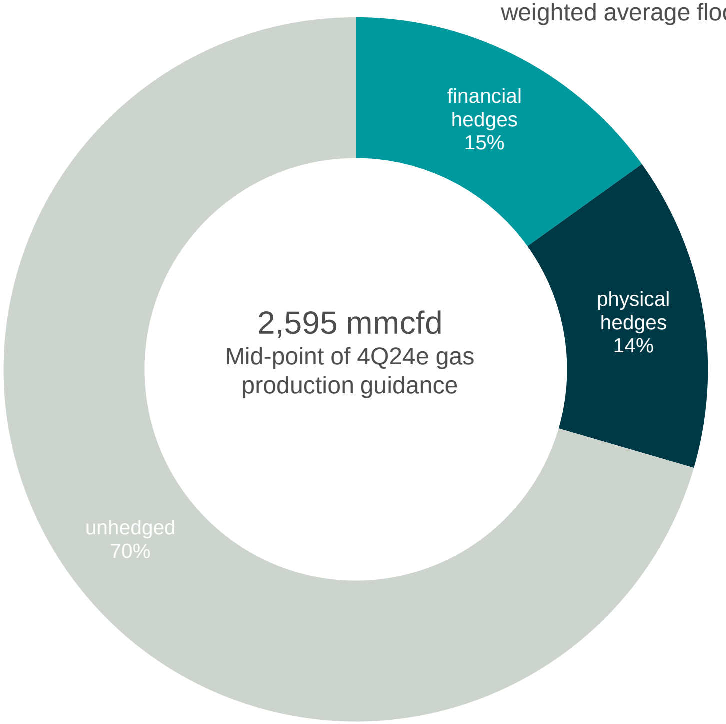
Almost all of our oil volumes are sold at Midland pricing, which has traded closely against WTI in recent years due to Permian's sufficient oil takeaway & proximity to refineries and exports

1) Pre-hedge price realizations depicted. 2024e based on recent price trends; see appendix for commodity price assumptions.

Remaining 2024 Hedge Position

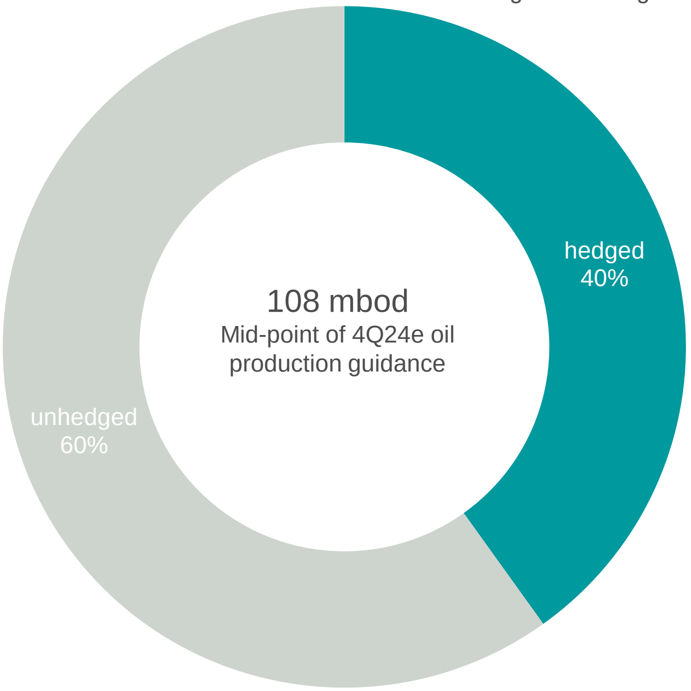
Remaining 2024e gas volumes ~30% hedged

$2.75/MMBtu & $4.46/MMBtu
weighted average floor & ceiling price



Remaining 2024e oil volumes ~40% hedged

~$65/bbl & ~$87/bbl
weighted average floor & ceiling price



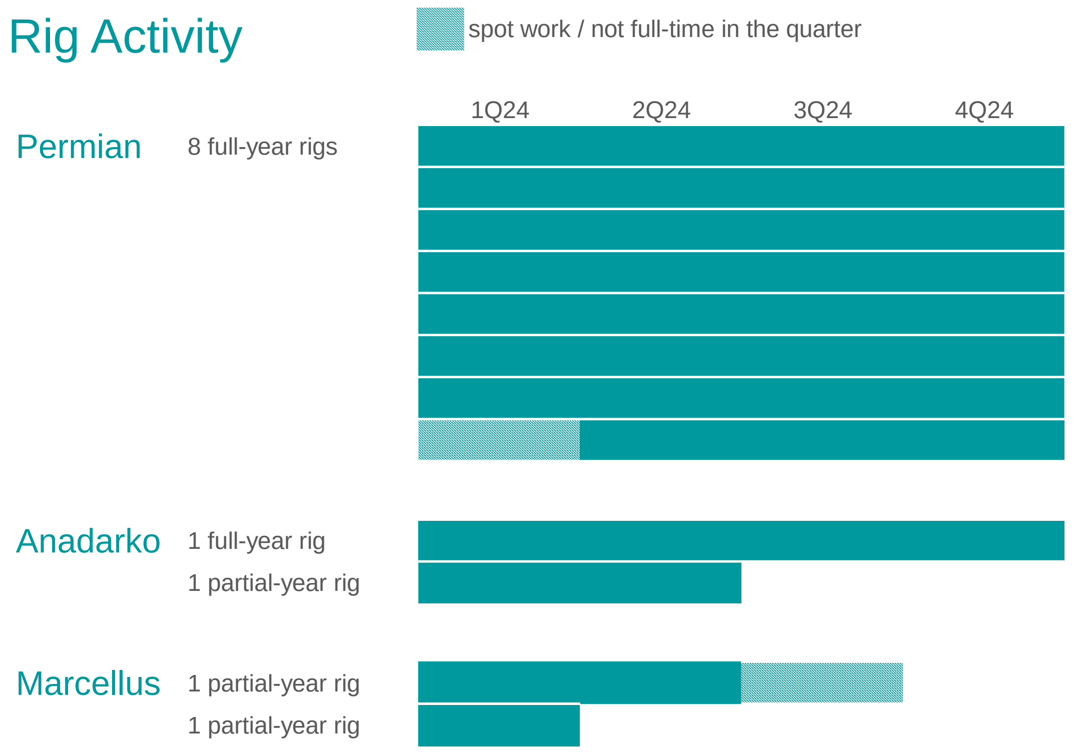
Guidance & Actuals

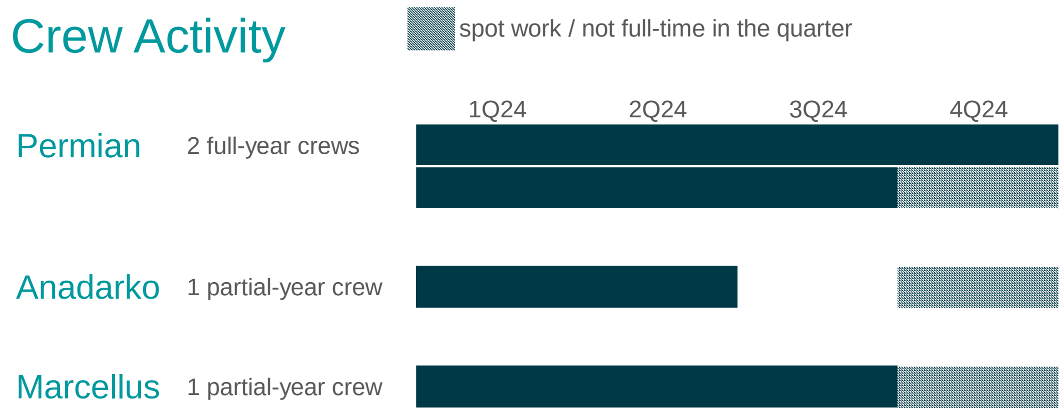
		2023 Guidance	2023 Actual	2024 Guidance (August)			Updated 2024 Guidance			3Q24 Guidance			3Q24 Actual	4Q24 Guidance		
				Low	Mid	High	Low	Mid	High	Low	Mid	High		Low	Mid	High
Operations	Total Production (mboed)	655 - 665	667	645	660	675	660	668	675	620	635	650	669	630	645	660
	Gas (mmcfd)	2,840 - 2,870	2,884	2,675	2,725	2,775	2,735	2,755	2,775	2,500	2,565	2,630	2,682	2,530	2,595	2,660
	Oil (mbod)	94.5 - 95.5	96.2	105.5	107.0	108.5	107.0	107.5	108.0	107.0	109.0	111.0	112.3	106.0	108.0	110.0
	Net wells online															
	Marcellus	65 - 75	71	37	40	43		40		0	4	7	7		11	
	Permian	85 - 95	95	80	85	90		No change		15	20	25	24	13	18	23
	Anadarko	7 - 7	7	21	24	27		No change		5	5	5	5	1	4	7
	$ millions:															
	Incurred Capital Expenditures	$2,000 - $2,200	$2,104	$1,750	$1,850	$1,950	$1,750	$1,800	$1,850	$450	$480	$530	$418	$410	$455	$500
	Marcellus D&C	$790 - $880	$834		$375 midpoint			$300 midpoint					$77			
	Permian D&C	$880 - $980	$932		$1,000 midpoint			$1,050 midpoint					$265			
	Anadarko D&C	$160 - $170	$151		$290 midpoint			$300 midpoint					$50			
	Midstream, saltwater disposal, infrastructure	$170 - $170	$187		$185 midpoint			$150 midpoint					$25			
Cash Flow & Investment	Commodity price assumptions:															
	WTI ($ per bbl)	$79	$78		$80			$76								
	Henry Hub ($ per mmbtu)	$2.77	$2.72		$2.37			$2.22								
	$ billions:															
	Discretionary Cash Flow	$3.5	$3.4		$3.2			$2.9								
	Incurred Capital Expenditures	$2.0 - $2.2	$2.1	$1.75	$1.85	$1.95	$1.75	$1.80	$1.85							
	GAAP Cash paid for capital expenditures for drilling, completion, and other fixed asset additions		$2.1													
	Free Cash Flow (DCF - cash capex)	$1.3	$1.3		$1.3			$1.1								

Note: See appendix for non-GAAP reconciliations and definitions.

Expected 2024 Operational Cadence

Subject to change





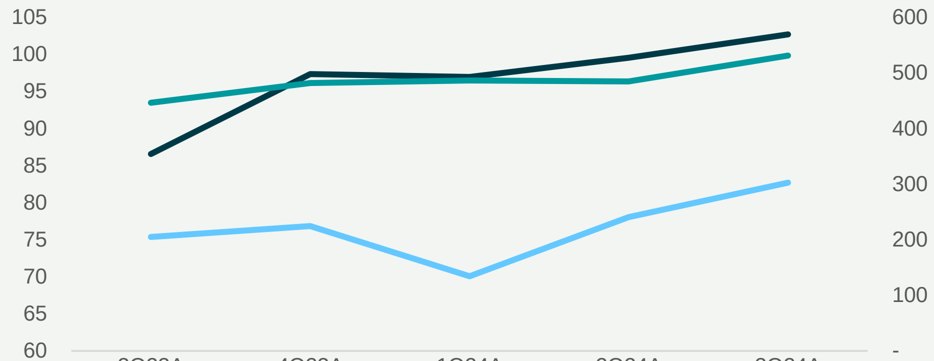
QoQ changes to activity levels

- Dropped Marcellus rig mid-August; we had originally planned to maintain that rig at least through year-end
- Originally planned for Anadarko spot crew in 4Q but were able to drop that crew & instead leverage Permian frac crew in the Anadarko for 2 weeks in October

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

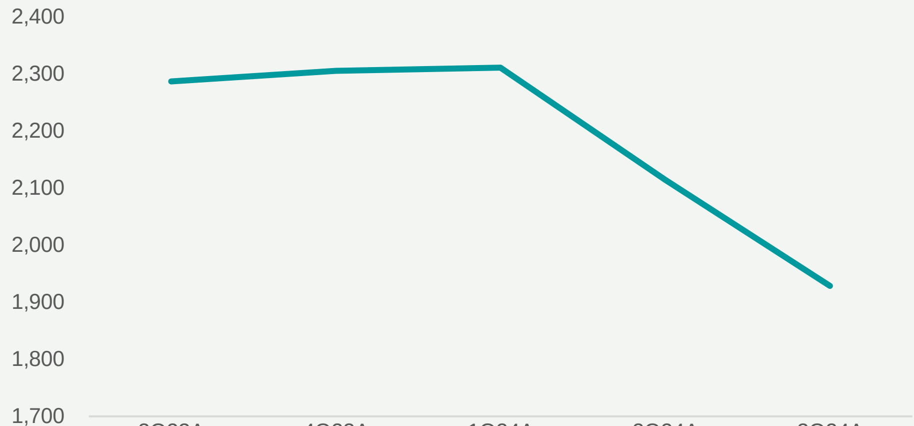
Production Profile

Permian



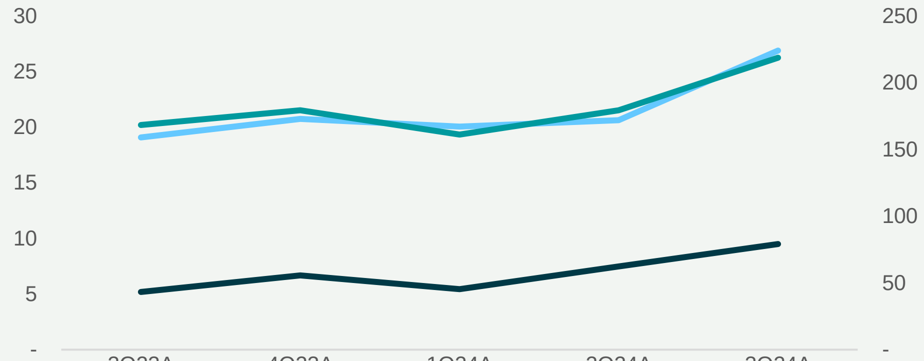
	3Q23A	4Q23A	1Q24A	2Q24A	3Q24A
Oil mbbld	87	97	97	100	103
NGL mboed	75	77	70	78	83
Gas mmcfd (right axis)	446	482	487	484	531

Marcellus



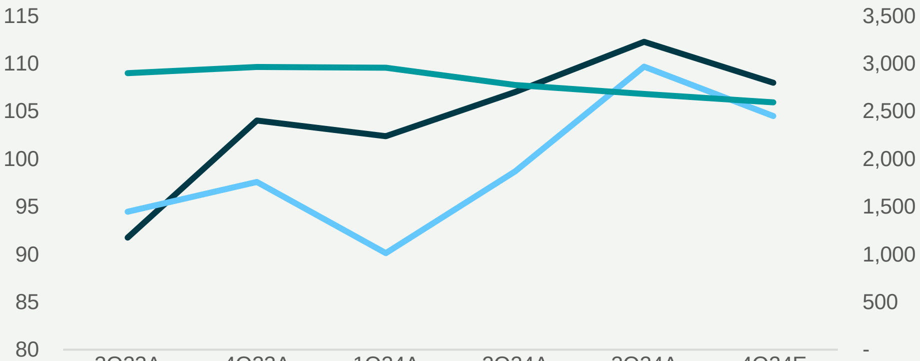
	3Q23A	4Q23A	1Q24A	2Q24A	3Q24A
Gas mmcfd	2,286	2,305	2,311	2,114	1,929

Anadarko



	3Q23A	4Q23A	1Q24A	2Q24A	3Q24A
Oil mbbld	5	7	5	7	10
NGL mboed	19	21	20	21	27
Gas mmcfd (right axis)	168	179	161	179	219

Coterra



	3Q23A	4Q23A	1Q24A	2Q24A	3Q24A	4Q24E
Oil mbbld	92	104	102	107	112	108
NGL mboed	94	98	90	99	110	105
Gas mmcfd (right axis)	2,901	2,966	2,959	2,778	2,682	2,595

Note: 4Q24e based on mid-point guidance.

Expense Guidance & Actuals

Expense	2023 Actual	2024 Guidance					1Q24 Actual	2Q24 Actual	3Q24 Actual
$ per boe, unless noted:									
Lease operating expense + workovers + region office	$2.31	$2.15	-	$2.50	-	$2.85	$2.50	$2.62	$2.69
Gathering, processing, & transportation	$4.00	$3.50		$4.00	-	$4.50	$4.00	$3.99	$3.97
Taxes other than income	$1.16	$1.00		$1.10	-	$1.20	$1.19	$0.89	$1.08
General & administrative[1]	$0.90	$0.80		$0.90	-	$1.00	$0.99	$0.85	$0.99
Unit Operating Cost	$8.37	$7.45	-	$8.50	-	$9.55	$8.68	$8.35	$8.73
DD&A	$6.74	$6.75	-	$7.25	-	$7.75	$6.92	$7.34	$7.73
Exploration[2]	$0.08	$0.05	-	$0.08	-	$0.10	$0.07	$0.09	$0.15
% effective tax rate	24%						19%	22%	21%
% cash tax rate[3]	20%			25%			24%	22%	33%

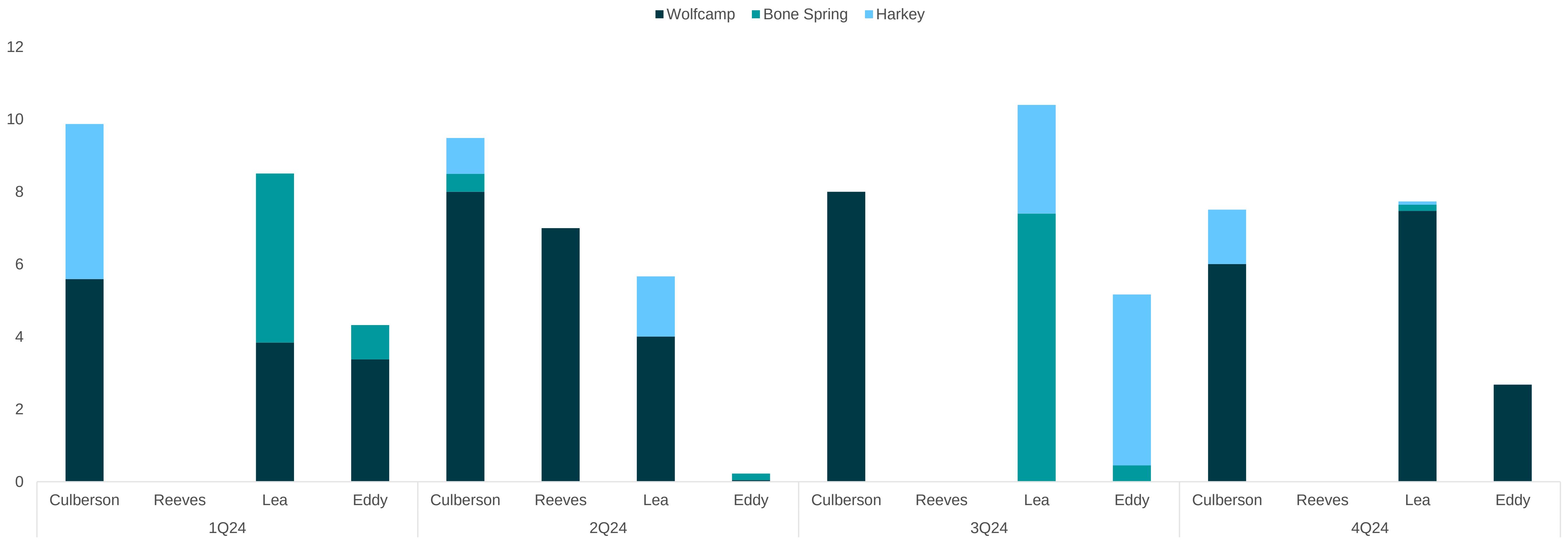
1 Excludes stock-based compensation, merger-related expenses, and severance expense

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 FY24 cash tax rate (current tax / pre-tax income) to be approximately 25%. Over time, we expect this cash tax rate estimate to decrease as the effects of the R&D amortization versus previous expensing minimizes.

Expect 2024 Permian Program to be ~50% Texas & ~50% New Mexico

2024e net wells online



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. 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 future impairments and future changes in capital. 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)	30-Sep 2024
Cash flow from operating activities	$ 755
Changes in assets and liabilities	(85)
Discretionary cash flow	**670**
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(393)
Free cash flow	**$ 277**

Twelve Months Ended: ($ in millions)	Dec 31 2022	Dec 31 2023
Cash flow from operating activities	$ 5,456	$ 3,658
Changes in assets and liabilities	186	(237)
Discretionary cash flow	**5,642**	**3,421**
Cash paid for capital expenditures for drilling, completion and other fixed asset additions	(1,700)	(2,089)
Free cash flow	**$ 3,942**	**$ 1,332**

Three Months Ended: ($ in millions)	30-Sep 2024
Cash capital expenditures for drilling, completion and other fixed asset additions	$393
Change in accrued capital costs	20
Exploratory dry-hole cost	5
Capital expenditures	**$418**

Twelve Months Ended: ($ in millions)	Dec 31 2022	Dec 31 2023
Cash capital expenditures for drilling, completion and other fixed asset additions	$1,700	$2,089
Change in accrued capital costs	27	15
Capital expenditures	**$1,727**	**$2,104**

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:	**September 30**	**December 31**					
($ in millions)	**2024**	**2023**	**2022**	**2021**	**2020**	**2019**	**2018**
	Coterra			Combined Cabot + Cimarex			
Net income	$ 1,240	$ 1,625	$ 4,065	$ 1,158	$ 201	$ 681	$ 557
Plus (less):							
Interest expense, net				62	54	55	73
Interest expense	100	73	80				
Interest income	(66)	(47)	(10)				
(Gain) loss on debt extinguishment			(28)	-	-	-	-
Other expense (benefit)			(2)	-	-	1	-
Income tax expense (benefit)	366	503	1,104	344	41	219	141
Depreciation, depletion and amortization	1,810	1,641	1,635	693	391	406	417
Exploration	25	20	29	18	15	20	114
(Gain) loss on sale of assets	(3)	(12)	1	2	0	1	16
Non-cash loss (gain) on derivative instruments	(13)	54	(299)	(210)	(26)	58	(86)
(Earnings) loss on equity method investments	-	-	-	-	0	(80)	(1)
Equity method investment distributions	-	-	-	-	-	17	-
Stock-based compensation	58	59	86	57	43	31	33
Severance expense	2	12	62	46	-	3	-
Merger-related costs	-	-	7	72	-	-	-
EBITDAX	**$ 3,519**	**$ 3,928**	**$ 6,730**	**$ 2,242**	**$ 719**	**$ 1,412**	**$ 1,264**
Legacy Cimarex EBITDAX				1,005	935	1,460	1,558
Combined EBITDAX	**$ 3,519**	**$ 3,928**	**$ 6,730**	**$ 3,247**	**$ 1,654**	**$ 2,872**	**$ 2,822**

	September 30	**December 31**					
($ in millions)	**2024**	**2023**	**2022**	**2021**	**2020**	**2019**	**2018**
	Coterra			Combined Cabot + Cimarex			
Total debt	$2,066	$2,161	$2,181	$3,125	$3,134	$3,220	$2,726
Less: Cash and cash equivalents	(843)	(956)	(673)	(1,036)	(413)	(295)	(803)
Less: Short-term investments							
Net debt	$1,223	$1,205	$1,508	$2,089	$2,721	$2,925	$1,923
TTM EBITDAX	$3,519	$3,928	$6,730	$3,247	$1,654	$2,872	$2,822
Net debt to TTM EBITDAX	**0.3x**	**0.3x**	**0.2x**	**0.6x**	**1.6x**	**1.0x**	**0.7x**