JULY 2023

INVESTOR PRESENTATION

CALLON

PETROLEUM

Important Disclosures

Cautionary Statement Regarding Forward-Looking Information

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements include all statements regarding the company's expectations and plans with respect to the Delaware Basin acquisition and Eagle Ford disposition, including the timing thereof; the Company's expectations and plans with respect to a share repurchase program; wells anticipated to be drilled and placed on production; inventory and delineation; future levels of development activity and associated production, capital expenditures, cash flow expectations and expected uses thereof, and margins; expectations and estimates relating to income statement expenditures and capital expenditures; estimated realizations; estimated reserve quantities and the present value thereof; future income and returns; future debt levels and leverage and the implementation of the Company's business plans and strategy, as well as statements including the words "believe," "expect," "plans," "may," "will," "should," "could," and words of similar meaning. These statements reflect the Company's current views with respect to future events and financial performance based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. No assurances can be given, however, that these events will occur or that these projections will be achieved, and actual results could differ materially from those projected as a result of certain factors. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. Some of the factors which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements include the volatility of oil and natural gas prices; changes in the supply of and demand for oil and natural gas, including as a result of actions by, or disputes among members of OPEC and other oil and natural gas producing countries with respect to production levels or other matters related to the price of oil; general economic conditions or as a result of our ability to drill and complete wells; operational, regulatory and environment risks; the cost and availability of equipment and labor; our ability to finance our development activities at expected costs or at expected times or at all; rising interest rates and inflation; our inability to realize the benefits of recent transactions; currently unknown risks and liabilities relating to the newly acquired assets and operations; adverse actions by third parties involved with the transactions; risks that are not yet known or material to us; and other risks more fully discussed in our filings with the SEC, including our most recent Annual Report on Form 10-K and subsequent Quarterly Reports on Form 10-Q, available on our website or the SEC's website at www.sec.gov. Any forward-looking statement speaks only as of the date on which such statement is made, and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Non-GAAP Financial Measures

This presentation refers to non-GAAP financial measures such as "adjusted income," "adjusted income per diluted share," "adjusted free cash flow," "adjusted EBITDAX," "adjusted EBITDAX per Boe," "PV-10," and "net debt". These measures, detailed below, are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes), included in our filings with the U.S. Securities and Exchange Commission (the "SEC") and posted on our website.

PV-10 is a supplemental non-GAAP measure. We believe that the presentation of PV-10 provides greater comparability when evaluating oil and gas companies due to the many factors unique to each individual company that impact the amount and timing of future income taxes. In addition, we believe that PV-10 is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and gas companies. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

Adjusted free cash flow is a supplemental non-GAAP measure that is defined by the Company as net cash provided by operating activities before net change in working capital, changes in accrued hedge settlements, merger, integration and transaction expense, and other income and expense less capital expenditures before increase (decrease) in accrued capital expenditures. We believe adjusted free cash flow provides useful information to investors because it is a comparable metric against other companies in the industry and is a widely accepted financial indicator of an oil and natural gas company's ability to generate cash for the use of internally funding their capital development program and to service or incur debt. Adjusted free cash flow is not a measure of a company's financial performance under GAAP and should not be considered as an alternative to net cash provided by operating activities, or as a measure of liquidity.

Callon calculates adjusted EBITDAX as net income (loss) before interest expense, income tax expense (benefit), depreciation, depletion and amortization, (gains) losses on derivative instruments excluding net settled derivative instruments, impairment of oil and gas properties, non-cash share-based compensation expense, exploration expense, merger, integration and transaction expense, (gain) loss on extinguishment of debt, and certain other expenses. Adjusted EBITDAX is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities or other income or cash flow data prepared in accordance with GAAP. However, the Company believes that adjusted EBITDAX provides useful information to investors because it provides additional information with respect to our performance or ability to meet our future debt service, capital expenditures and working capital requirements. Because adjusted EBITDAX excludes some, but not all, items that affect net income (loss) and may vary among companies, the adjusted EBITDAX presented above may not be comparable to similarly titled measures of other companies.

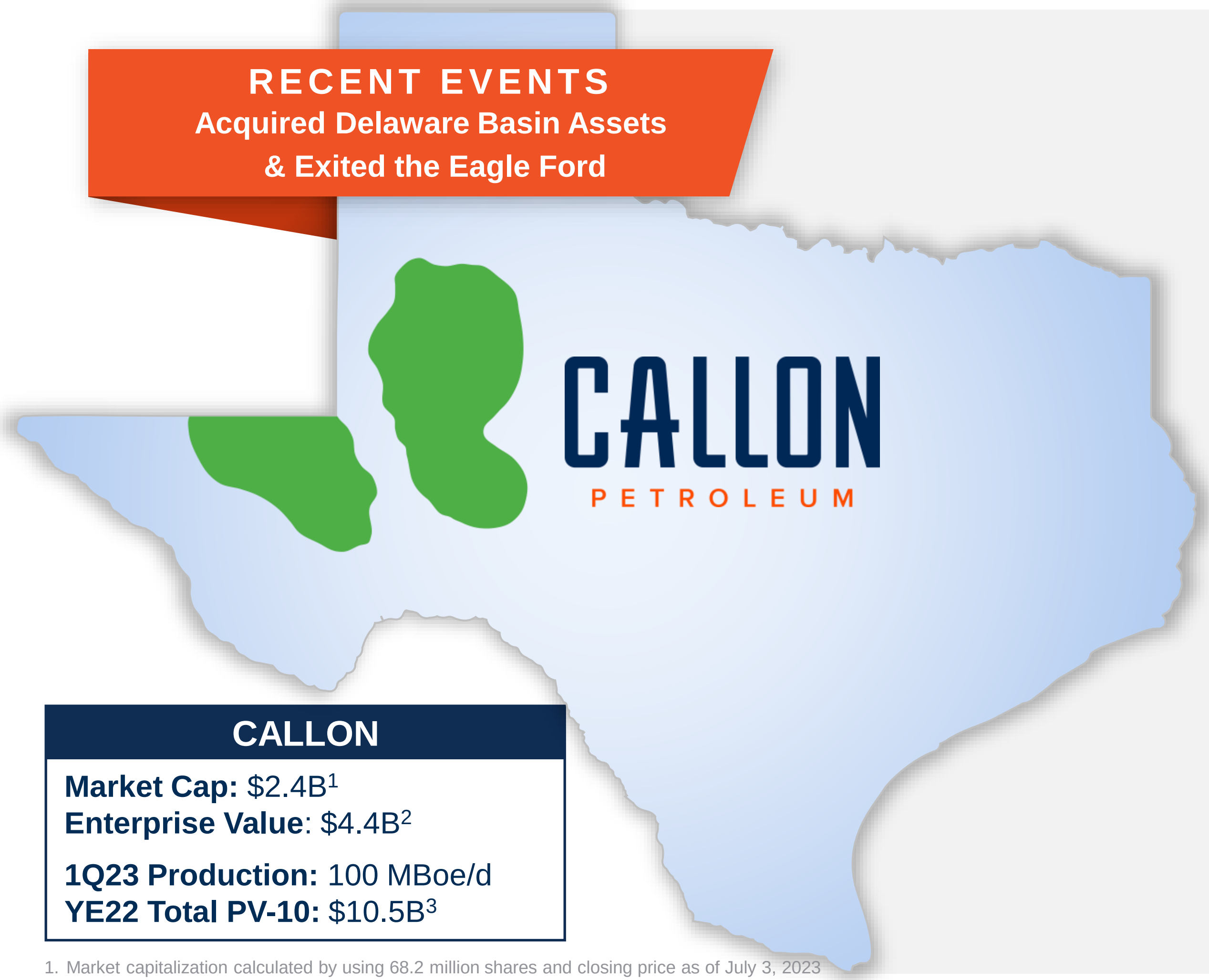
Adjusted income and adjusted income per diluted share are supplemental non-GAAP measures that Callon believes are useful to investors because they provide readers with a meaningful measure of our profitability before recording certain items whose timing or amount cannot be reasonably determined. These measures exclude the net of tax effects of these items and non-cash valuation adjustments, which are detailed in the reconciliation provided. Adjusted income and adjusted income per diluted share are not measures of financial performance under GAAP. Accordingly, neither should be considered as a substitute for net income (loss), operating income (loss), or other income data prepared in accordance with GAAP. However, the Company believes that adjusted income and adjusted income per diluted share provide additional information with respect to our performance. Because adjusted income and adjusted income per diluted share exclude some, but not all, items that affect net income (loss) and may vary among companies, the adjusted income and adjusted income per diluted share presented above may not be comparable to similarly titled measures of other companies.

Net debt is a supplemental non-GAAP measure that is defined by the Company as total debt excluding unamortized premiums, discount, and deferred loan costs, less cash and cash equivalents. Net debt should not be considered an alternative to, or more meaningful than, total debt, the most directly comparable GAAP measure. Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. We believe this metric is useful to analysts and investors in determining the Company's leverage position since the Company has the ability to, and may decide to, use a portion of its cash and cash equivalents to reduce debt.

The Company is unable to reconcile the projected adjusted free cash flow (non-GAAP), net debt and adjusted EBITDAX (non-GAAP) metrics included in this release to projected net cash provided by operating activities (GAAP), total debt and net income (loss) (GAAP), respectively, without unreasonable efforts because components of the calculations are inherently unpredictable, such as changes to current assets and liabilities, the timing of capital expenditures, movements in oil and gas pricing, unknown future events, and estimating future certain GAAP measures. The inability to project certain components of the calculation would significantly affect the accuracy of the reconciliation.

Why Callon *Today?*

RECENT EVENTS
Acquired Delaware Basin Assets & Exited the Eagle Ford



CALLON

Market Cap: $2.4B[1]
Enterprise Value: $4.4B[2]

1Q23 Production: 100 MBoe/d
YE22 Total PV-10: $10.5B[3]

- **Permian-Focused Asset Base**
- **"Life of Field" Co-Development Model**
- **Decade-Plus of Permian Basin Inventory**
- **Improving Well Productivity and Capital Efficiency**
- **Launching Shareholder Return Program in 3Q23**

1. Market capitalization calculated by using 68.2 million shares and closing price as of July 3, 2023
2. Reflects estimated impact of recently closed transactions
3. Includes YE'22 PV-10 value of divested Eagle Ford assets

Transactions Strengthen Our Company, Deepen Our Portfolio

SOLIDIFIES PERMIAN FOCUS

- Acquired 18,000 contiguous net acres in the Delaware Basin (>90% operated)
- **Deepens inventory** of high-return, long-lateral locations

HIGHER OPERATING MARGINS

- Maintains corporate oil-weighting
- **Reduces per-unit operating costs**

ACCRETIVE TO KEY FINANCIAL AND OPERATING METRICS

- Improves **FCF, FCF per share and capital efficiency metrics**
- Acquisition attractively valued @ 2.5x NTM EBITDA[1] (Eagle Ford sale @ 3.0x[1])

ATTAINS INITIAL DEBT MILESTONE

- Reduced total debt to **<$2.0B** at closing; next milestone **~$1.5B optimal L/T debt**
- Credit facility availability increased to over $1.3 billion

ACCELERATES SHAREHOLDER RETURN PROGRAM

- Launching **share buyback** at closing of transactions in July 2023
- **$300MM** authorization through 2Q25

1. Based on strip pricing and the next twelve-month projections as of April 28, 2023. Metrics do not include contingent payments

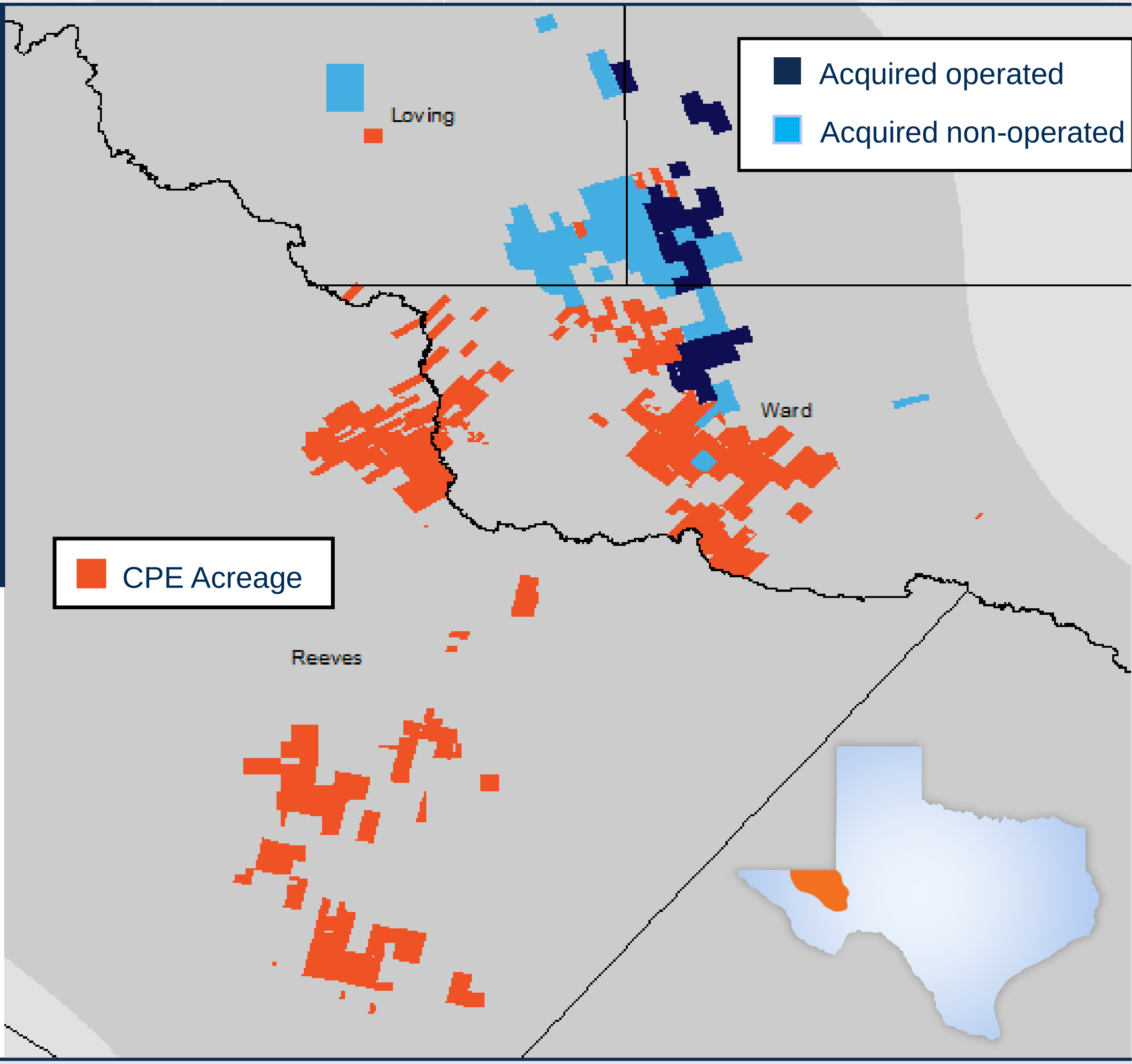
A Leading Permian Position

CONTIGUOUS TO EXISTING CORE DELAWARE POSITION

- 18k net acres in Ward, Winkler & Loving counties (92% operated)
- Includes 1.5k net non-op acres with ConocoPhillips and Continental Resources
- Operational synergies driven by regional expertise and integrated activity

QUALITY OIL INVENTORY

- ~70 high-return oil locations, avg lateral length: ~10k ft.
  - Proven 3rd Bone Spring Shale, Wolfcamp A & B benches
  - ~90% of inventory with PV10 breakeven below $45 WTI
  - Upside potential from additional stacked zones
- Positioned for proven "Life of Field" Co-Development Model



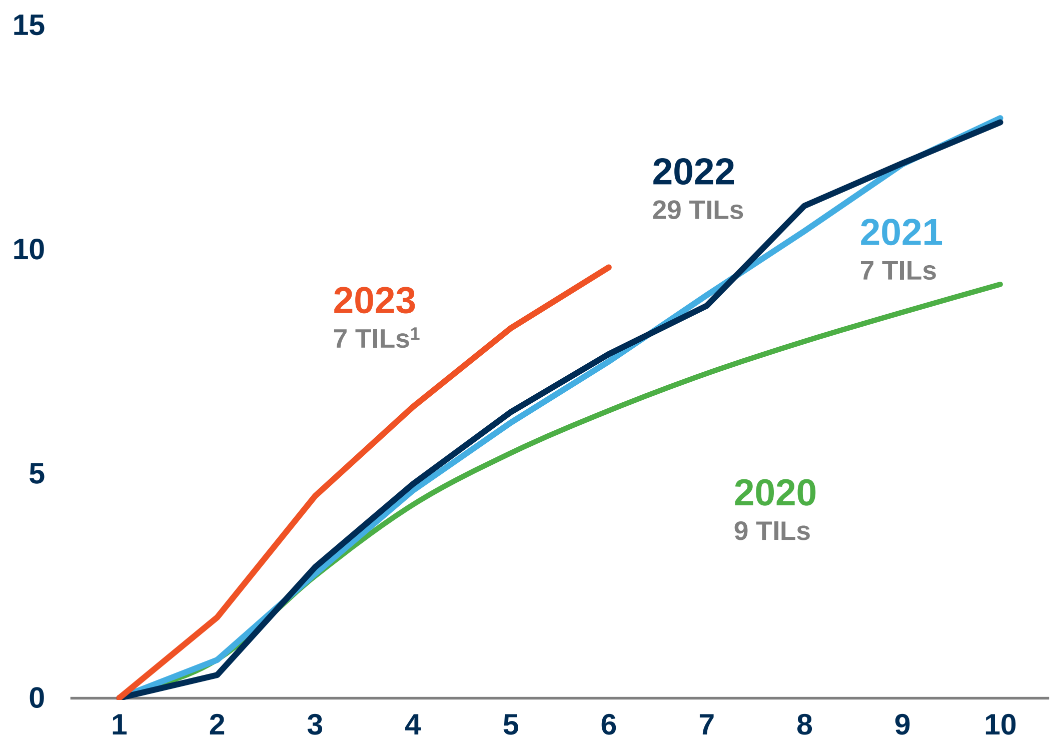
CALLON PERMIAN POSITION

	CALLON PETROLEUM	PERCUSSION PETROLEUM II LLC	Pro Forma
Net Acres	127k	18k	**145k**
Estimated Production[1] (MBoe/d)	93	14	**107**
Oil Mix (% of production)	56%	70%	**58%**
Operated Drilling Locations	1,440	70	**1,510**

1. Represents average production for the month of April 2023

Percussion Well Productivity Evolution

PERCUSSION AVERAGE CUMULATIVE PRODUCTION BY MONTH
(MBbls per 1,000 ft)



2020 – 2022

~40%

Increase in average oil recoveries

Driven by wider spacing and improved completion techniques

2023 – Forward

Further optimization of completion design

Optimal targeting & co-development strategy

1. Based on internal estimates as of June 30, 2023

Launching Shareholder Return Program

INITIATING SHARE REPURCHASE PROGRAM

$300MM BUYBACK

- Two-year program **through 2Q25**
- Represents **>12% of equity market cap[1]**

USES OF FUTURE FREE CASH FLOW

- **Deleveraging / Enhance Liquidity**
- **Shareholder Returns**
- **Reinvestment that Improves Returns**

1. As of July 3, 2023

Permian Focus Enhances Outlook

PRODUCTION & OIL MIX IN LINE WITH PREVIOUS GUIDANCE

REDUCED CAPITAL SPENDING OUTLOOK

PLAN TO REDUCE TO 5 RIGS INTO YEAR-END

- Reduction from prior plan of 6 – 7 rigs
- ~1 rig program on acquisition to be integrated into broader Permian schedule

CASH OPERATING COSTS REDUCED IN 2023 WITH STRONG TRAJECTORY INTO 2024

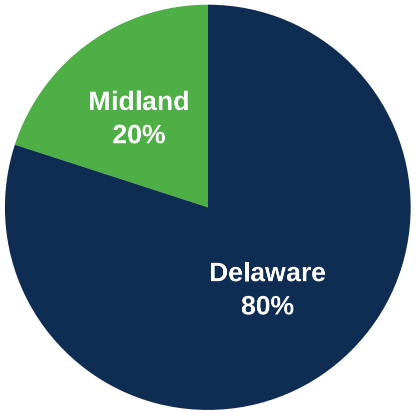
- LOE reductions from lower relative cost structure
- Approximately $15MM in identified operational cost savings

2023 GUIDANCE

	Status Quo 2023	Pro Forma 2023
Total (MBoe/d)	**104 – 107**	**103 – 106**
Oil (MBbls/d)	63 – 65	62 – 64
Lease Operating Costs ($/Boe)	8.00 – 8.50	7.75 – 8.25
Capital Expenditures ($MM)	1,000	960 – 980
Operated TILs (wells)	115 – 130	100 – 115

CAPITAL ALLOCATION

PF 2023E



1Q 2023 Value Drivers

PRODUCTION

100 MBoe/d
Total

60 MBbl/d
Oil

STRONG FINANCIAL PERFORMANCE

$1.94
Adj. Income per diluted share[1]

68%
Top-tier Adj. EBITDAX margin[2]

CAPITAL SPENDING

$270MM
~8% below midpoint of quarterly guidance

OPERATIONAL PERFORMANCE

~20%
Increase in drilling feet per day in Delaware South

>15%
Increase in completion stages per day

1Q23 ADJ. FREE CASH FLOW

$7.2MM Adj. Free Cash Flow[1]

CONTINUED DEBT REDUCTION

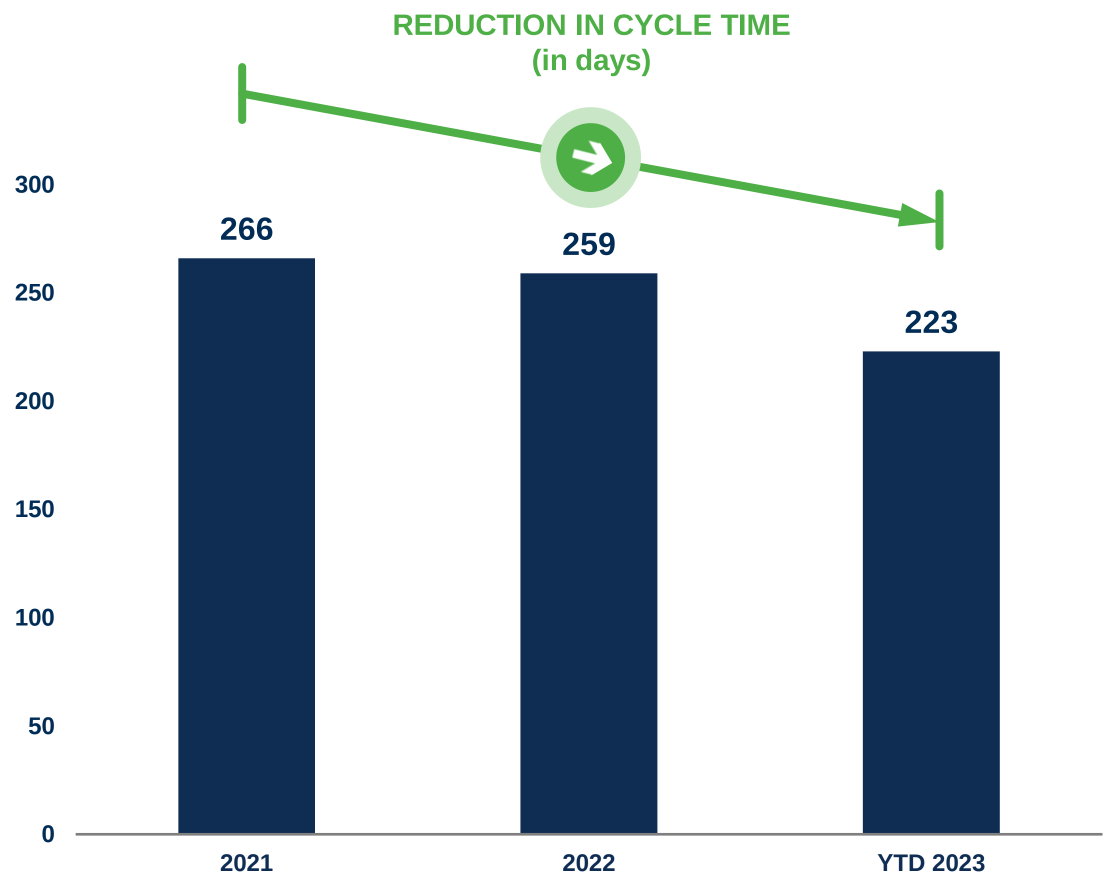
$38MM
of 1Q debt reduction

11
Consecutive quarters of debt reduction

1. Adjusted Income per diluted share and Adjusted Free Cash Flow are non-GAAP measures. Please see the appendix for a reconciliation
2. Defined as Adjusted EBITDAX divided by revenue from oil and gas sales. Adjusted EBITDAX is a non-GAAP measure., Please see the appendix for a reconciliation

Simultaneous Operations Decrease Cycle Times

DELAWARE BASIN[1]



FOURTEEN WELL DEVELOPMENT PROJECT
DELAWARE BASIN

3 Rigs

Reduction in spud to rig release >50%

Reduced time needed to complete the wells by >20 days

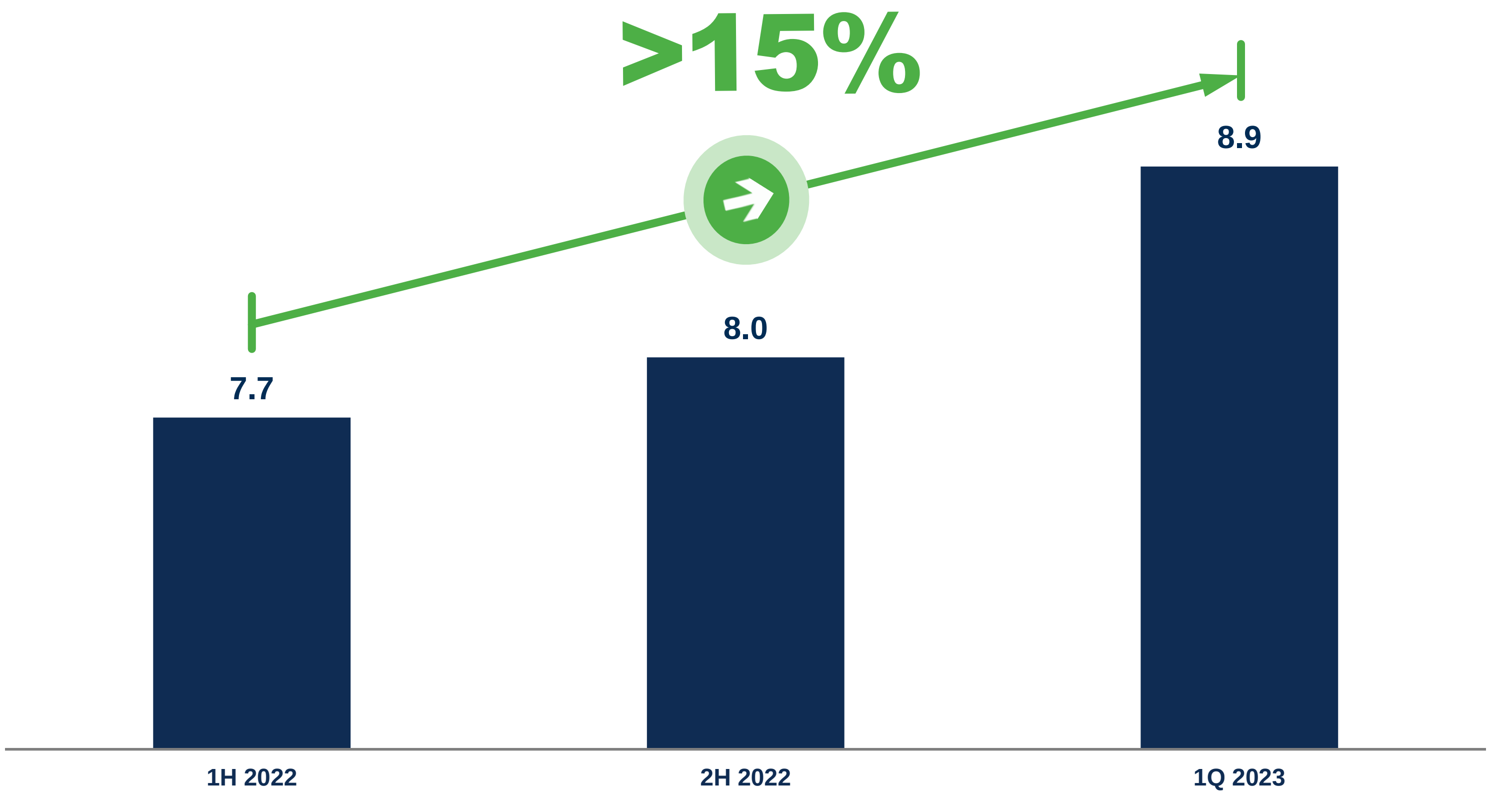
2 Completion crews

25% **Reduction in cycle times from simultaneous operations**

1. Reflects 29 Delaware Basin wells that have been turned in-line in 2023

Experience + Consistency Enhances Returns

COMPLETION STAGES PER DAY



DRILLING

- >20% increase in drilling feet per day in recent Delaware South pad
- Subsurface knowledge and improved drill bit technologies drive efficiencies

COMPLETIONS

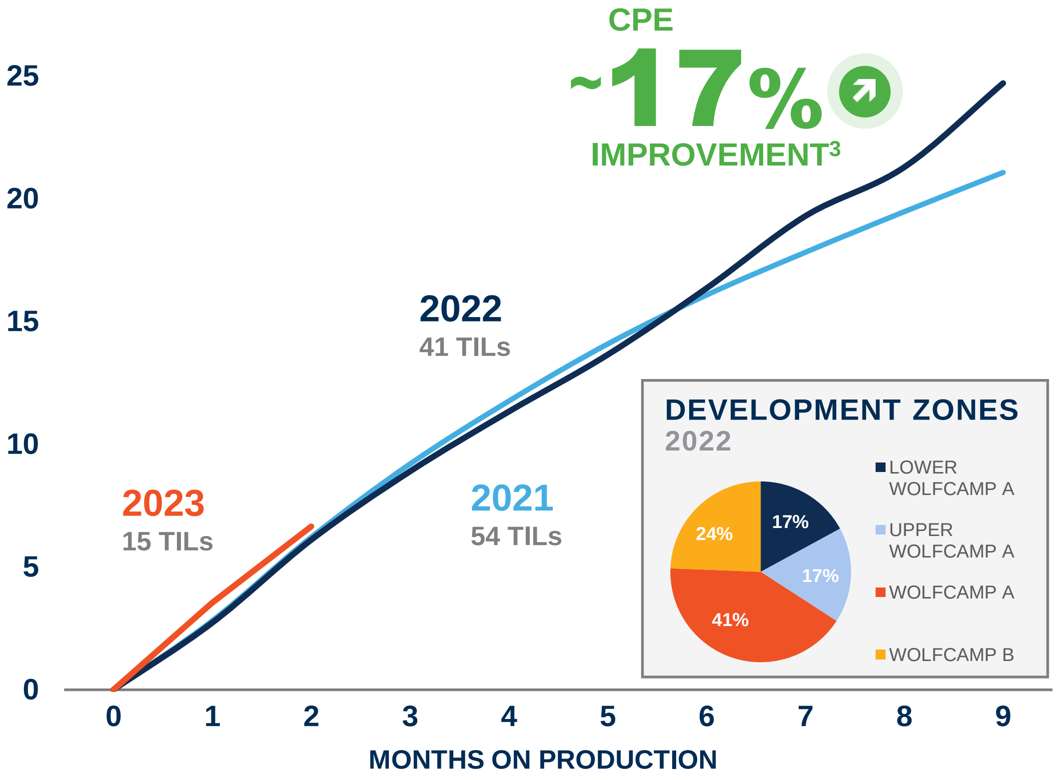
- Increased efficiencies through optimization of completion services equipment and crews
- Reduction of downtime through enhanced scheduling and coordination

"Life of Field" Co-Development Model Enhances Rate of Return

CALLON'S INCREASING WELL PRODUCTIVITY[1]

AVERAGE DELAWARE BASIN CUMULATIVE PRODUCTION BY MONTH

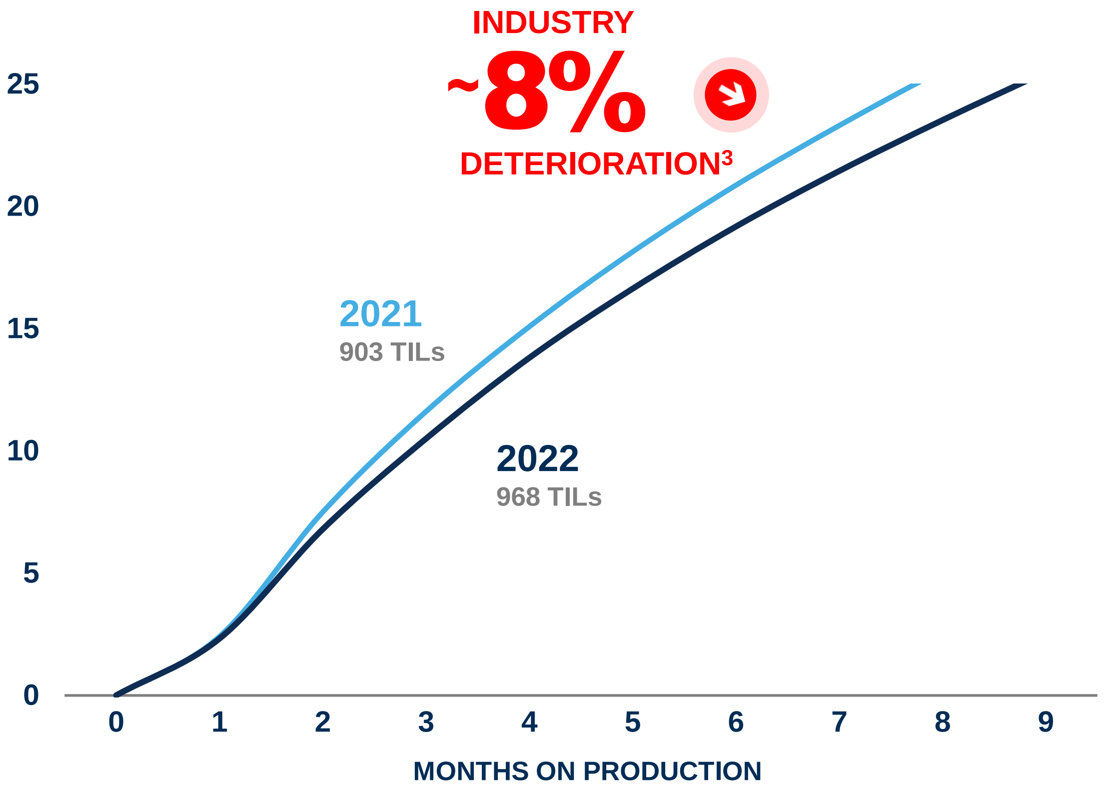
MBoe per 1,000 ft



INDUSTRY'S DEGRADING WELL PRODUCTIVITY[2]

AVERAGE DELAWARE BASIN CUMULATIVE PRODUCTION BY MONTH

MBoe per 1,000 ft



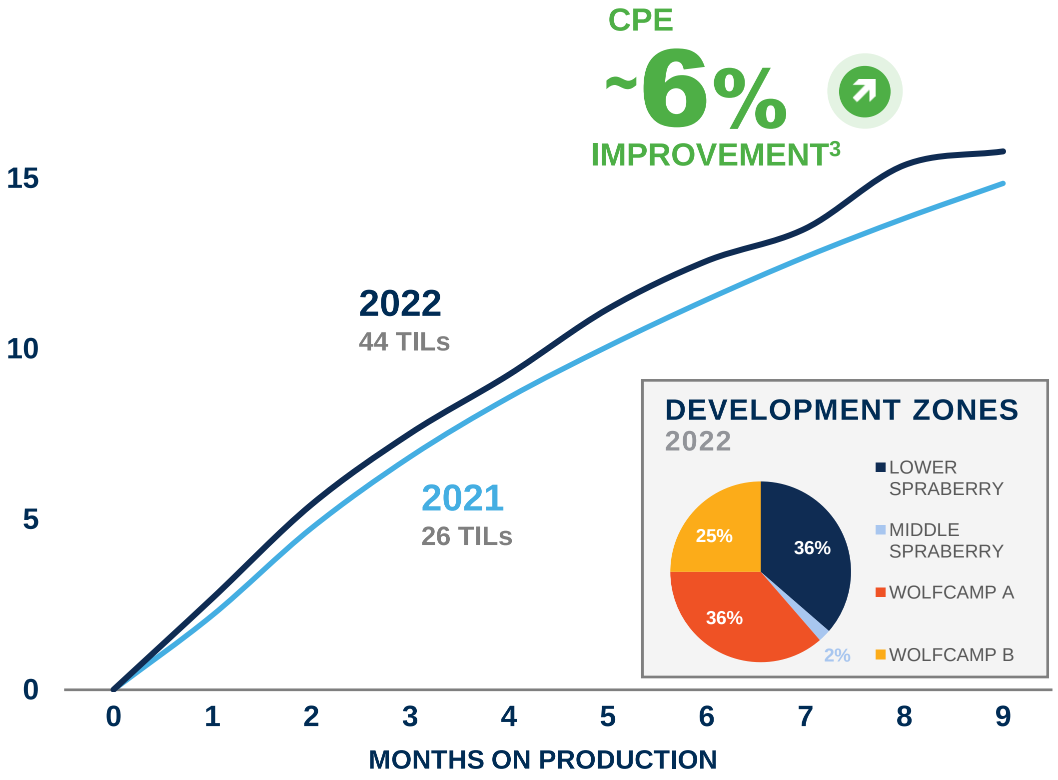
1. Based off internal estimates as of April 28, 2023
2. Includes Texas wells in the Delaware Basin. Based on data from Enverus as of April 28, 2023
3. Year over year comparison from 2021 to 2022

“Life of Field” Co-Development Model Enhances Rate of Return

CALLON’S INCREASING WELL PRODUCTIVITY[1]

AVERAGE MIDLAND BASIN CUMULATIVE PRODUCTION BY MONTH

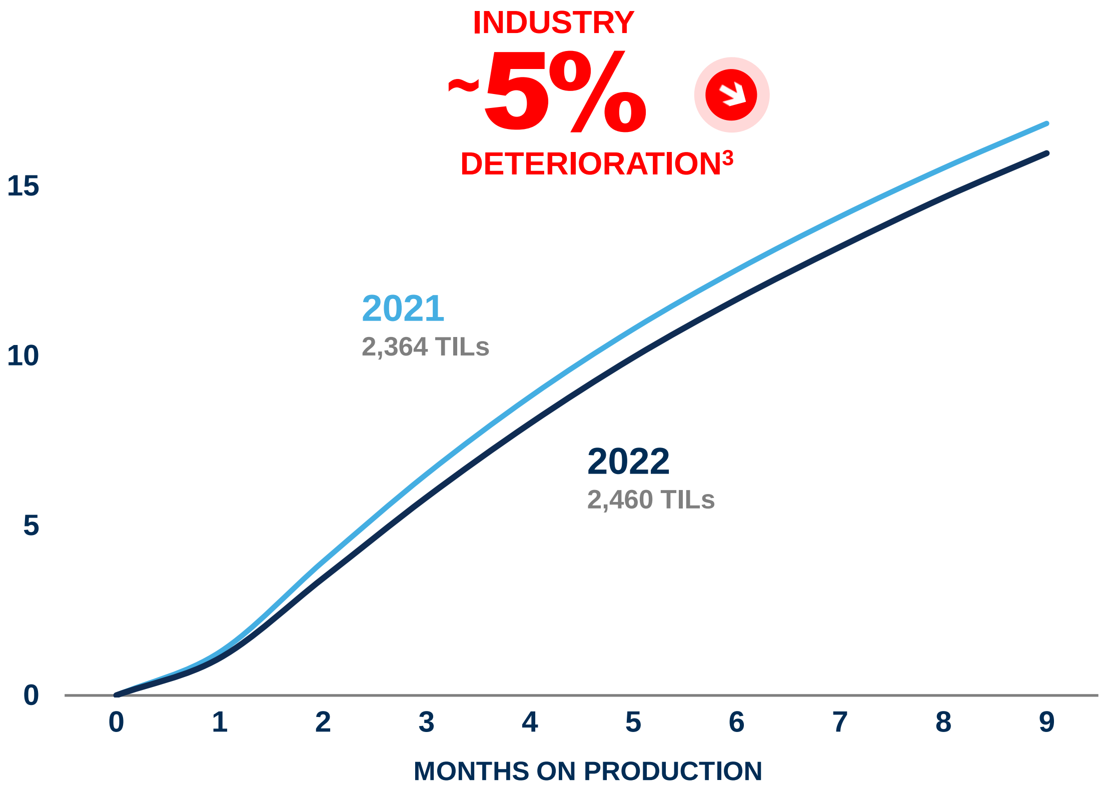
MBoe per 1,000 ft



INDUSTRY’S DEGRADING WELL PRODUCTIVITY[2]

AVERAGE MIDLAND BASIN CUMULATIVE PRODUCTION BY MONTH

MBoe per 1,000 ft



1. Based off internal estimates as of April 28, 2023
2. Based on data from Enverus as of April 28, 2023
3. Year over year comparison from 2021 to 2022

Deep Inventory of High-Quality Risked Locations

DELAWARE BASIN OPERATED LOCATIONS IN CORE ZONES[1]

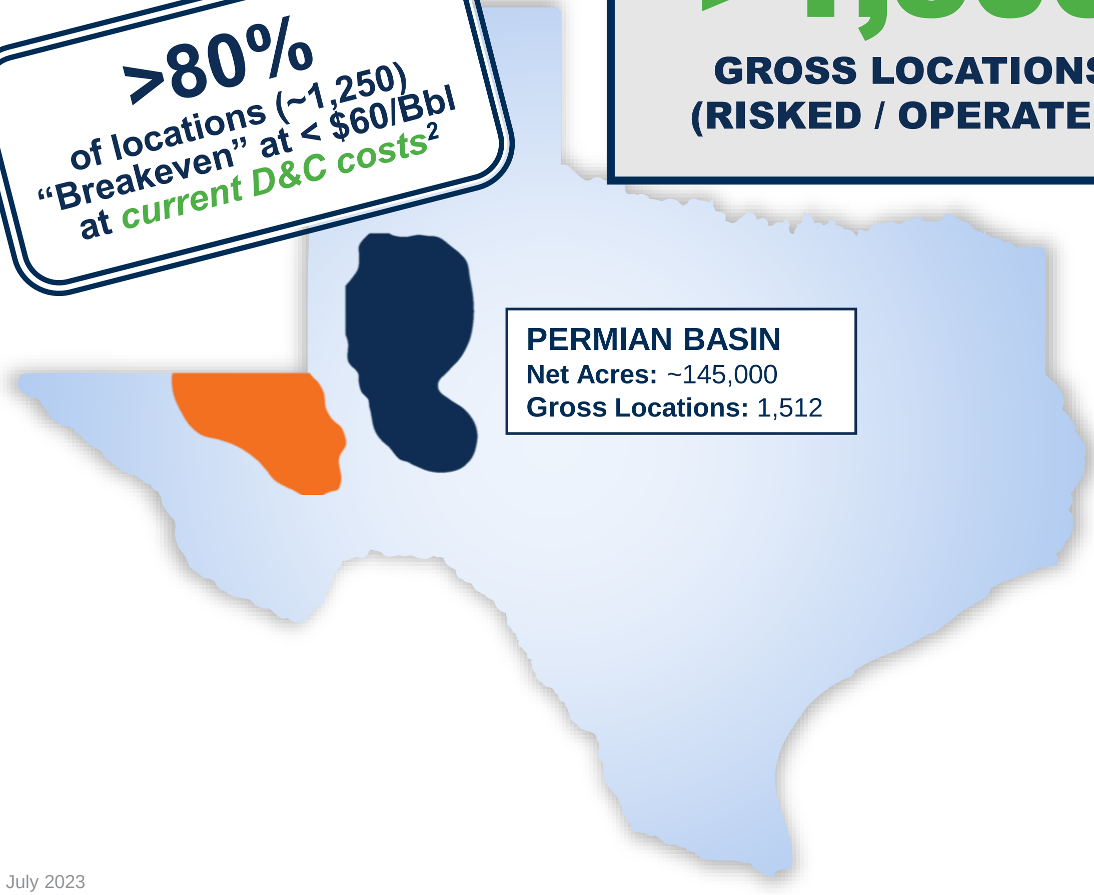
	Total	Avg. Lateral
BONE SPRING	219	9,452
WOLFCAMP A	478	8,314
WOLFCAMP B	251	8,624
WOLFCAMP C	99	8,838
TOTAL	**1,047**	**8,676**

MIDLAND BASIN OPERATED LOCATIONS IN CORE ZONES

	Total	Avg. Lateral
MIDDLE SPRABERRY	106	6,599
LOWER SPRABERRY	90	6,755
WOLFCAMP A	118	6,619
WOLFCAMP B	151	7,199
TOTAL	**465**	**6,829**

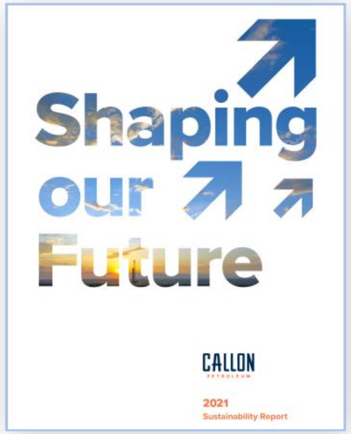
>80%
of locations (~1,250) "Breakeven" at < $60/Bbl at current D&C costs[2]

>1,500
GROSS LOCATIONS (RISKED / OPERATED)



1. Reflects Callon's Permian inventory position as of December 31, 2022 plus acquired inventory in Delaware Basin through a transaction that closed in July 2023
2. Assumes flat price deck of $60/Bbl, $30/Bbl of NGLs, and $3.00/MMBtu. "Breakeven" is defined as PV-10 positive

Peer Leading Sustainability Goals



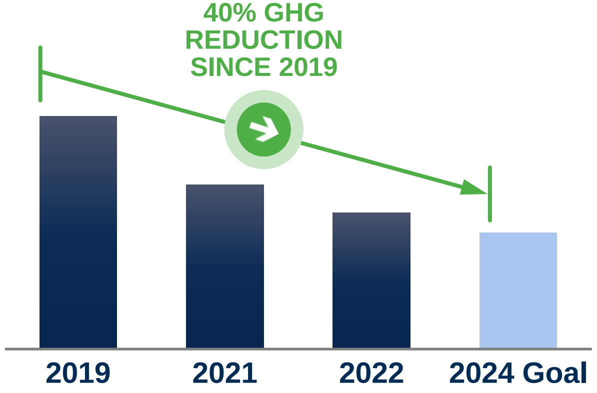
SUSTAINABILITY REPORT

For more information, please refer to:

Callon.com/sustainability

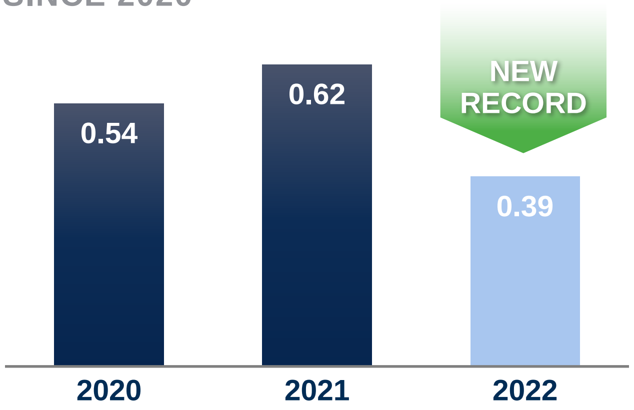
SCOPE 1 GHG INTENSITY

SINCE 2019



TOTAL REPORTABLE INCIDENT RATE

SINCE 2020



ENVIRONMENTAL TARGETS

50% Reduction in GHG intensity by 2024[1]

<0.2% Methane emissions by 2024

<1% Reduce Callon controlled flaring to less than 1% by 2024

1. Relative to 2019 baseline

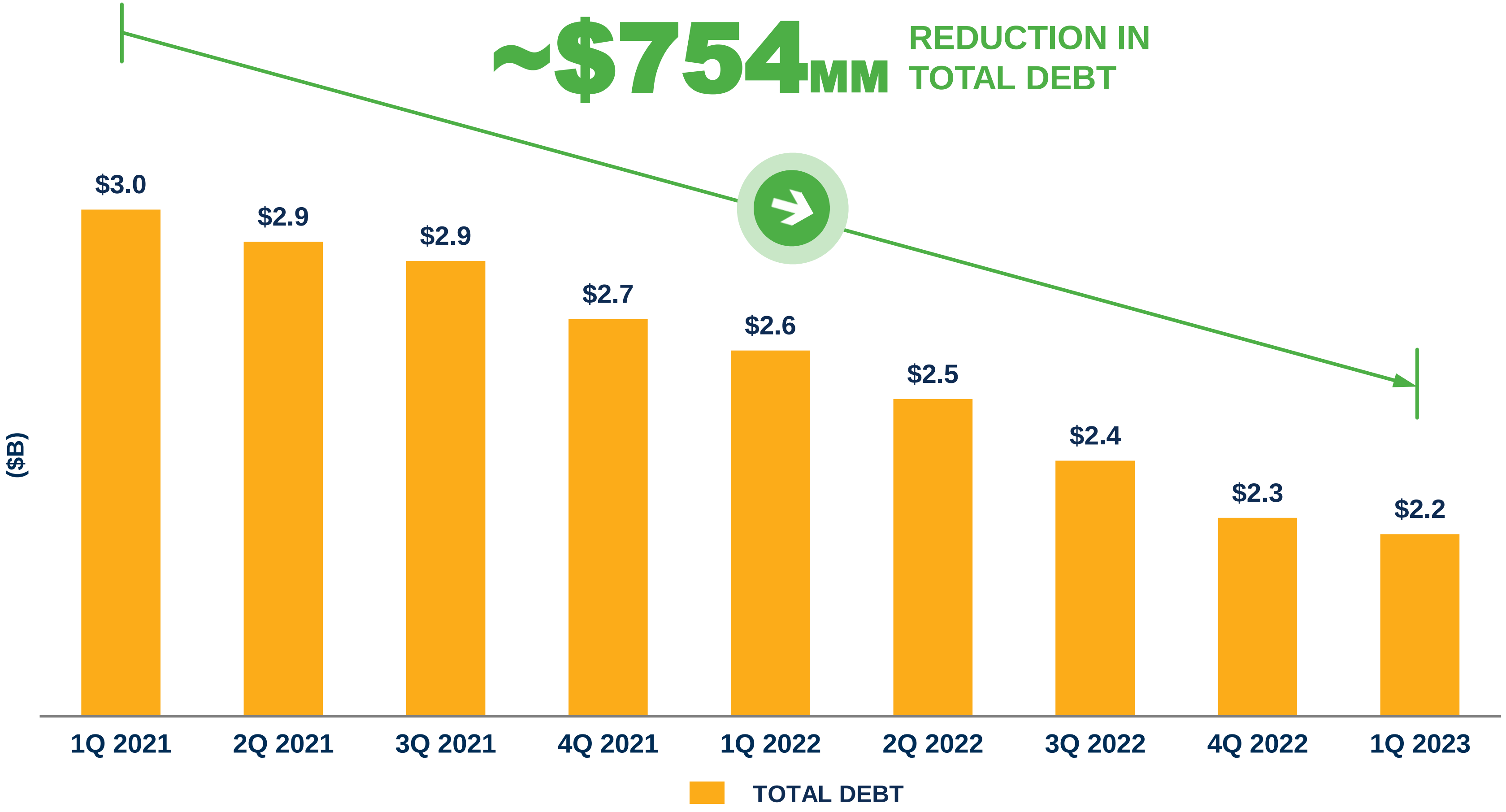
A Stronger Callon

- **FOCUSED PERMIAN OPERATIONS WITH SCALE**
- **ENHANCED CAPITAL STRUCTURE**
- **DECADE-PLUS PREMIUM INVENTORY**
- **LOWER COSTS, HIGHER MARGINS**
- **LAUNCHING SHAREHOLDER RETURN PROGRAM 3Q23**

APPENDIX

CALLON
PETROLEUM

Track Record of Rapid Deleveraging



~70%
REDUCTION IN LEVERAGE RATIO[1]

Eliminated
2ND LIEN NOTES

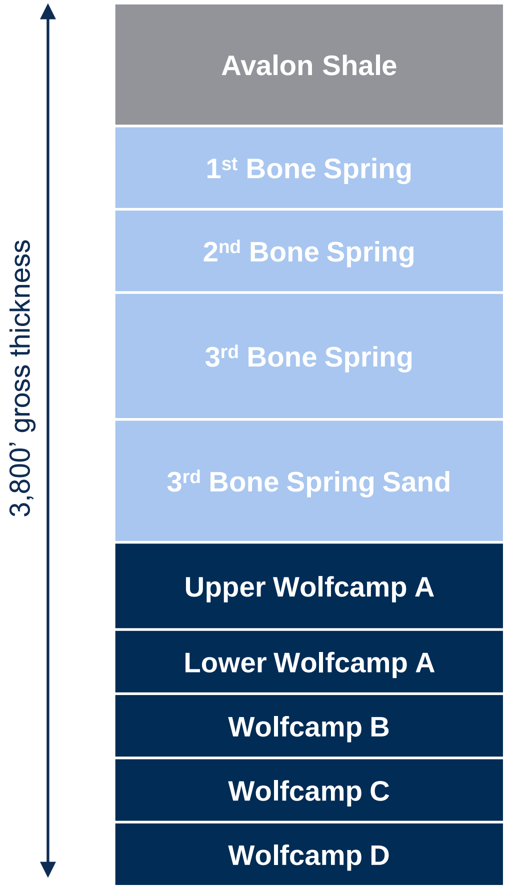
Extended
RBL MATURITY TO 2027

5+ Years
WTD. AVG. MATURITY OF TERM DEBT

1. Leverage ratio is calculated as net debt / LTM adjusted EBITDA as defined in our credit facility

Life of Field Co-Development Model

Delaware: ~100,000 net acres

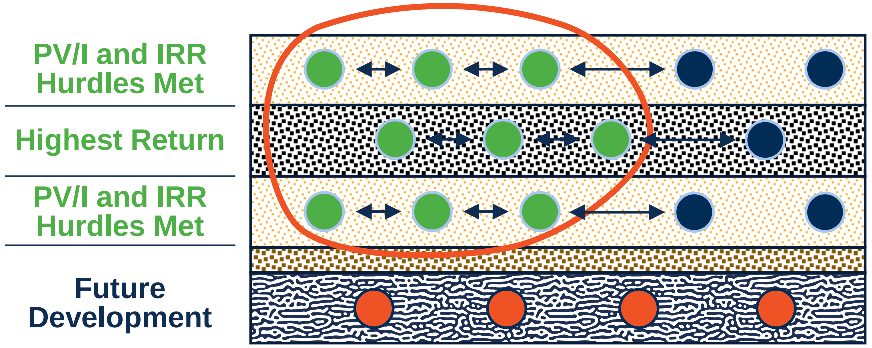


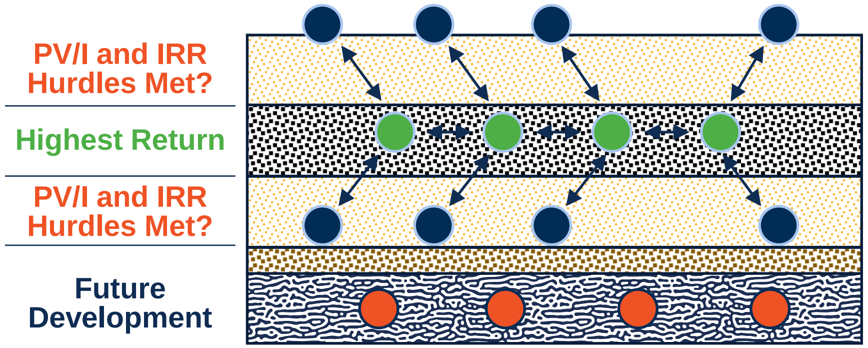
"LIFE OF FIELD" CO-DEVELOPMENT

- Scaled project sizes combined with shortened cycle times
- Reduces parent/child interference and reserve degradation
- Balances today's high-returns with future development economics

ALTERNATIVE: HIGH-GRADING OF ZONES

- ✗ Meaningful decline in capital efficiency over time and loss of economic inventory
- ✗ Increasingly complex parent and child interactions in "four dimensions"
- ✗ More exposure to offsetting frac impacts (both horizontal and vertical adjacent activity)





Parent wells | Child wells | Future Development

2023 Second Quarter Outlook

	2Q23
Total (MBoe/d)	**105 – 108**
Oil (MBbls/d)	63 – 65
Lease Operating ($/Boe)	8.00 – 8.50
GP&T ($/Boe)	2.85 – 2.95
Prod & Ad Val Taxes (% of revs)	6.5% – 7.0%
Cash G&A ($MM)	25 – 30
DD&A ($/Boe)	14.50 – 15.00
Exploration Expense ($MM)	1 – 3
Capital Expenditures ($MM)[1]	285 – 300
TILs (wells)	33 – 38

Note: Effective January 1, 2023, Callon changed accounting methods from full cost to successful efforts

1. Excludes land

Advantageous Debt Maturity Profile

Upgrades

FROM THREE CREDIT RATING AGENCIES IN 2022

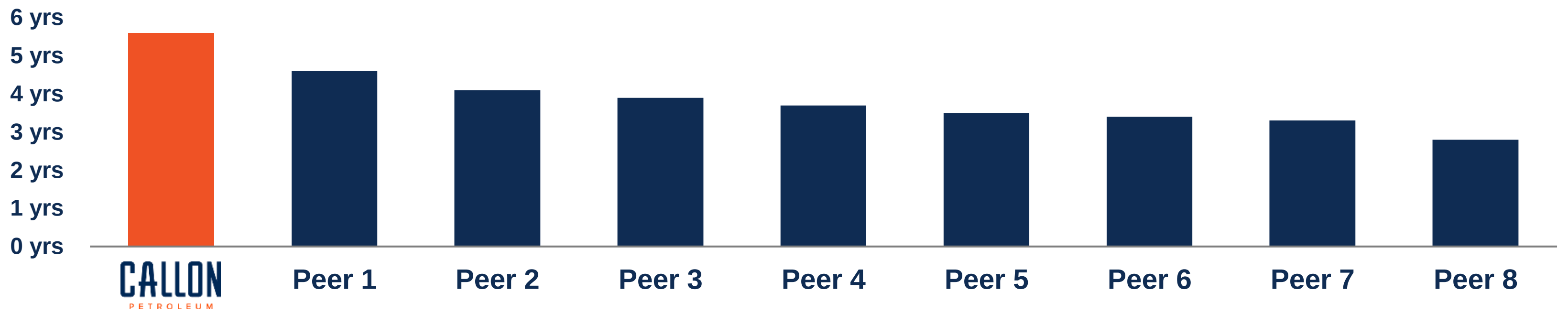
>$1B

LIQUIDITY[2] AFTER ASSET TRANSACTIONS & SENIOR NOTES REDEMPTION

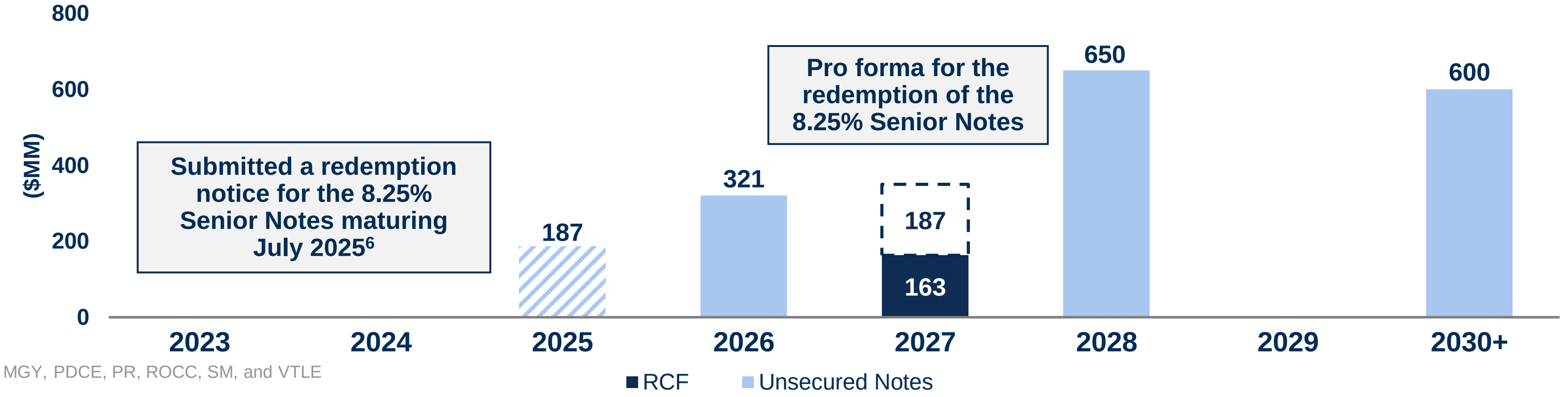
>3x

DEBT COVERAGE WITH YE22 VALUE OF PROVED DEVELOPED RESERVES[3]

Peer[1] Leading Weighted Average Maturity Profile[4]



Callon's Debt Maturity Profile[5]



1. Weighted average maturity as of March 31, 2023, peers include CIVI, MTDR, MGY, PDCE, PR, ROCC, SM, and VTLE
2. Consists of unused RBL commitments and cash
3. The PV-10 value of Callon's proved developed reserves is $7.1 billion
4. As of March 31, 2023; Callon as of 1Q23 PF for the redemption of 8.25% Senior Notes due 2025
5. Reflects debt reduction associated with the closing of the Percussion acquisition and Eagle Ford divestiture on July 3, 2023
6. The redemption of the 8.25% Senior Notes is expected to be completed in August 2023

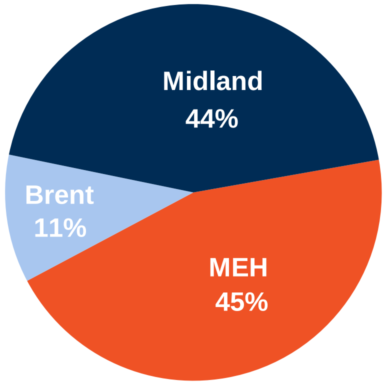
Increasing the Value Chain of Our Molecules

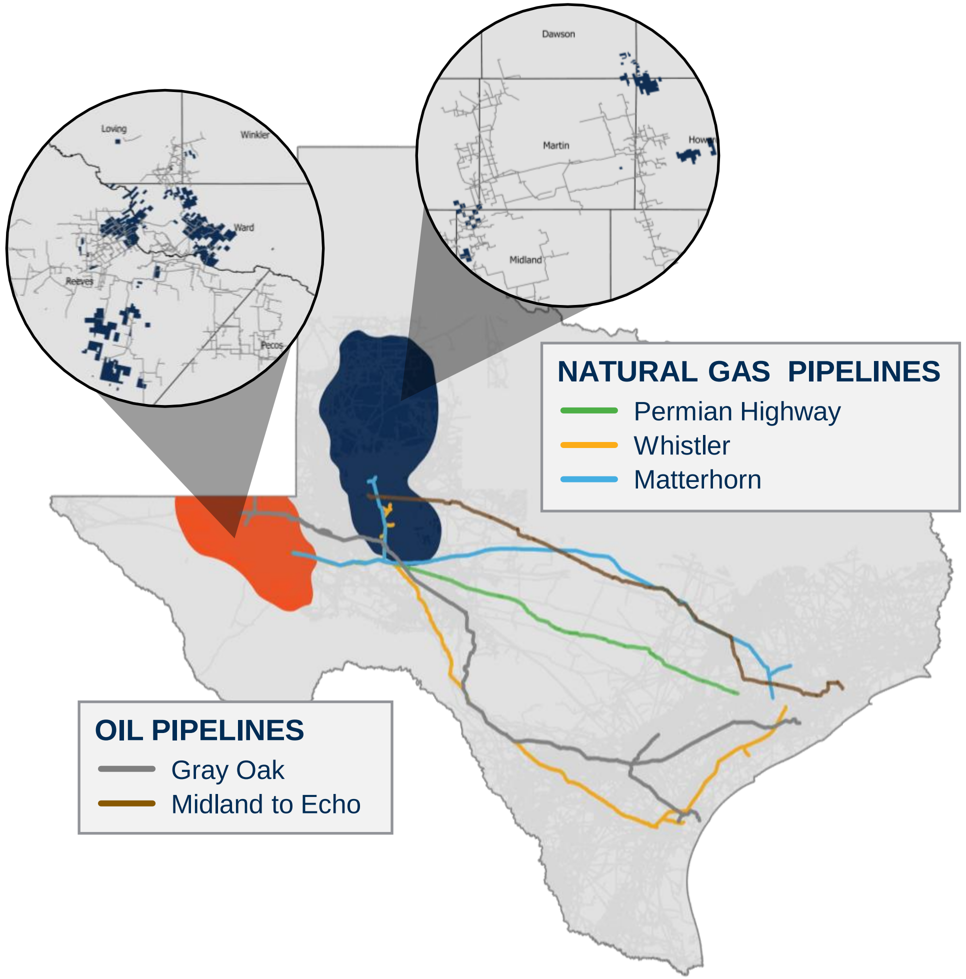
OIL

TAKEAWAY CAPACITY

- Portfolio approach employs a combination of in-basin sales and transportation arrangements to the Gulf Coast
- ~35,000 Bbls/d of transportation contracted on multiple long-haul pipelines to provide flow assurance and price diversification

PRICE EXPOSURE
2H23-24[2]



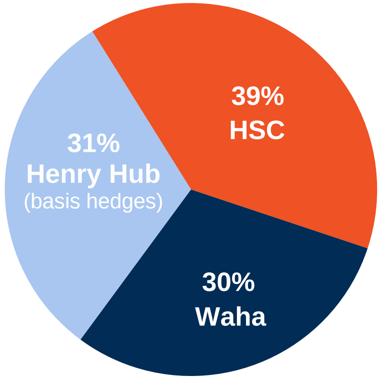


NATURAL GAS

TAKEAWAY CAPACITY

- "Take-in-kind" optionality in various gas gathering agreements
- ~75,000 MMBtu/d of transportation contracted on multiple long-haul pipelines[1]
- Entered into basis hedges from Waha and Houston Ship Channel to Henry Hub

PRICE EXPOSURE
2H23-24[2]

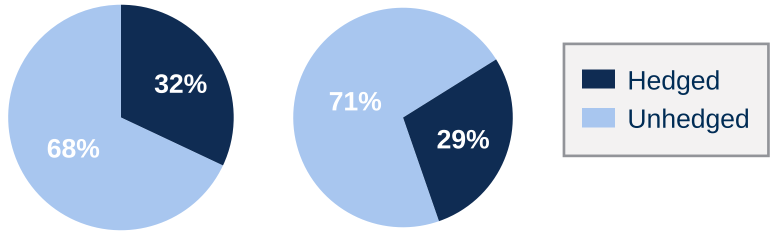


1. Dates assumed for long-haul transportation agreements are in-line with publicly available pipeline start-up information as of June 1, 2023
2. Projections based on current hedge book and development plan as of July 3, 2023

Derivative Positions

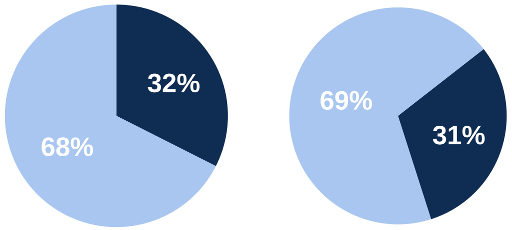
OIL VOLUMES[1]

2Q '23	2H '23



NATURAL GAS VOLUMES[1]

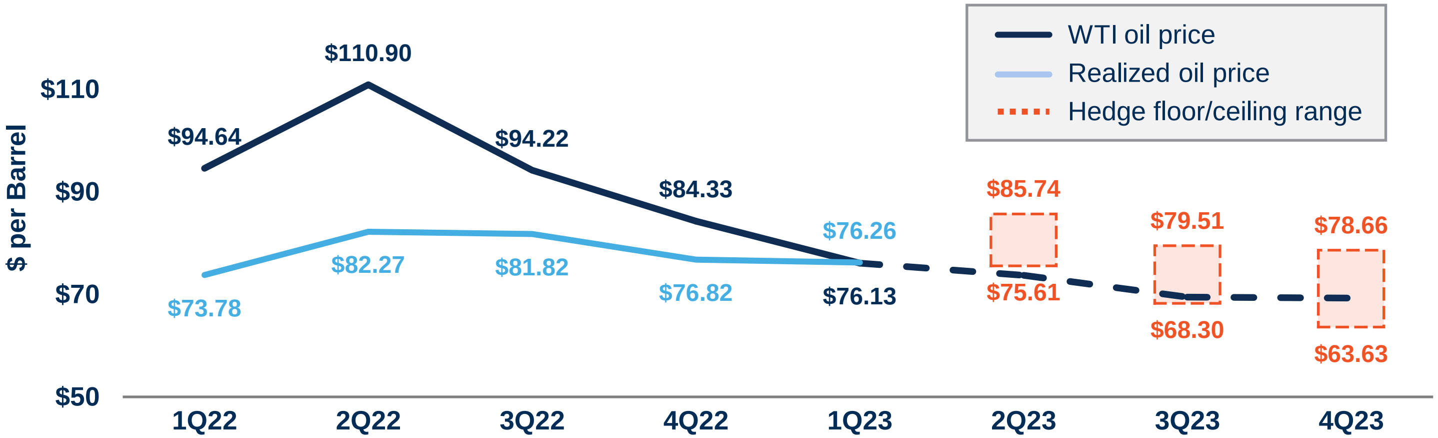
Summer '23	Winter '23



HEDGE GAINS / LOSSES BY QUARTER ($MM)

WTI Oil[2,4]	1Q23	2Q23	3Q23	4Q23
$60	$12	$25	$16	$7
$70	$12	$17	$2	($3)
$80	$12	$12	($7)	($8)
NYMEX Gas[3,4]	**1Q23**	**2Q23**	**3Q23**	**4Q23**
$2.50	$12	$17	$4	($2)
$3.00	$12	$17	$2	($3)
$3.50	$12	$17	$1	($3)

CALLON'S OIL PRICE REALIZATIONS[5]



2H23 CASH FLOW SENSITIVITIES ($MM)[2,3,4]

Annual Run Rate	Cash Flow from Operations
Oil: +$10	$63
Gas: +$0.50	$9

1. Based on consensus estimates as of June 26, 2023
2. Assumes flat natural gas price of $3.00/MMBtu; derivatives position as of July 3, 2023
3. Assumes flat oil price of $70/Bbl; derivatives position as of July 3, 2023
4. Assumes NGLs held flat at 32% of WTI; derivatives position as of July 3, 2023
5. Strip pricing as of June 26, 2023

Oil Hedges[1]

	2Q23	3Q23	4Q23	2Q23-4Q23	FY 2024
NYMEX WTI (Bbls, $/Bbl)					
Swaps					
Total Volumes	1,137,500	460,000	-	1,597,500	-
Total Daily Volumes	12,500	5,000	-	5,809	-
Avg. Swap Price	$79.58	$82.10	-	$80.30	-
Puts					
Total Volumes	-	368,000	368,000	736,000	-
Total Daily Volumes	-	4,000	4,000	2,676	-
Avg. Swap Price	-	$70.00	$70.00	$70.00	-
Collars					
Total Volumes	819,000	603,599	625,455	2,048,054	-
Total Daily Volumes	9,000	6,561	6,798	7,447	-
Avg. Short Call Strike	$91.93	$85.81	$85.34	$88.12	-
Avg. Long Put Strike	$73.22	$67.62	$67.35	$69.78	-
Three-Way Collars					
Total Volumes	455,000	493,028	541,528	1,489,556	3,963,023
Total Daily Volumes	5,000	5,359	5,886	5,417	10,828
Avg. Short Call Strike	$90.00	$69.38	$70.95	$79.44	$78.86
Avg. Long Put Strike	$70.00	$55.00	$55.00	$62.00	$58.16
Avg. Short Put Strike	$50.00	$45.00	$45.00	$47.33	$48.16
Total WTI Volume Hedged (Bbls)	2,411,500	1,924,627	1,534,983	5,135,110	3,963,023
Average WTI Ceiling Strike ($/Bbl)	$85.74	$79.51	$78.66	$83.17	$78.86
Average WTI Floor Strike ($/Bbl)	$75.61	$68.30	$63.63	$70.70	$58.16
WTI CMA Roll (Bbls, $/Bbl)					
Swaps					
Total Volumes	-	673,535	838,828	1,512,363	-
Total Daily Volumes	-	7,321	9,118	5,500	-
Avg. Swap Price	-	$0.29	$0.30	$0.30	-

1. As of July 3, 2023

Natural Gas Liquids Hedges[1]

	2Q23	3Q23	4Q23	2Q23-4Q23	FY 2024
NATURAL GAS LIQUIDS (Bbls, $/Bbl)					
MBV Ethan Purity					
Total Volumes	-	35,333	35,095	70,428	-
Total Daily Volumes	-	384	381	877	-
Avg. Swap Price	-	$9.66	$9.66	$9.66	-
MBV Propane EPC					
Total Volumes	-	36,077	35,754	71,831	-
Total Daily Volumes	-	392	389	1,026	-
Avg. Short Call Strike	-	$31.37	$31.37	$31.37	-
MBV n-Butane EPC					
Total Volumes	-	31,137	33,470	64,606	72,105
Total Daily Volumes	-	338	364	235	197
Avg. Swap Price	-	$35.55	$35.65	$35.60	$33.18
MBV i-Butane EPC					
Total Volumes	-	10,174	10,967	21,141	23,462
Total Daily Volumes	-	111	119	77	64
Avg. Swap Price	-	$35.42	$35.53	$35.47	$33.18
MBV Natural Gasoline EPC					
Total Volumes	-	40,405	43,105	83,510	-
Total Daily Volumes	-	439	469	304	-
Avg. Swap Price	-	$56.28	$56.34	$56.31	-

1. As of July 3, 2023

Natural Gas Hedges[1]

	2Q23	3Q23	4Q23	2Q23-4Q23	FY 2024
NYMEX HENRY HUB (MMBtu, $/MMBtu)					
Swaps					
Total Volumes	2,730,000	1,840,000	620,000	5,190,000	-
Total Daily Volumes	30,000	20,000	6,739	18,873	-
Avg. Swap Price	$3.70	$3.00	$3.00	$3.37	-
Collars					
Total Volumes	1,820,000	1,572,296	2,201,102	5,593,398	8,598,555
Total Daily Volumes	20,000	17,090	23,925	20,340	23,493
Avg. Short Call Strike	$5.50	$5.21	$5.37	$5.37	$3.89
Avg. Long Put Strike	$3.75	$3.63	$3.14	$3.48	$3.00
Total NYMEX Volume Hedged (MMBtu)	4,550,000	3,412,296	2,821,102	10,783,398	8,598,555
Average NYMEX Ceiling Strike ($/MMBtu)	$4.42	$4.02	$4.85	$4.41	$3.89
Average NYMEX Floor Strike ($/MMBtu)	$3.72	$3.29	$3.11	$3.43	$3.00
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)					
Swaps					
Total Volumes	2,730,000	3,680,000	2,460,000	8,870,000	7,320,000
Total Daily Volumes	30,000	40,000	26,739	32,255	20,000
Avg. Swap Price	($1.02)	($1.25)	($1.49)	($1.24)	($1.06)
HOUSTON SHIP CHANNEL DIFFERENTIAL (MMBtu, $/MMBtu)					
Swaps					
Total Volumes	2,730,000	2,760,000	2,760,000	8,250,000	14,640,000
Total Daily Volumes	30,000	30,000	30,000	30,000	40,000
Avg. Swap Price	($0.29)	($0.29)	($0.29)	($0.29)	($0.42)

1. As of July 3, 2023

CALLON PETROLEUM

Non-GAAP Adjusted Income[1]

($ thousands, except per share)	1Q 23
Net income	**$220,638**
Gain on derivative contracts	(25,645)
Gain on commodity derivative settlements, net	12,012
Non-cash expense related to share-based awards	1,881
Merger, integration, transaction and other	(6,414)
Tax effect on adjustments above[2]	3,815
Change in valuation allowance	(86,383)
Adjusted income	**$119,904**
Net income per diluted share	**$3.57**
Adjusted income per diluted share	**$1.94**
Basic weighted average common shares outstanding	61,625
Diluted weighted average common shares outstanding (GAAP)	61,874

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures
2. Calculated using the federal statutory rate of 21%

Non-GAAP Adjusted EBITDAX[1]

($ thousands, except per Boe)	FY 2021	1Q 22	2Q 22	3Q 22	4Q 22	FY 2022	1Q 23
Net income (loss)	**$133,561**	**($7,715)**	**$303,251**	**$502,039**	**$221,868**	**$1,019,443**	**$220,638**
(Gain) loss on derivative contracts	522,300	358,300	81,648	(134,850)	25,855	330,953	(25,645)
Gain (loss) on commodity derivative settlements, net	(423,306)	(133,476)	(184,558)	(105,006)	(44,380)	(467,420)	12,012
Non-cash expense (benefit) related to share-based awards	25,857	6,043	(3,357)	1,741	3,615	8,042	1,881
Impairment of oil and gas properties	52,295	-	-	-	2,201	2,201	-
Merger, integration, transaction and other	21,944	(13)	1,051	2,861	(485)	3,414	(6,414)
Income tax (benefit) expense	180	(87)	3,240	3,383	7,286	13,822	(50,695)
Interest expense, net	201,659	47,096	46,995	46,929	46,772	187,792	46,306
Depreciation, depletion and amortization	388,612	113,643	115,956	129,895	134,735	494,229	125,965
Exploration	6,470	1,885	2,410	2,942	2,466	9,703	2,232
Loss on extinguishment of debt	41,040	-	42,417	-	3,241	45,658	-
Adjusted EBITDAX	**$970,612**	**$385,676**	**$409,053**	**$449,934**	**$403,174**	**$1,647,837**	**$326,280**
Primexx EBITDA[2]	$170,923	-	-	-	-	-	-
Total Production (MBoe)	34,894	9,239	9,162	9,873	9,779	38,053	8,979
Net Income (Loss) per Boe	**$3.83**	**($0.84)**	**$33.10**	**$50.85**	**$22.69**	**$26.79**	**$24.57**
Adjusted EBITDAX per Boe	**$27.82**	**$41.74**	**$44.65**	**$45.57**	**$41.23**	**$43.30**	**$36.34**

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures
2. Represents EBITDA from January 1 through September 30, 2021 prior to closing on transaction on October 1

Non-GAAP Adjusted Free Cash Flow[1]

($ thousands)	1Q 22	2Q 22	3Q 22	4Q 22	FY 2022	1Q 23
Net cash provided by operating activities	**$247,821**	**$336,085**	**$437,780**	**$333,987**	**$1,355,673**	**$247,913**
Changes in working capital and other	125,799	29,007	(69,388)	13,781	99,199	18,869
Changes in accrued hedge settlements	(31,951)	1,839	40,590	15,816	26,294	12,791
Merger, integration and transaction	769	-	-	-	769	-
Cash flow from operations before net changes in working capital	**$342,438**	**$366,931**	**$408,982**	**$363,584**	**$1,481,935**	**$279,573**
Capital expenditures	**$168,270**	**$176,611**	**$303,268**	**$200,539**	**$848,688**	**$204,900**
Increase (decrease) in accrued capital expenditures	(8,897)	65,110	(42,247)	(1,870)	12,096	67,460
Capital expenditures before accruals	**$159,373**	**$241,721**	**$261,021**	**$198,669**	**$860,784**	**$272,360**
Adjusted Free Cash Flow	**$183,065**	**$125,210**	**$147,961**	**$164,915**	**$621,151**	**$7,213**

1. See "Important Disclosures" slide for additional information related to Non-GAAP Financial Measures

Non-GAAP Net Debt and PV-10 Reconciliation[1]

($ millions)	12/31/21	3/31/22	6/30/22	9/30/22	12/31/22	3/31/23
Total debt	**$2,694**	**$2,623**	**$2,516**	**$2,373**	**$2,241**	**$2,204**
Unamortized premiums, discount, and deferred loan costs, net	29	27	21	21	20	19
Adjusted total debt	**$2,723**	**$2,650**	**$2,537**	**$2,394**	**$2,261**	**$2,223**
Less: Cash and cash equivalents	10	4	6	4	3	3
Net Debt	**$2,713**	**$2,646**	**$2,531**	**$2,390**	**$2,258**	**$2,220**

($ millions)	2022
Standardized measure of discounted future net cash flows	**$9,004**
Add: present value of future income taxes discounted at 10% per annum	1,531
Total proved reserves - PV-10	**$10,535**

1. See “Important Disclosures” slide for additional information related to Supplemental Non-GAAP Financial Measures