2023 INVESTOR PRESENTATION

FEBRUARY 2023

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 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 therefof, 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 free cash flow," "adjusted EBITDA," "adjusted EBITDA per Boe," "adjusted discretionary cash flow," "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 adjusted EBITDA less operational capital expenditures (accrual), capitalized cash interest, capitalized cash G&A (which excludes capitalized expense related to share-based awards), and cash interest expense, net. 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, or as an alternative to net income (loss).

Callon calculates adjusted EBITDA 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 evaluated oil and gas properties, non-cash share-based compensation expense, merger, integration and transaction expense, (gain) loss on extinguishment of debt, and certain other expenses. Adjusted EBITDA 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 EBITDA 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 EBITDA excludes some, but not all, items that affect net income (loss) and may vary among companies, the adjusted EBITDA presented in this presentation 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), adjusted discretionary cash flow (non-GAAP), net debt and adjusted EBITDA (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?*

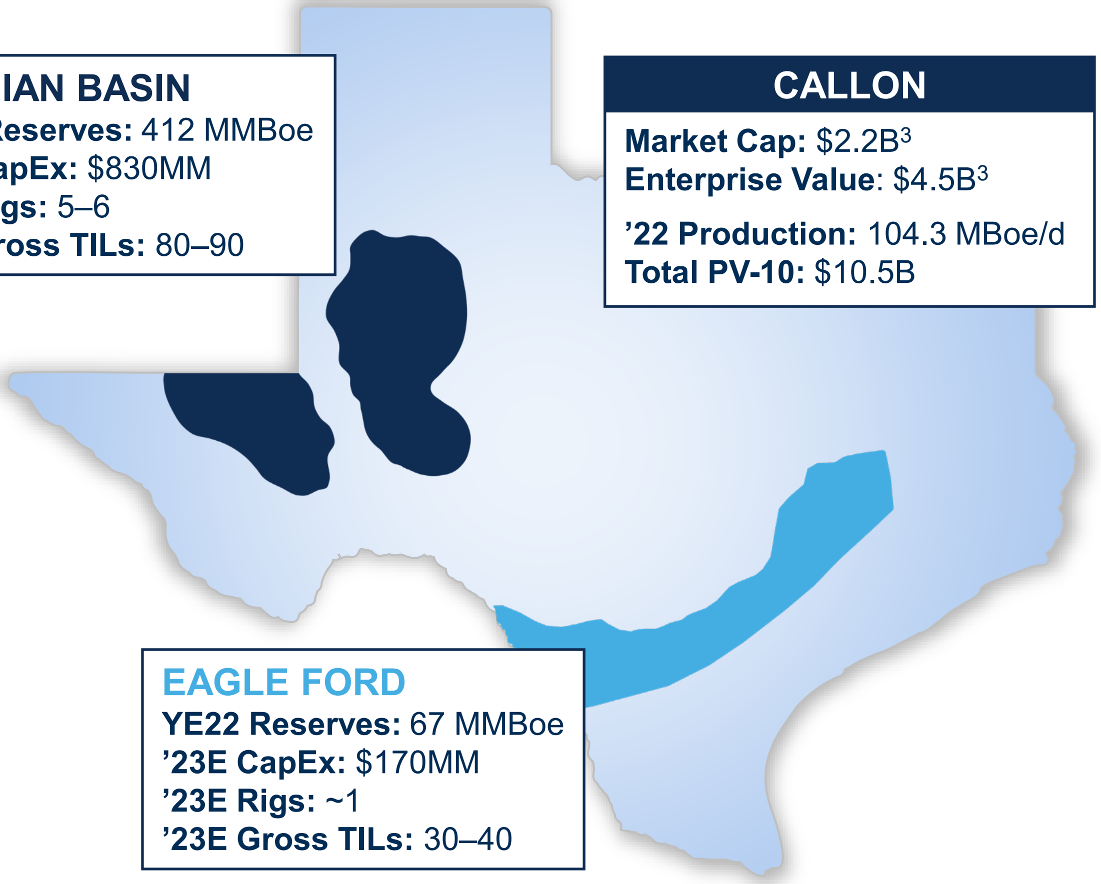
HIGH-RETURN ASSET PORTFOLIO
- >10-year inventory at <$60/Bbl in premier oil basins in Texas
- **>1,500 risked locations in core zones**

DISCIPLINED "LIFE OF FIELD" CO-DEVELOPMENT MODEL
- Improves long-term capital efficiency
- **29% y/y increase in Delaware Basin well productivity**[1]

RETURNS-DRIVEN STRATEGY DRIVES ADJ. FCF
- Expect to generate **>$2.75 billion in adj. FCF** from 2023–27[2]
- 2022 ROCE[4] of >25%

RAPID DEBT REDUCTION
- **Reduced leverage ratio by 70%**[5] & total debt >$700MM since 1Q21
- Projected to **reach key $2B debt milestone in 2H23** at strip commodity prices[6]

ESG LEADERSHIP
- GHG intensity tied to long-term compensation
- **~50% GHG reduction by 2024**



PERMIAN BASIN
YE22 Reserves: 412 MMBoe
'23E CapEx: $830MM
'23E Rigs: 5–6
'23E Gross TILs: 80–90

CALLON
Market Cap: $2.2B[3]
Enterprise Value: $4.5B[3]
'22 Production: 104.3 MBoe/d
Total PV-10: $10.5B

EAGLE FORD
YE22 Reserves: 67 MMBoe
'23E CapEx: $170MM
'23E Rigs: ~1
'23E Gross TILs: 30–40

1. Based on data from Enverus. Delaware Basin wells with nine months of production history in 2022
2. Free cash flow forecast assumes $80/Bbl WTI and $3.50/MMBtu Henry Hub
3. Market capitalization and enterprise value as of February 17, 2023
4. Calculated as EBIT divided by average total assets minus average current liabilities
5. Leverage ratio is calculated as net debt / LTM adjusted EBITDA as defined in our credit facility
6. Bloomberg WTI oil price and NYMEX natural gas prices as of February 17, 2023

2023 Value Drivers

2023E PRODUCTION

104–107 MBoe/d

>60% Oil
>80% Liquids

IMPROVING CYCLE TIMES

~20%

Reduction in project cycle times

2023 CAPITAL BUDGET

$1.0B

>80% Permian

~60%

Reinvestment rate[1]

CONTINUED DEBT REDUCTION

$2.0B

Projected to achieve key debt milestone in 2H23 at strip[2]

ADJUSTED FREE CASH FLOW

>$2.75B

Estimated for 2023-27[3]

~125%

Of equity market cap.[4]

CONSISTENT WELL RETURNS

~70% IRR

Average '23 project level returns[3]

1. Calculated as 2023 total capex divided by consensus 2023E adjusted EBITDA. FactSet consensus 2023E adjusted EBITDA was $1.63 billion as of February 3, 2023
2. Based on Bloomberg WTI oil price and NYMEX natural gas prices as of February 10, 2023
3. Assumes price deck of $80/Bbl WTI and $3.50/MMBtu Henry Hub. Calculation excludes land, seismic, and facility costs
4. Market capitalization as of February 17, 2023

Execution Drove Record Adjusted Free Cash Flow in 2022

DELIVERED COMPANY RECORD $623MM ADJUSTED FCF[1]

- 3 consecutive years of increases in adjusted EBITDA[1] per Boe
- Reinvestment rate[2] of <60%
- Y/Y production growth of 9%

INTEGRATED DELAWARE SOUTH ASSETS

- Increased production ~11%[3]
- Reduced LOE per Boe ~20%[3]

STRENGTHENED BALANCE SHEET

- Reduced leverage ratio by 1.0x[4]
- Paid down $462MM in debt

REDUCED EMISSIONS

- On track to achieve ~50% GHG reduction by 2024[5]

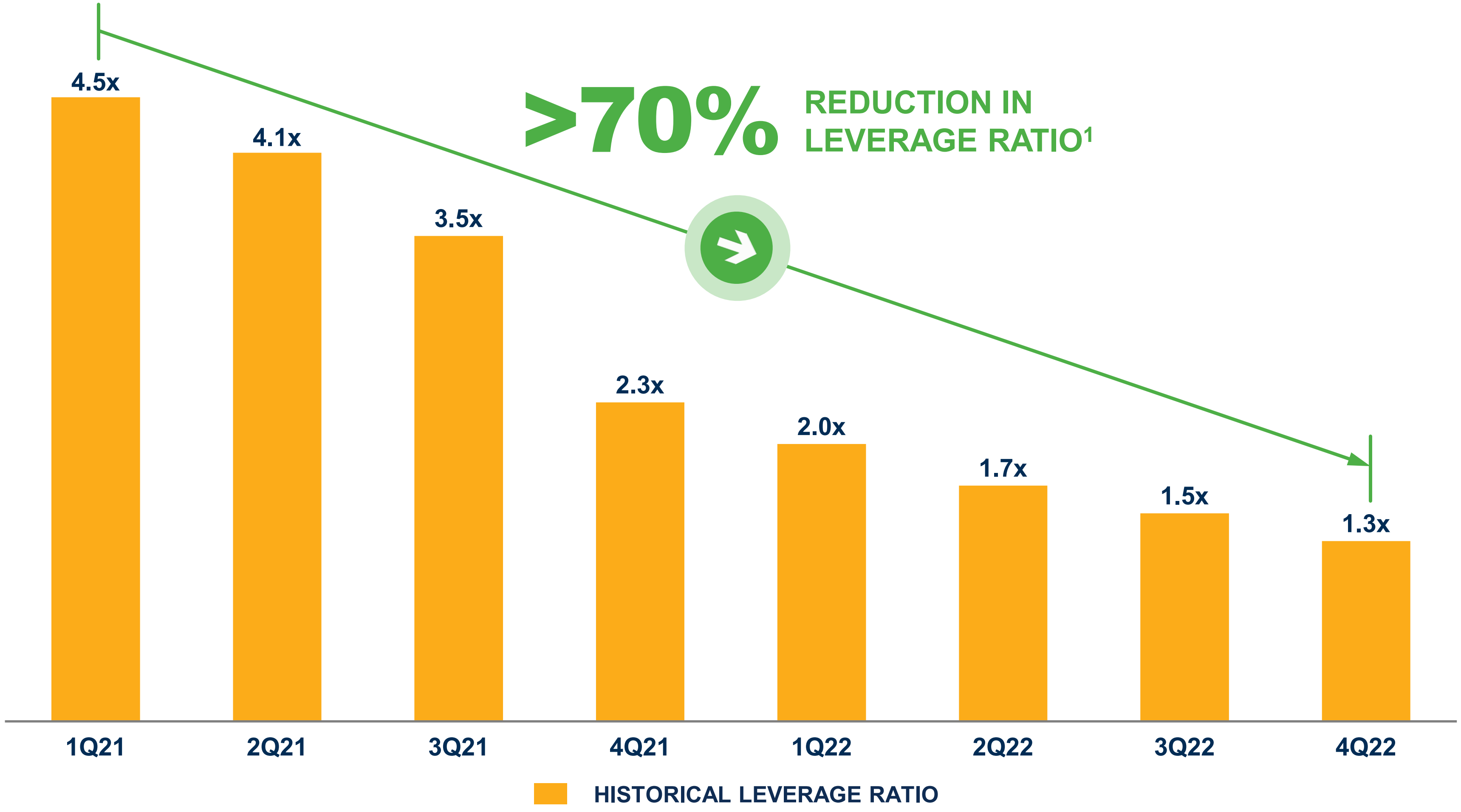
	4Q22	FY22
ADJUSTED CASH FLOW PER SHARE[6]	$6.08	$25.51
ADJUSTED FREE CASH FLOW (MM)	$165	$623
ADJUSTED EBITDA (MM)	$412	$1,683
DEBT REDUCTION (MM)	$133	$462

4Q22 / FY22 PRODUCTION
106 / 104
MBoe/d

4Q22 / FY22 CAPEX[7]
$234 / $998
(MM)

1. Adjusted free cash flow, adjusted EBITDA and adjusted EBITDA per Boe are non-GAAP financial measures. Please see the appendix for the reconciliation
2. Reinvestment rate is calculated by dividing operational capital expenditures by cash from operating activities
3. Increase reflects 4Q22 over 4Q21
4. Leverage ratio is calculated as net debt / LTM adjusted EBITDA as defined in our credit facility
5. The reduction rate is based on 2019's GHG emission levels
6. Defined as adjusted discretionary cash flow divided by weighted average shares outstanding. Adjusted discretionary cash flow is a non-GAAP financial measure. Please see the appendix for the reconciliation
7. Capital expenditures reflects capital spending as reported under full cost accounting which includes operational capex as well as capitalized interest and G&A, but excludes land, seismic, and ARO

Track Record of Rapid Deleveraging



~$715MM
DEBT REDUCTION SINCE 1Q21

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

Disciplined Capital Allocation Framework

CASH FLOW FROM OPERATIONS

- **Invest** in deep, differentiated project inventory
- Planning **modest production growth** through disciplined reinvestments
- Adhere to **"Life of Field"** co-development model

60%

2023E REINVESTMENT RATE[1]

EXPECTED USES OF FREE CASH FLOW

Deleveraging / Enhance Liquidity	Shareholder Returns	Optionality for Reinvestment That Improves Returns

NEAR-TERM PRIORITIES

- Generate FCF with high-return '23 program
- Reach key $2B debt milestone in 2H23

NEXT STEPS

- Expect to initiate share repurchase program
- Ongoing debt reduction: targeting optimal debt <$1.5 billion and leverage <1.0x
- Optionality for drilling program
- Evaluate additional return of capital options

1. Calculated as 2023 total capex divided by consensus 2023E adjusted EBITDA. FactSet consensus 2023E adjusted EBITDA was $1.63 billion as of February 3, 2023

Progress to Initiate Return of Capital Program

- [x] **Retired Second Lien Notes**
- [x] **Retired Unsecured Notes Due in 2024**
- [x] **Extended Credit Facility Maturity**
- [ ] **Reduce Debt to $2B**
- [ ] **Initiate Return of Capital Program**
- [ ] **Reduce Debt to <$1.5B and Drive Leverage to <1.0x**

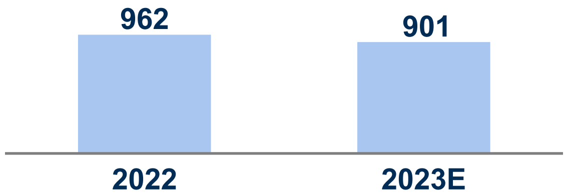
$2.0B Debt

- Absolute debt is our financial trigger for initiation of shareholder return program
- Absolute debt level is consistent measure of leverage through periods of commodity price volatility
- Expect to achieve by 2H23 at current strip prices
- Focus on continued paydown to reach optimal gross debt (excluding cash balances) of <$1.5 billion and leverage to <1.0x

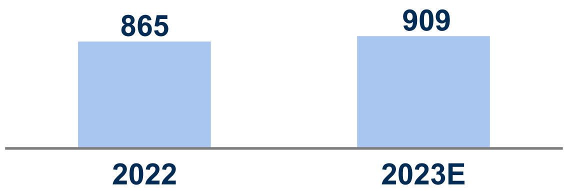
2023 Capital Efficiency: Structural Improvements

Similar Levels of D&C Activity…

TOTAL DRILLED LATERAL
THOUSAND FEET

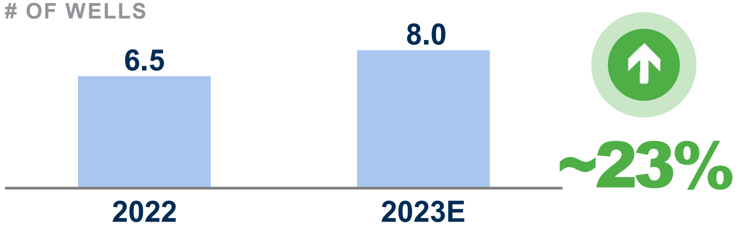


TOTAL COMPLETED LATERAL
THOUSAND FEET

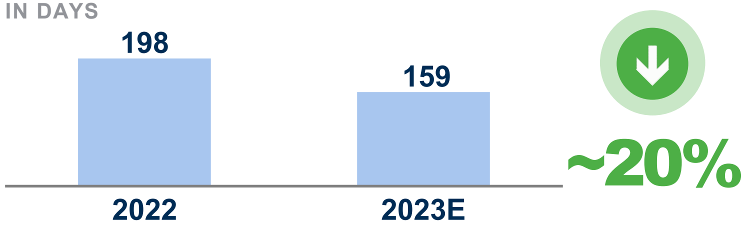


…Combined with Efficiency Initiatives…

PROJECT SIZE
OF WELLS

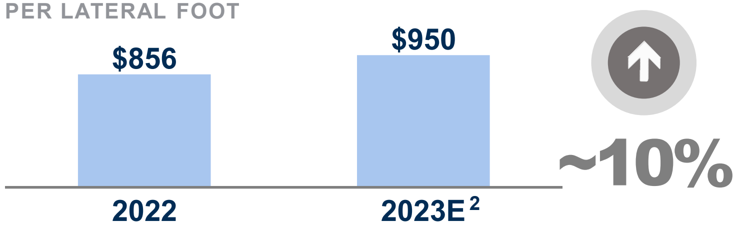


PROJECT D&C CYCLE TIMES[1]
IN DAYS

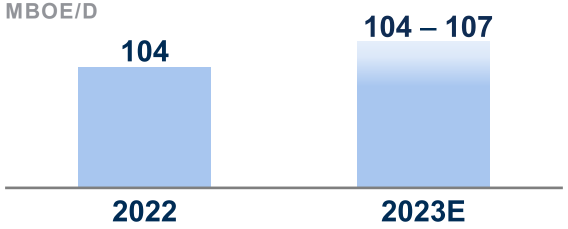


…Yields Capital Efficient Growth

D&C COSTS
PER LATERAL FOOT



TOTAL PRODUCTION
MBOE/D



PROGRAM HIGHLIGHTS

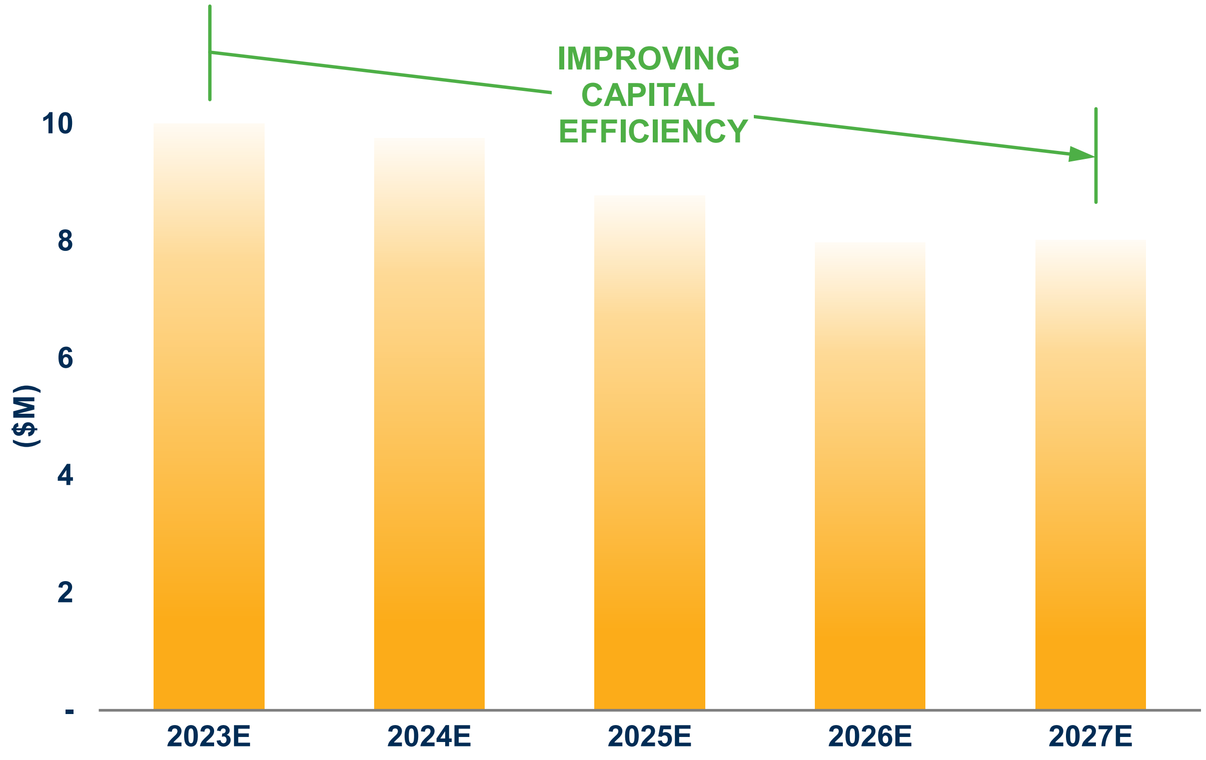
- Increasing use of simultaneous D&C operations combined with completion efficiencies
- Improved cycle times benefit capital efficiency
- Efficiencies expected to help offset Y/Y D&C service cost inflation
- Avg. expected project IRR ~70%
- Increasing 2024 production flexibility with modest DUC build in 2023

1. Calculated by taking the number of days from the first spud on a project to last week completed on the project
2. Assumes Eagle Ford D&C cost of $730/ft, Delaware Basin D&C cost of $1,050/ft, and Midland Basin D&C cost of $790/ft

"Life of Field" Co-Development Model Improves Long-Term Capital Efficiency

5-YEAR DEVELOPMENT SCENARIOS

TOTAL CAPEX / AVERAGE 12-MONTH BOE PER DAY[1]



BASELINE PRODUCTION GROWTH CAGR OF 2% - 4%

"LIFE OF FIELD" CO-DEVELOPMENT MODEL

Multi-zone co-development with parent wells and large projects optimizes NPV:

- Scaled project sizes combined with shortened cycle times
- Reduces parent/child interference and reserve degradation
- Pressure-managed flowback improves recoveries, reduces production variability
- Balances today's high-returns with future development economics
- More consistent capital efficiency profile over time

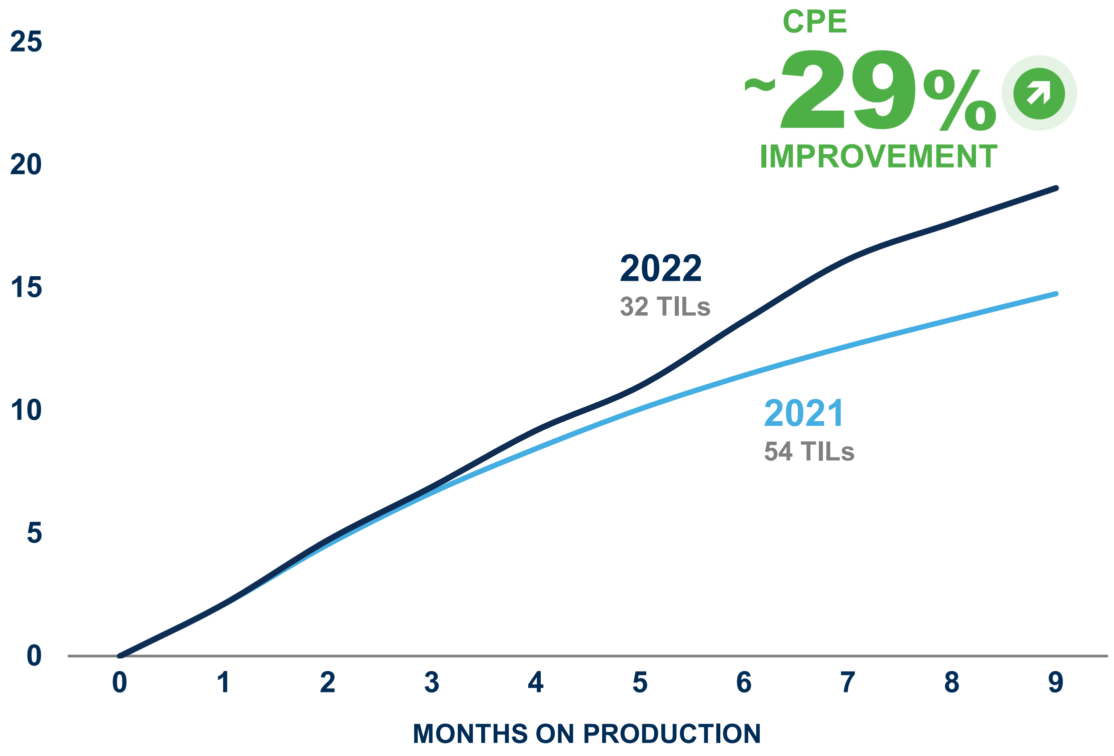
1. Defined as D&C plus facilities capital spending divided by forecasted average annual production rate. Assumes current D&C cost structure held constant

"Life of Field" Co-Development Model Enhances Long-Term Returns & Well Productivity

CALLON'S INCREASING WELL PRODUCTIVITY[1]

AVERAGE DELAWARE BASIN CUMULATIVE PRODUCTION BY MONTH

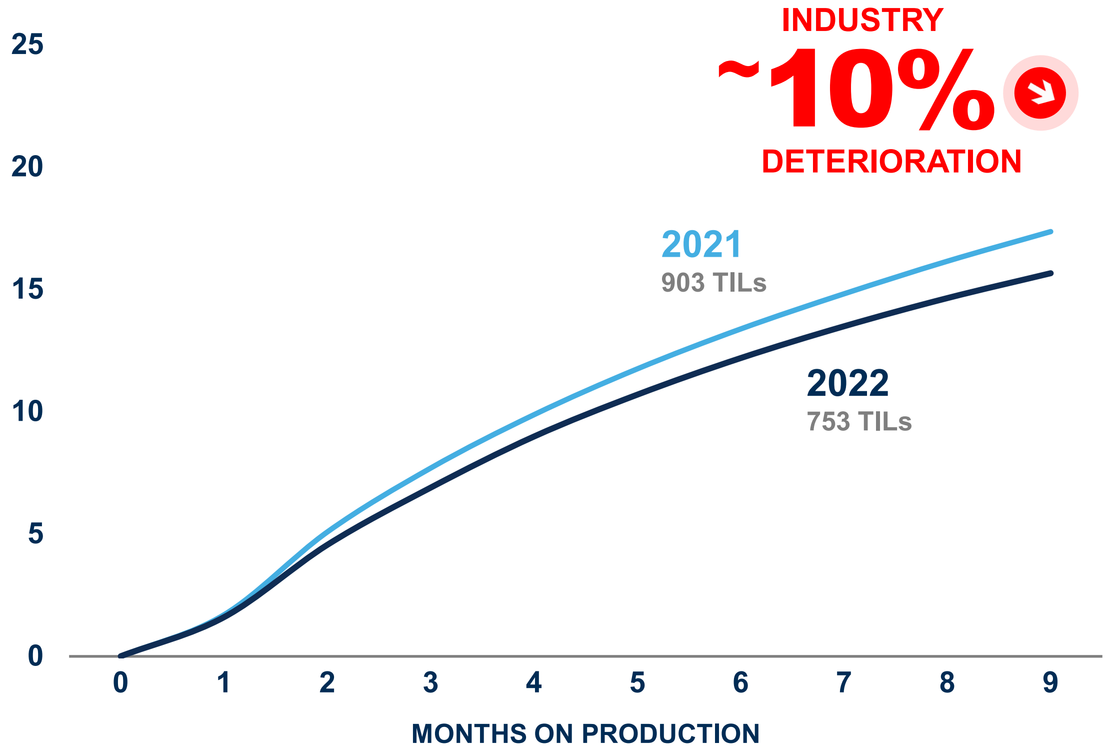
MBbl per 1,000 ft



INDUSTRY'S DEGRADING WELL PRODUCTIVITY[1,2]

AVERAGE DELAWARE BASIN CUMULATIVE PRODUCTION BY MONTH

MBbl per 1,000 ft



1. Represents wells placed online with 9 months of production history
2. Based on data from Enverus as of February 7, 2023

Proven Consolidator: Primexx Case Study

2022 DELAWARE SOUTH ACCOMPLISHMENTS

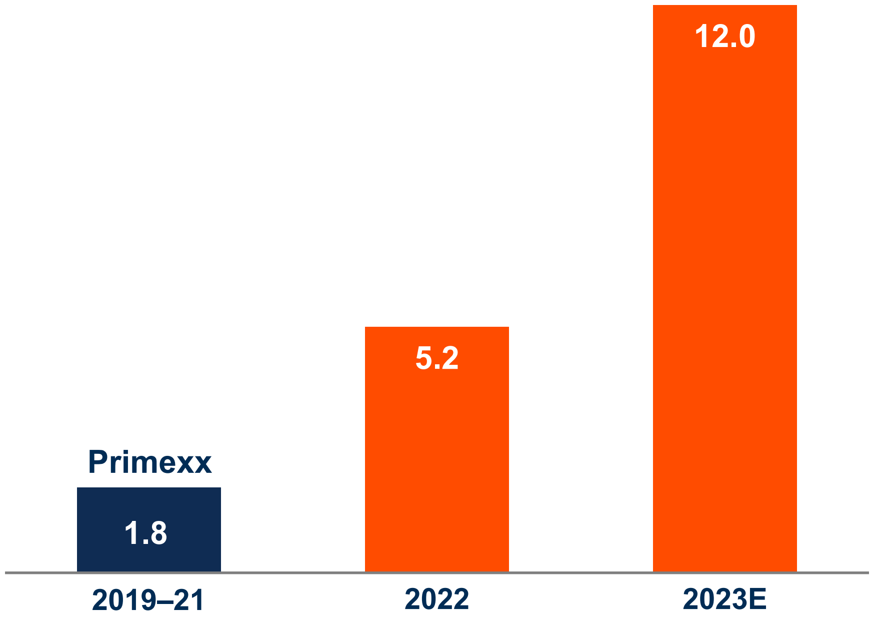
~11%
Y/Y PRODUCTION INCREASE[1]

26
WELLS BROUGHT ONLINE

~20%
Y/Y DECREASE IN LOE PER BOE[1]

>40%
REDUCTION IN GAS FLARE RATE[2]

DELAWARE SOUTH OPTIMIZATION
(AVG. # WELLS/PROJECT)



>50%

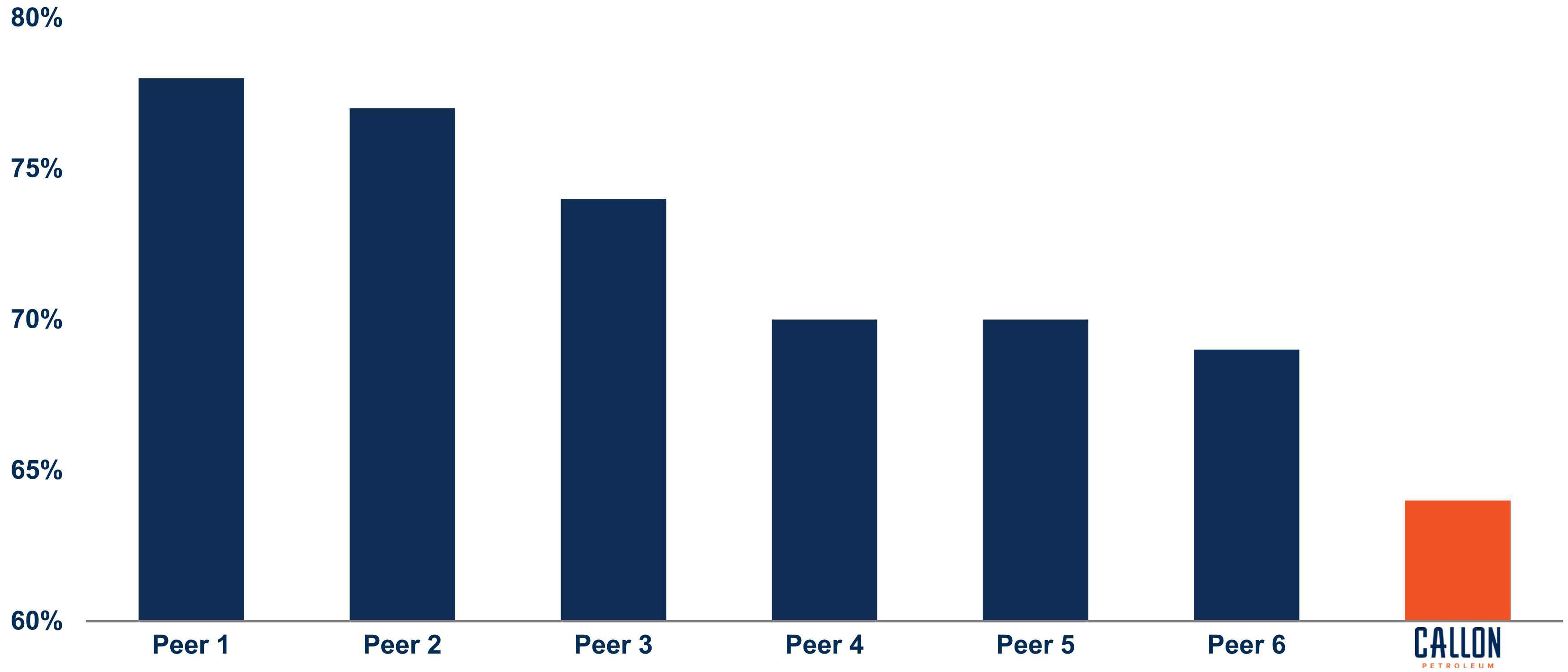
POTENTIAL PV-10 INCREASE FROM FULL FIELD DEVELOPMENT[3]

1. Change reflects 4Q22 over 4Q21
2. Reflects decrease from January 2022 to January 2023
3. Case study identifies the value gap between developing all 14 locations at once vs developing the wells in two separate projects over a period of 3 years. The case study assumes the child wells have approximately 30% degradation from initial wells and the loss of 14% of the locations due to increased spacing needed to limit wellbore communication

Lower Initial Decline Rates Support Sustainable FCF

FIRST YEAR DECLINE RATES[1]

DELAWARE BASIN



~10%

LOWER FIRST YEAR DECLINE RATES

1. Based on data from Enverus. Data set includes wells with 12 months of history placed online starting in January 2021. Peer list includes DVN, EOG, FANG, OXY, PDCE and PR

Deep Inventory of High-Quality Risked Locations

EAGLE FORD GROSS LOCATIONS IN CORE ZONES

	Total	Avg. Lateral
LOWER EF	115	6,259
TOTAL	**115**	**6,259**

DELAWARE BASIN GROSS LOCATIONS IN CORE ZONES

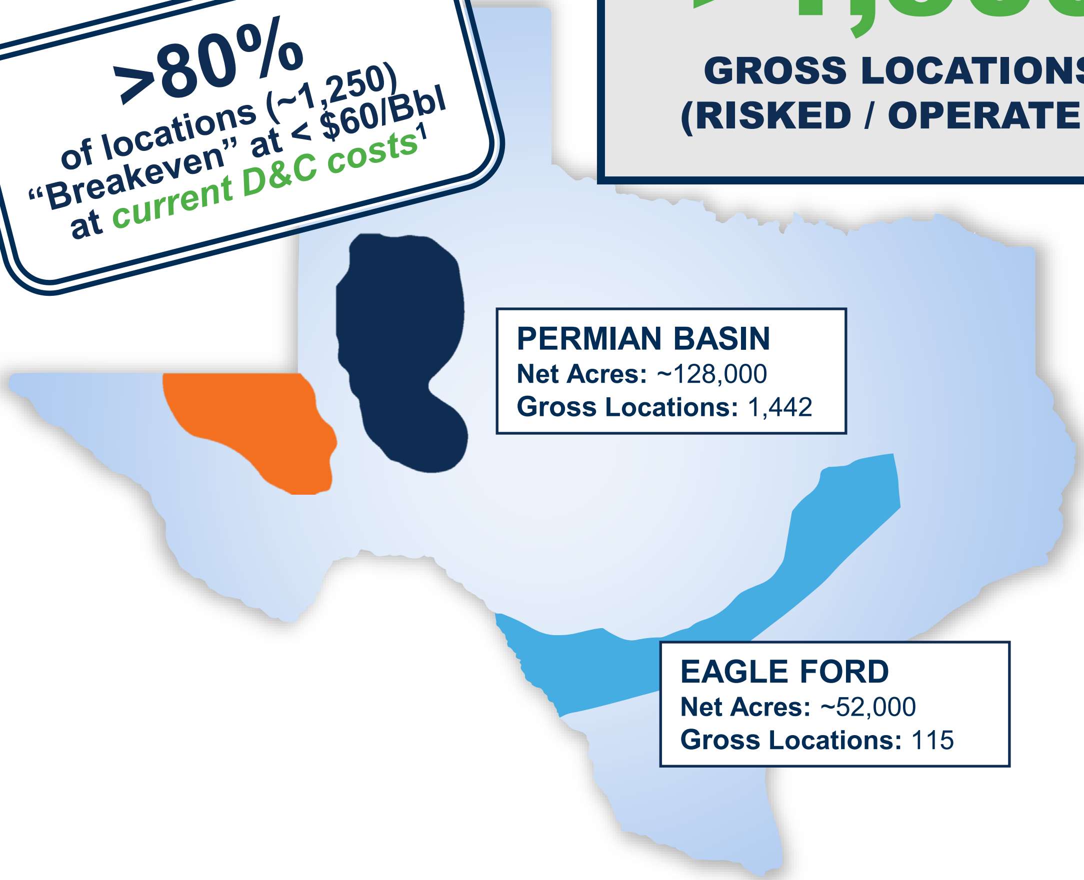
	Total	Avg. Lateral
BONE SPRING	189	9,365
WOLFCAMP A	451	8,235
WOLFCAMP B	238	8,549
WOLFCAMP C	99	8,838
TOTAL	**977**	**8,591**

MIDLAND BASIN GROSS 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**

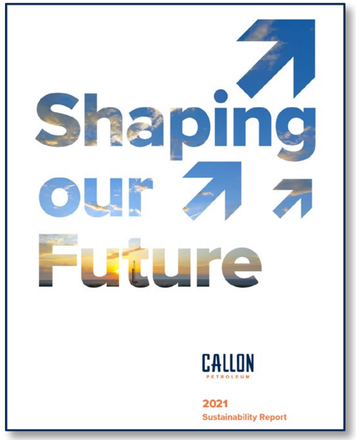
>80% of locations (~1,250) "Breakeven" at < $60/Bbl at current D&C costs[1]

>1,500
GROSS LOCATIONS (RISKED / OPERATED)



1. Assumes flat price deck of $60/Bbl, $30/Bbl of NGLs, and $3.00/MMBtu. "Breakeven" defined as PV-10 positive

Peer Leading Sustainability Goals

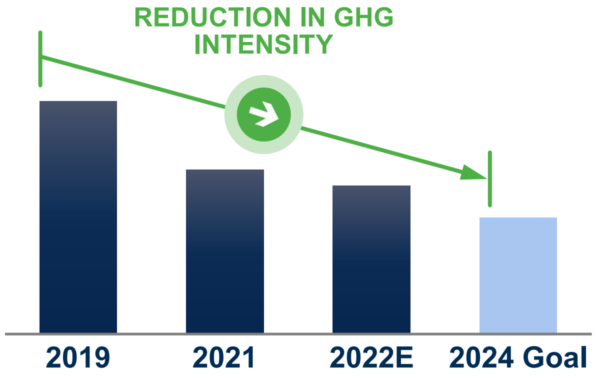


SUSTAINABILITY REPORT

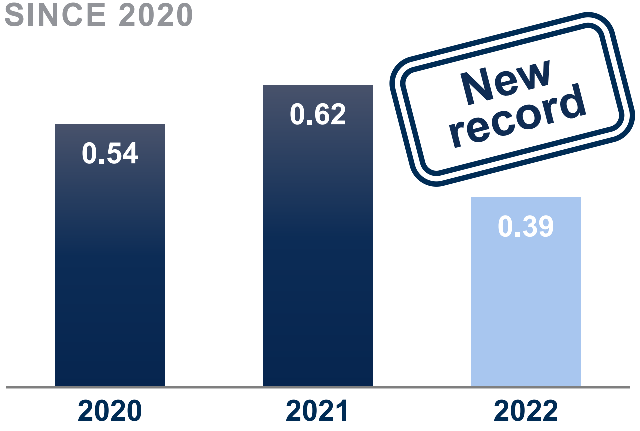
For more information, please refer to:

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

2023 Outlook

2023 GUIDANCE DETAILS

	1Q23	FY23
Total (MBoe/d)	**97 – 100**	**104 – 107**
Oil (MBbls/d)	59 – 61	63 – 65

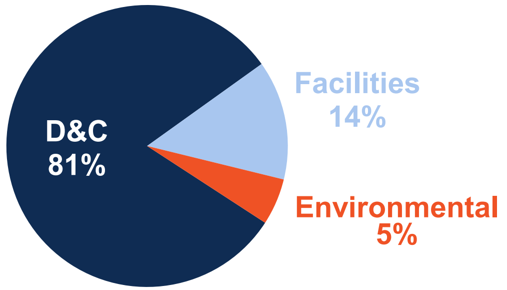
Lease Operating ($/Boe)		8.00 – 8.50
GP&T ($/Boe)		2.75 – 2.80
Prod & Ad Val Taxes (% of revs)		6.5% – 7.0%
Cash G&A ($MM)		105 – 115
Exploration Expense ($MM)		5 – 10

Effective Tax Rate		21% – 23%
Cash Taxes ($MM)		5 – 15

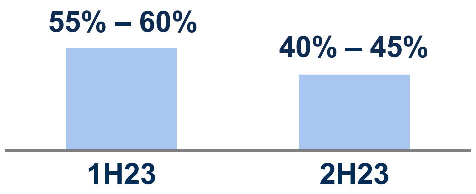
2023 CAPITAL EXPENDITURES

	1Q23	FY23
Capital Expenditures ($MM)[1]	290 – 300	1,000
TILs (wells)	15 – 17	115 – 120

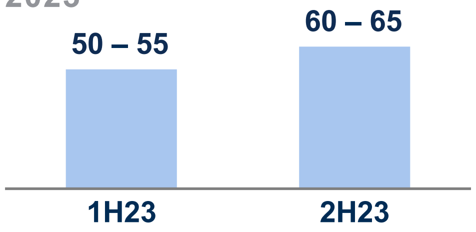
CAPITAL ALLOCATION
2023



CAPITAL EXPENDITURES
2023

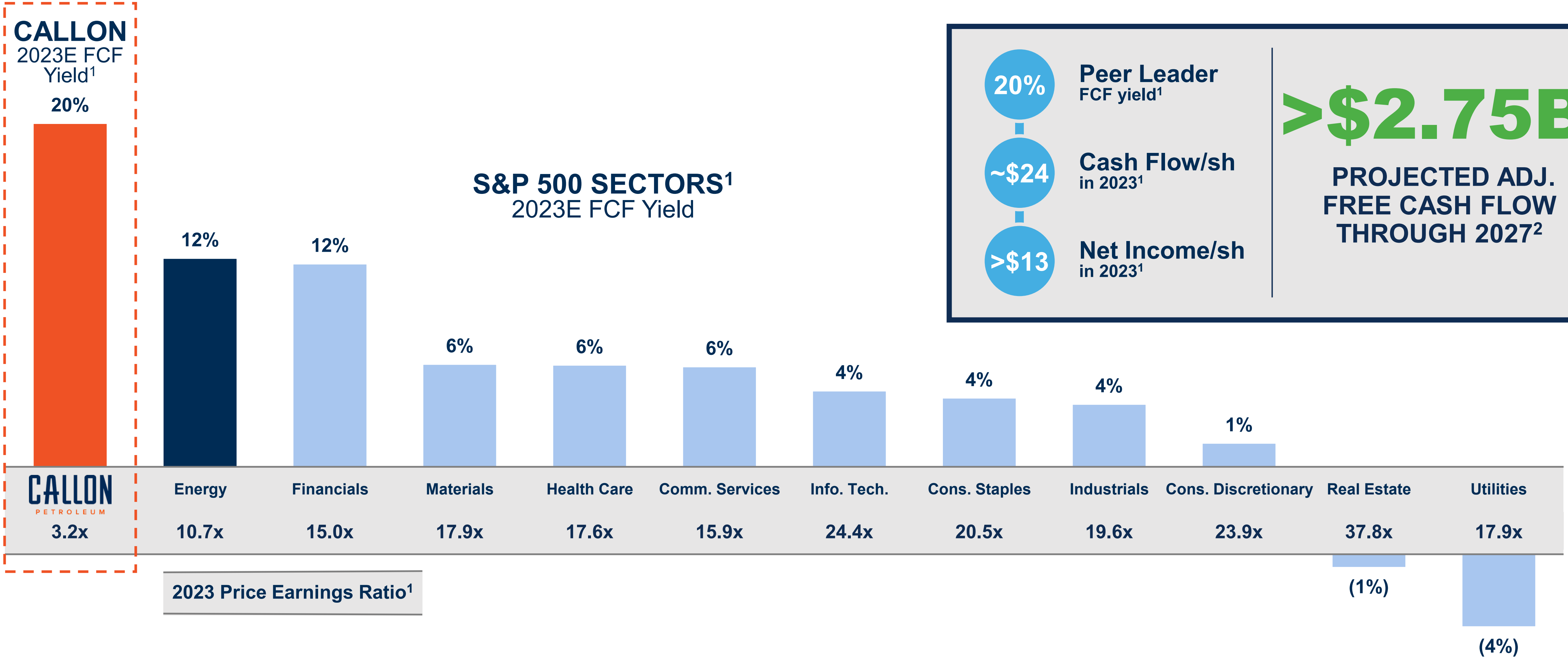


WELL TILs
2023



Note: With the change in accounting method from full cost to successful efforts, effective January 1, 2023, Callon will no longer capitalize G&A and interest. Please see slides 14 & 15 of Callon's 3Q22 earnings presentation for more information on the impact of the accounting change
1. Excludes land and seismic expenses

A Compelling Investment Opportunity



20% Peer Leader FCF yield[1]

~$24 Cash Flow/sh in 2023[1]

>$13 Net Income/sh in 2023[1]

>$2.75B PROJECTED ADJ. FREE CASH FLOW THROUGH 2027[2]

1. FactSet consensus 2023 estimates as of February 17, 2023
2. Assumes price deck of $80/Bbl and $3.50/MMBtu

Key Takeaways

PROVEN OPERATOR	"Life of Field" co-development model enhances long-term capital efficiency
HIGH-QUALITY INVENTORY	>1,500 risked locations in Texas' premier oil basins
CAPITAL ALLOCATION	Disciplined reinvestment in high return inventory complemented by debt reduction in near-term
SIGNIFICANT FREE CASH FLOW	Projected to generate >$2.75 billion in adj. FCF in 2023-27[1]; representing ~125% of equity market cap[2]
RAPID DEBT REDUCTION	Projected to reach key $2.0B debt target in 2H23

1. Assumes price deck of $80/Bbl and $3.50/MMBtu
2. Based on Callon's equity market capitalization as of February 17, 2023

APPENDIX

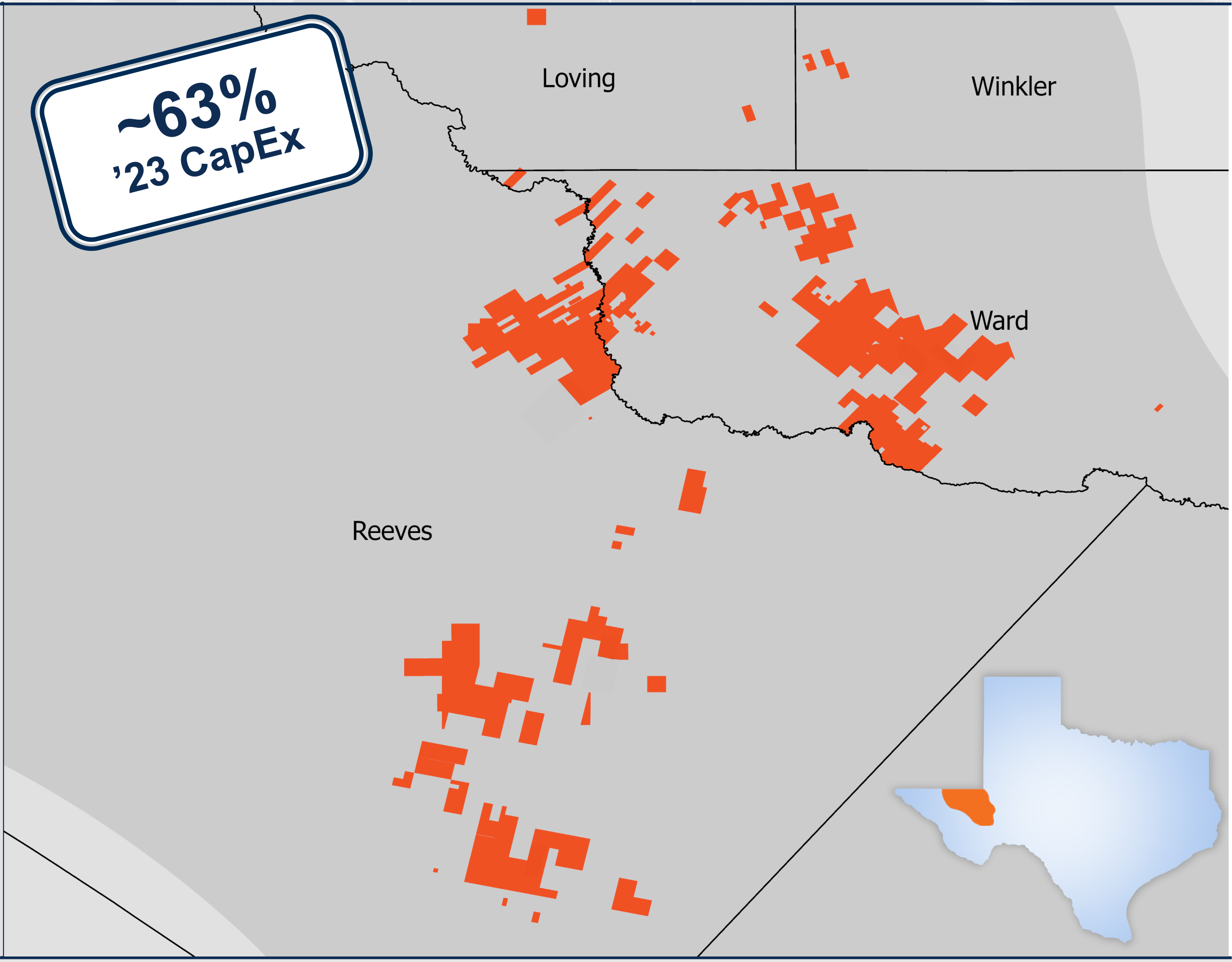
2023 Delaware Development Plan

- 3-4 rig program
- Gaining efficiencies through larger projects
  - Avg. size increases >65% to ~10 wells
  - Simultaneous D&C decreasing cycle times
- Target three primary formations
  - Wolfcamp A, B & C
- Organic inventory expansion
  - De-risking 3rd Bone Spring Shale and Lower Wolfcamp C

2023E

	Avg. Lat. Length	TILs	IRR[1]	Payout[1,2] (in yrs)
Delaware East	7,471	23	75%	1.3
Delaware South	9,342	13	57%	1.8
Delaware West	8,244	27	75%	1.3

1. Assumes price deck of $80/Bbl and $3.25/MMBtu
2. Time needed for the nominal undiscounted cash flow to return the initial DC&E capital expenditures



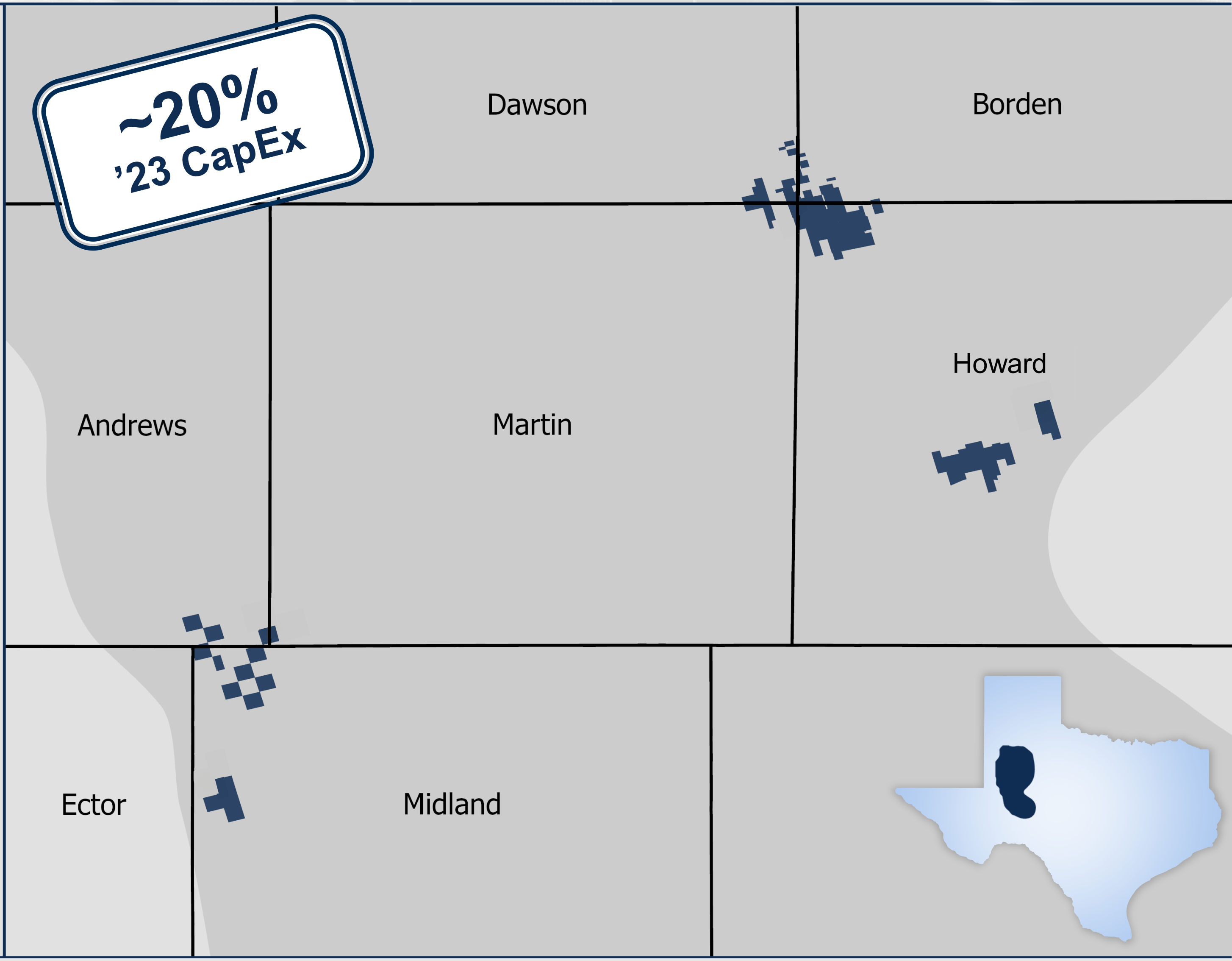
2023 Midland Development Plan

- 1-2 rig program
- Gaining efficiencies through larger projects
  - Avg. size increases >16% to ~9 wells
  - Simultaneous D&C decreasing cycle times
- Target three primary formations
  - Lower Spraberry & Wolfcamp A & B
- Organic inventory expansion
  - De-risking additional locations in the Middle Spraberry

2023E

	Avg. Lat. Length	TILs	IRR[1]	Payout[1,2] (in yrs)
Monarch	7,029	14	62%	1.6
Wildhorse	9,852	20	71%	1.4

1. Assumes price deck of $80/Bbl and $3.25/MMBtu
2. Time needed for the nominal undiscounted cash flow to return the initial DC&E capital expenditures

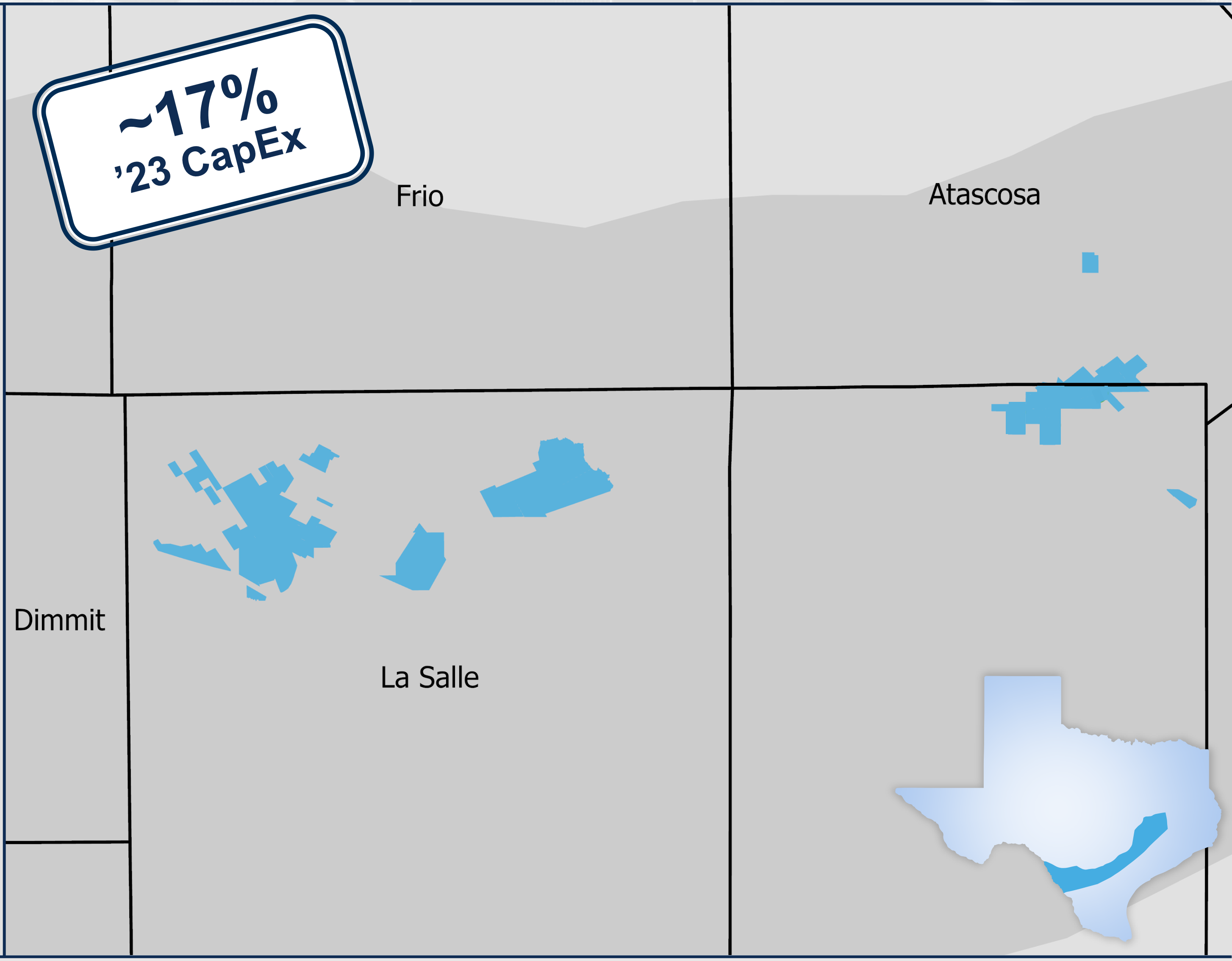


2023 Eagle Ford Development Plan

- ~1 rig program
- Avg. project size of ~6 wells
- Focused on Lower Eagle Ford
- Upside potential from ongoing Austin Chalk delineation

2023E

	Avg. Lat. Length	TILs	IRR[1]	Payout[1,2] (in yrs)
Eagle Ford	5.965	23	64%	1.6

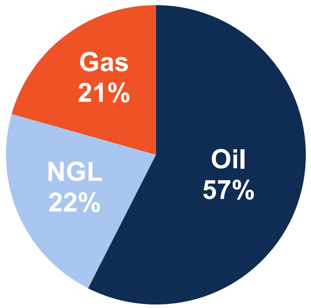


1. Assumes price deck of $80/Bbl and $3.25/MMBtu
2. Time needed for the nominal undiscounted cash flow to return the initial DC&E capital expenditures

Year-End 2022 Proved Reserves

PROVED RESERVES VALUE (PV-10)[1]	$10.5B
EXTENSIONS & DISCOVERIES[2]	68 MMBoe
PRODUCTION REPLACEMENT[3]	~180%
RESERVE LIFE INDEX[4]	~12.6 years

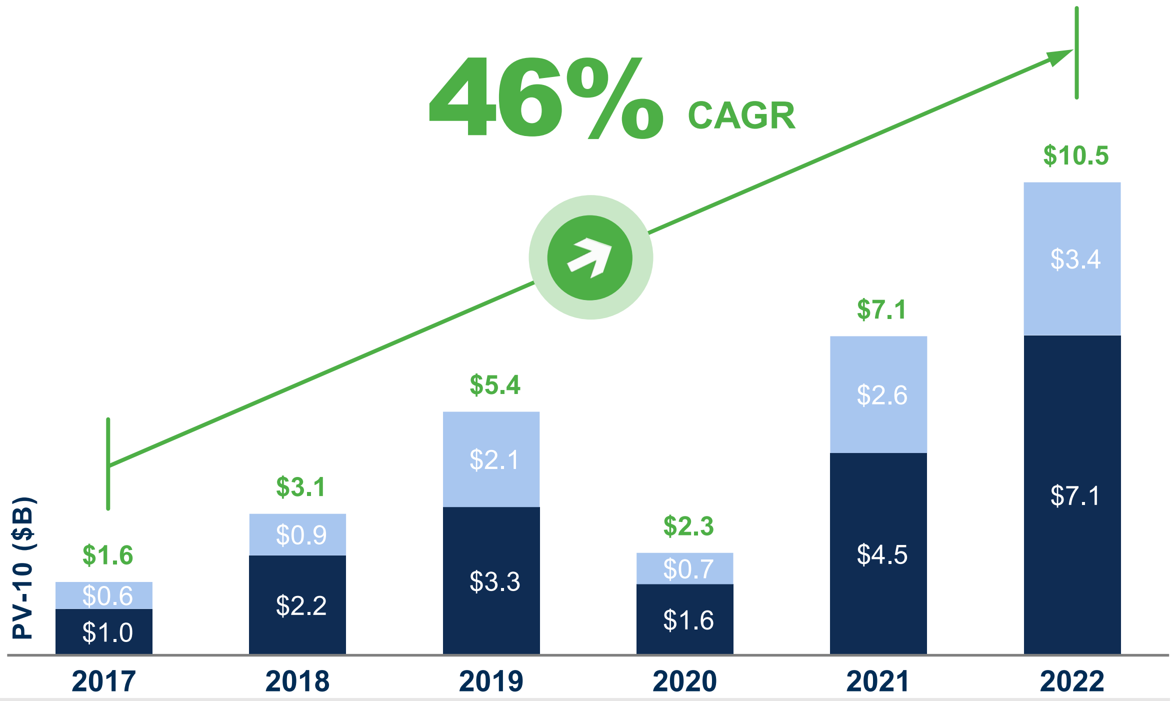
480 MMBoe



>$77/sh

IMPLIED PV-10 VALUE OF PROVED DEVELOPED RESERVES[5]

PV-10 VALUE OF PROVED RESERVES



	2017	2018	2019	2020	2021	2022
WTI Price[1]	$49.48	$58.40	$53.90	$37.44	$65.44	$95.02

TOTAL PV-10 (NON-GAAP) | PROVED DEVELOPED (PD) | PROVED UNDEVELOPED (PUD)

1. SEC trailing twelve-month oil price used to calculate the PV-10 at year-end
2. Year-end 2022 reserve adds defined as extension and discoveries
3. Production replacement is calculated by dividing reserve extensions and discoveries by annual production
4. Reserve life index is calculated by dividing total proved reserves by annual production
5. Based on proved developed PV-10 minus net debt of $2.3 billion as of December 31, 2022. The implied equity is then divided by 61.6 million shares outstanding as of February 17, 2023

Advantageous Debt Maturity Profile

Upgrades

FROM THREE CREDIT RATING AGENCIES IN 2022

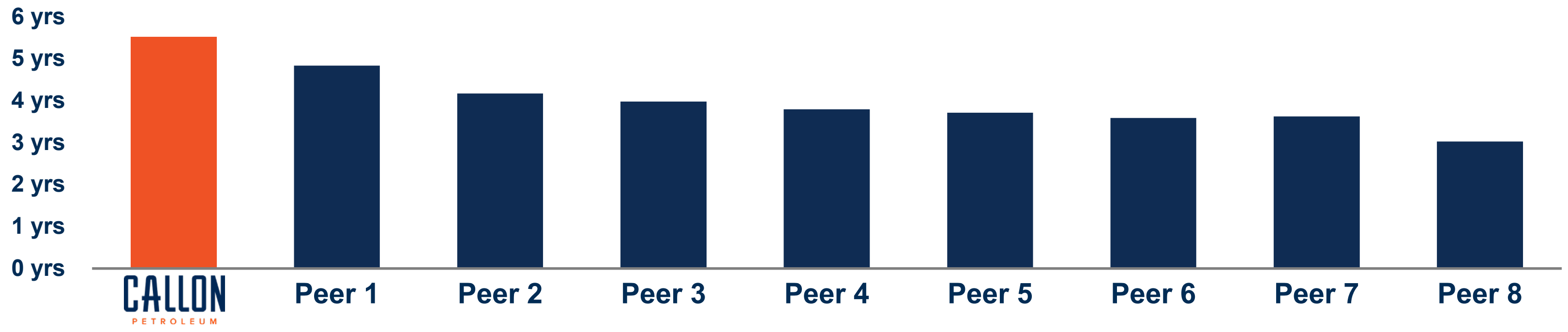
~$1B

LIQUIDITY[2] AT YEAR-END 2022

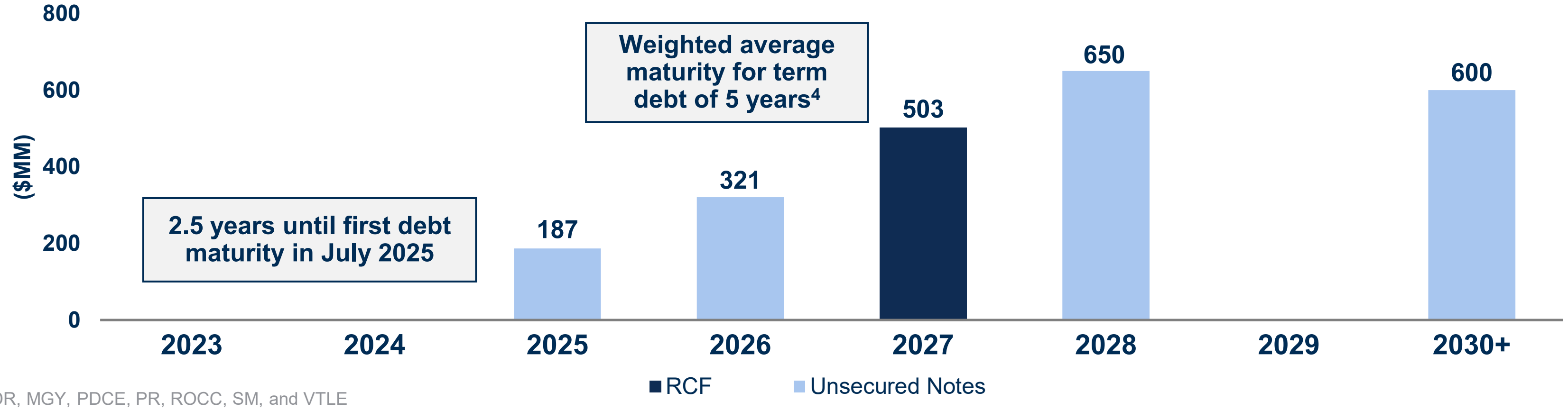
>3x

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

Peer[1] Leading Weighted Average Maturity Profile



Callon's Debt Maturity Profile



1. Weighted average maturity as of December 31, 2022, 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 December 31, 2022

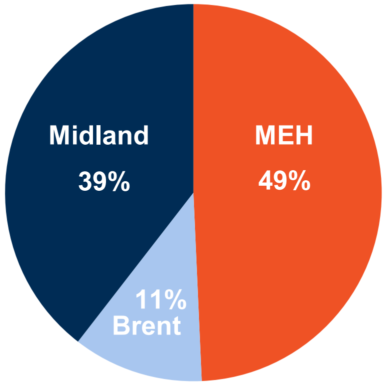
Increasing the Value Chain of Our Molecules

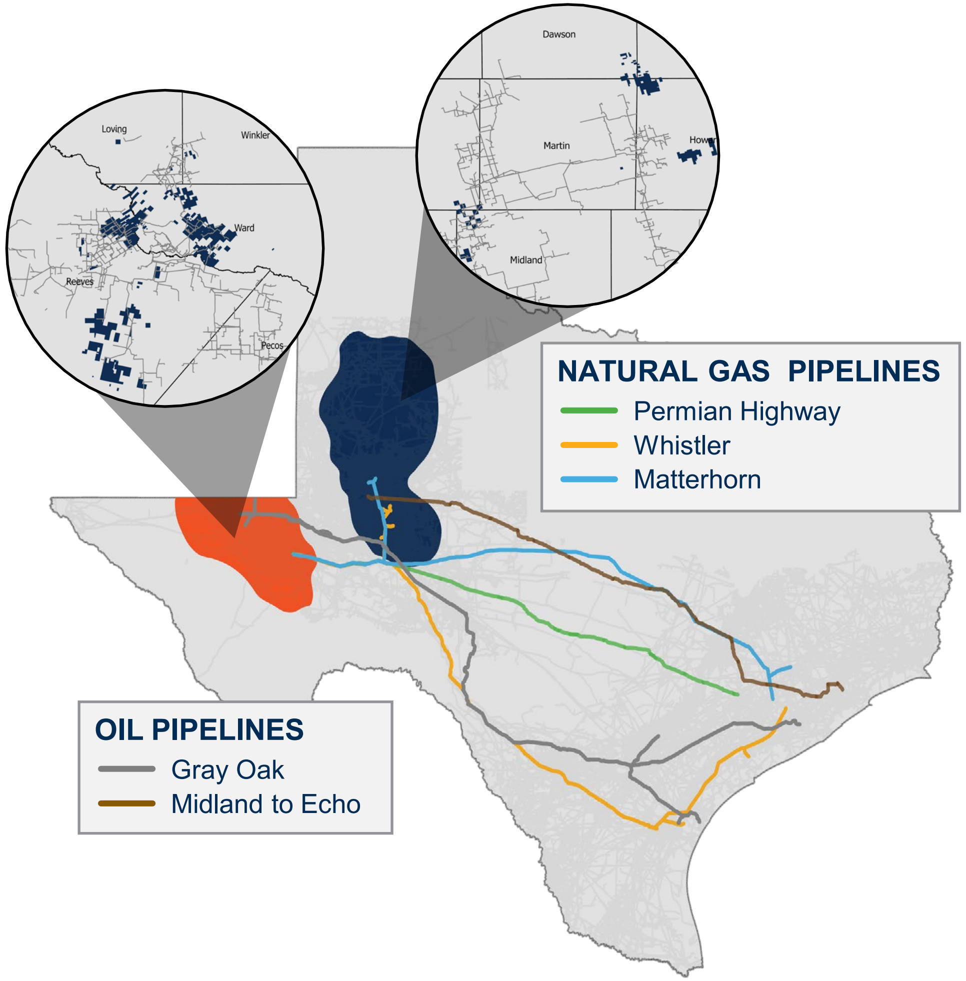
OIL

TAKEAWAY CAPACITY

- Portfolio approach employs a combination of in-basin sales and transportation arrangements to the Gulf Coast
- ~25,000 Bbls/d of transportation contracted on multiple long-haul pipelines to provide flow assurance and price diversification

PRICE EXPOSURE
2023-24[2]



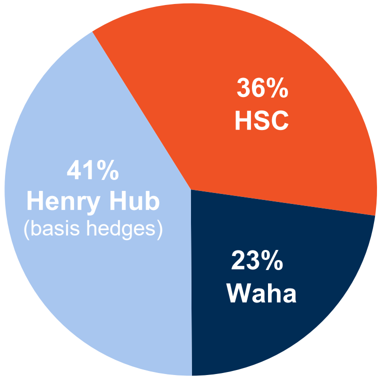


NATURAL GAS

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
2023-24[2]

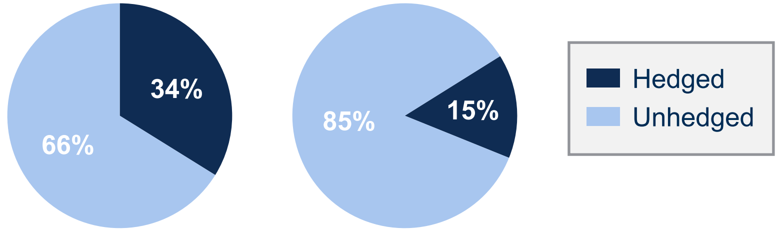


1. Dates assumed for long-haul transportation agreements are in-line with publicly available pipeline start up information as of February 8, 2023
2. Projections based on current hedge book and development plan as of February 14, 2023

Derivative Positions

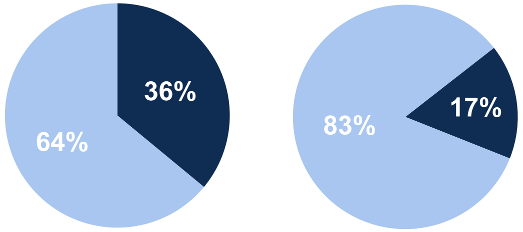
OIL VOLUMES

1H '23	2H '23



NATURAL GAS VOLUMES

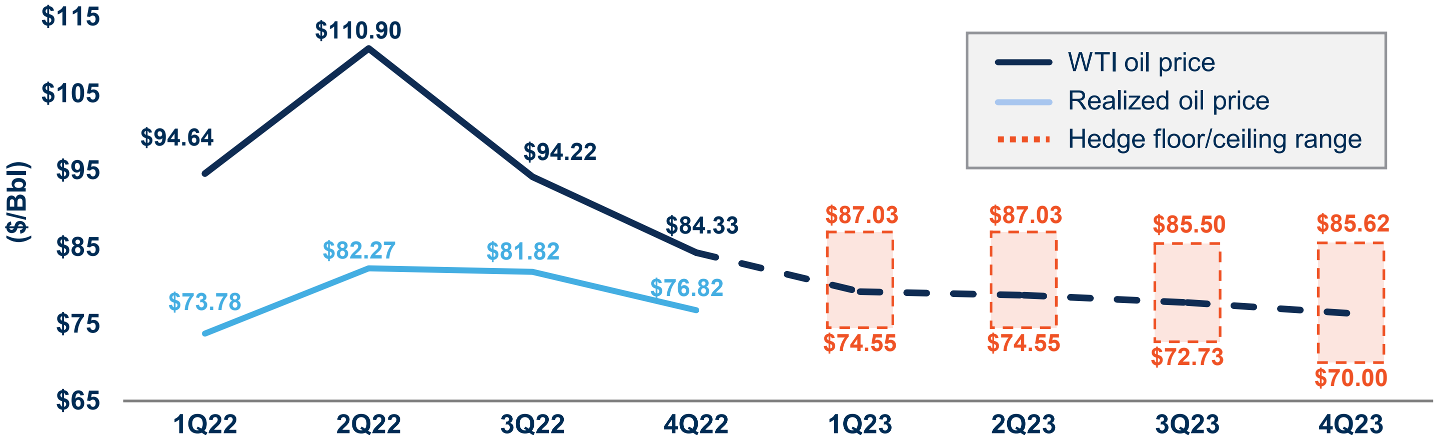
1H '23	2H '23



HEDGE GAINS / LOSSES BY QUARTER ($MM)

WTI Oil[1]	1Q23	2Q23	3Q23	4Q23
$70	$11	$13	$5	$1
$80	$5	$3	$4	$1
$90	($3)	($8)	($2)	($3)
NYMEX Gas[2]	**1Q23**	**2Q23**	**3Q23**	**4Q23**
$3.00	$6	$4	$5	$1
$3.50	$5	$3	$4	$1
$4.00	$3	$3	$3	$1

CALLON'S OIL PRICE REALIZATIONS[3]



2023 CASH FLOW SENSITIVITIES[1,2]

Annual Run Rate	Cash Flow from Operations
Oil: +/- $10	$199
Gas: +/- $0.50	$17

1. Assumes flat natural gas price of $3.50/MMBtu
2. Assumes flat oil price of $80/Bbl
3. Strip pricing as of February 16, 2023

Oil Hedges[1]

	1Q23	2Q23	3Q23	4Q23	FY 2023	FY 2024
NYMEX WTI (Bbls, $/Bbl)						
Swaps						
Total Volumes	675,000	682,500	184,000	-	1,541,500	-
Total Daily Volumes	7,500	7,500	2,000	-	4,223	-
Avg. Swap Price	$79.18	$79.18	$85.00	-	$79.87	-
Collars						
Total Volumes	810,000	819,000	368,000	368,000	2,365,000	-
Total Daily Volumes	9,000	9,000	4,000	4,000	6,479	-
Avg. Short Call Strike	$91.93	$91.93	$80.14	$80.14	$88.26	-
Avg. Long Put Strike	$73.22	$73.22	$70.00	$70.00	$72.22	-
Three-Way Collars						
Total Volumes	450,000	455,000	460,000	460,000	1,825,000	-
Total Daily Volumes	5,000	5,000	5,000	5,000	5,000	-
Avg. Short Call Strike	$90.00	$90.00	$90.00	$90.00	$90.00	-
Avg. Long Put Strike	$70.00	$70.00	$70.00	$70.00	$70.00	-
Avg. Short Put Strike	$50.00	$50.00	$50.00	$50.00	$50.00	-
Total WTI Volume Hedged (Bbls)	1,935,000	1,956,500	1,012,000	828,000	5,731,500	-
Average WTI Ceiling Strike ($/Bbl)	$87.03	$87.03	$85.50	$85.62	$86.56	-
Average WTI Floor Strike ($/Bbl)	$74.55	$74.55	$72.73	$70.00	$73.57	-
NYMEX WTI (Bbls, $/Bbl)						
Swaptions						
Total Volumes	-	-	-	-	-	1,830,000
Total Daily Volumes	-	-	-	-	-	5,000
Avg. Swap Price	-	-	-	-	-	$80.30

1. As of February 14, 2023

Gas Hedges[1]

	1Q23	2Q23	3Q23	4Q23	FY 2023	FY 2024
NYMEX HENRY HUB (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	-	910,000	920,000	310,000	2,140,000	-
Total Daily Volumes	-	10,000	10,000	3,370	5,863	-
Avg. Swap Price	-	$5.11	$5.11	$5.11	$5.11	-
Collars						
Total Volumes	4,500,000	1,820,000	1,840,000	620,000	8,780,000	-
Total Daily Volumes	50,000	20,000	20,000	6,739	24,055	-
Avg. Short Call Strike	$7.49	$5.50	$5.50	$5.50	$6.52	-
Avg. Long Put Strike	$4.95	$3.75	$3.75	$3.75	$4.37	-
Total NYMEX Volume Hedged (MMBtu)	4,500,000	2,730,000	2,760,000	930,000	10,920,000	-
Average NYMEX Ceiling Strike ($/MMBtu)	$7.49	$5.37	$5.37	$5.37	$6.24	-
Average NYMEX Floor Strike ($/MMBtu)	$4.95	$4.20	$4.20	$4.20	$4.51	-
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	2,390,000	2,730,000	2,760,000	1,540,000	9,420,000	3,660,000
Total Daily Volumes	26,556	30,000	30,000	16,739	25,808	10,000
Avg. Swap Price	($0.95)	($1.02)	($1.02)	($1.22)	($1.03)	($1.05)
HOUSTON SHIP CHANNEL DIFFERENTIAL (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	2,390,000	2,730,000	2,760,000	2,760,000	10,640,000	14,640,000
Total Daily Volumes	26,556	30,000	30,000	30,000	29,151	40,000
Avg. Swap Price	($0.29)	($0.29)	($0.29)	($0.29)	($0.29)	($0.42)

1. As of February 14, 2023

Non-GAAP Adjusted EBITDA[1]

($ thousands, except per Boe)	FY 2020	FY 2021	1Q 22	2Q 22	3Q 22	4Q 22	FY 2022
Net income (loss)	**($2,533,621)**	**$365,151**	**$39,737**	**$348,009**	**$549,603**	**$272,467**	**$1,209,816**
(Gain) loss on derivative contracts	27,773	522,300	358,300	81,648	(134,850)	25,855	330,953
Gain (loss) on commodity derivative settlements, net	95,856	(423,306)	(133,476)	(184,558)	(105,006)	(44,380)	(467,420)
Non-cash expense (benefit) related to share-based awards	2,663	12,923	4,166	(3,210)	99	1,452	2,507
Impairment of evaluated oil and gas properties	2,547,241	-	-	-	-	-	-
Merger, integration, transaction and other	43,107	21,944	(13)	1,051	2,861	(485)	3,414
Income tax (benefit) expense	122,054	180	484	3,009	3,515	4,785	11,793
Interest expense, net	94,329	102,012	21,558	20,691	19,468	17,950	79,667
Depreciation, depletion and amortization	480,631	356,556	102,979	109,409	122,833	131,296	466,517
Loss on extinguishment of debt	(170,370)	41,040	-	42,417	-	3,241	45,658
Adjusted EBITDA	**$709,663**	**$998,800**	**$393,735**	**$418,466**	**$458,523**	**$412,181**	**$1,682,905**
Primexx EBITDA[2]	-	$170,923	-	-	-	-	-
Total Production (MBoe)	37,193	34,894	9,239	9,162	9,873	9,779	38,053
Net Income per Boe	**($68.12)**	**$10.46**	**$4.30**	**$37.98**	**$55.67**	**$27.86**	**$31.79**
Adjusted EBITDA per Boe	**$19.08**	**$28.62**	**$42.62**	**$45.67**	**$46.44**	**$42.15**	**$44.23**

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 EBITDA, Adjusted Free Cash Flow and Adjusted Discretionary Cash Flow[1]

($ thousands)	FY 2021	1Q 22	2Q 22	3Q 22	4Q 22	FY 2022
Net cash provided by operating activities	**$974,143**	**$281,270**	**$372,325**	**$475,275**	**$372,647**	**$1,501,517**
Changes in working capital and other	(53,312)	123,805	25,096	(75,748)	6,786	79,939
Change in accrued hedge settlements	(28,208)	(31,951)	1,839	40,590	15,816	26,294
Cash interest expense, net	91,888	19,842	19,206	18,406	16,932	74,386
Merger, integration and transaction	14,289	769	–	–	–	769
Adjusted EBITDA	**$998,800**	**$393,735**	**$418,466**	**$458,523**	**$412,181**	**$1,682,905**
Less: Operational capital expenditures (accrual)	508,616	157,378	237,812	254,662	191,673	841,525
Less: Capitalized interest	89,738	23,506	24,416	25,964	27,187	101,073
Less: Interest expense, net of capitalized amounts	91,888	19,842	19,206	18,406	16,932	74,386
Less: Capitalized cash G&A	34,386	9,703	11,432	11,053	11,035	43,223
Adjusted Free Cash Flow	**$274,172**	**$183,306**	**$125,600**	**$148,438**	**$165,354**	**$622,698**

($ thousands)	1Q 22	2Q 22	3Q 22	4Q 22	FY 2022
Net cash provided by operating activities	**$281,270**	**$372,325**	**$475,275**	**$372,647**	**$1,501,517**
Changes in working capital	126,997	23,342	(76,994)	3,570	76,915
Merger, integration and transaction	769	–	–	–	769
Adjusted Discretionary Cash Flow	**$409,036**	**$395,667**	**$398,281**	**$376,217**	**$1,579,201**

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
Total debt	**$2,694**	**$2,623**	**$2,516**	**$2,373**	**$2,241**
Unamortized premiums, discount, and deferred loan costs, net	29	27	21	21	20
Adjusted total debt	**$2,723**	**$2,650**	**$2,537**	**$2,394**	**$2,261**
Less: Cash and cash equivalents	10	4	6	4	3
Net Debt	**$2,713**	**$2,646**	**$2,531**	**$2,390**	**$2,258**

($ millions)	2017	2018	2019	2020	2021	2022
Standardized measure of discounted future net cash flows	**$1,557**	**$2,941**	**$4,951**	**$2,310**	**$6,251**	**$9,004**
Add: present value of future income taxes discounted at 10% per annum	20	208	419	35	800	1,531
Total proved reserves - PV-10	**$1,577**	**$3,149**	**$5,370**	**$2,345**	**$7,051**	**$10,535**

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