CALLON
PETROLEUM

J.P. Morgan 2021 Energy, Power & Renewables Conference

June 23, 2021

IMPORTANT DISCLOSURES – EARNINGS DECK

FORWARD LOOKING STATEMENTS

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; future levels of development activity and associated production, capital expenditure, expense, and cash flow returns, and earnings expectations; the Company's 2021 production, expense and capital expenditure guidance; estimated inventory and reserve quantities and the present value thereof; 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 the COVID-19 pandemic and various governmental actions taken to mitigate its impact or actions by, or disputes among, members of OPEC and other oil and natural gas producing countries, such as Russia, with respect to production levels or other matters related to the price of oil; 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 activities; and other risks more fully discussed in our filings with the SEC, including our most recent Annual Reports 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.

SUPPLEMENTAL NON-GAAP FINANCIAL MEASURES

This presentation includes non-GAAP financial measures such as "Adjusted Free Cash Flow," "Adjusted G&A," "Full Cash G&A Costs," and "Adjusted EBITDA". 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. Please see the appendix for reconciliations to the nearest GAAP measures.

Adjusted free cash flow is a supplemental non-GAAP measure that is defined by the Company as adjusted EBITDA less operational capital, cash capitalized interest, net cash interest expense and capitalized cash G&A (which excludes capitalized expense related to share-based awards). We believe adjusted free cash flow 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).

Adjusted G&A is a supplemental non-GAAP financial measure that excludes certain non-cash incentive share-based compensation valuation adjustments. Callon believes that the non-GAAP measure of adjusted G&A is useful to investors because it provides a meaningful measure of our recurring G&A expense and provides for greater comparability period-over-period.

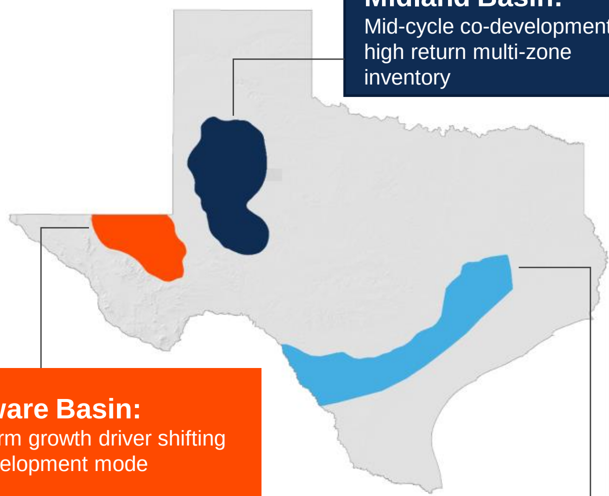
Full cash G&A is a supplemental non-GAAP financial measure that Callon defines as adjusted G&A – cash component plus capitalized G&A excluding capitalized expense related to share-based awards. Callon believes that the non-GAAP measure of full cash G&A is useful because it provides users with a meaningful measure of our total recurring cash G&A costs, whether expensed or capitalized, and provides for greater comparability on a period-over-period basis.

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 stock-based compensation expense, merger and integration expense, (gain) loss on extinguishment of debt, and other operating 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 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 above may not be comparable to similarly titled measures of other companies.

A DIFFERENTIATED VALUE PROPOSITION

COMPLIMENTARY ASSET PORTFOLIO

Midland Basin:
Mid-cycle co-development of high return multi-zone inventory



Delaware Basin:
Long-term growth driver shifting into development mode

Eagle Ford Shale:
Highly efficient cash flow machine with repeatable, low-risk inventory

KEY STATISTICS

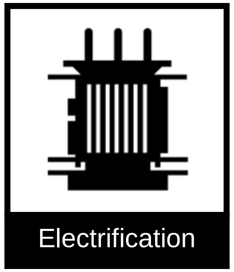
Total Net Acres	**~180,000**
1Q21 Total Production (Mboe/d)	**81.0**
1Q21 Oil Production (MBbl/d)	**52.0**
Market Cap[4] ($BN)	**$2.4**
Enterprise Value[4] ($BN)	**$5.3**

- Premier asset portfolio for *sustained* free cash flow generation
  - Over 1,100 risked locations with breakeven pricing at $40/Bbl (WTI) and below
  - Diversification from Permian and Eagle Ford positions provides balanced corporate cash conversion cycles
  - “Life of field” development philosophy preserves inventory economics and underpins net asset value
  - Moderated reinvestment rates[1] and resultant production growth
- Clear path to shareholder value creation from reduction of absolute debt levels
  - Transfer of enterprise value composition from debt to equity
  - Industry leading cash margins accelerate pace of deleveraging
  - Between $500-$800 million[2] in estimated adjusted FCF[3] at $50-$60/Bbl WTI
  - Current forecast of over $200 million in FY21 at strip pricing[4]
- Tangible financial goals provide clarity for priorities
  - Target Net Debt to Adjusted EBITDA[3] < 2.5x by year end 2022
  - Medium-term target Net Debt to Adjusted EBITDA[3] < 2.0x from FCF[3] and asset monetizations
- Continuous improvement culture around ESG
  - 2020 a record year for safety and spill management
  - Investing to actively reduce flaring and lower overall emissions
  - Increasing compensation alignment with sustainability related corporate goals
  - Targeting 40%-50% reduction in GHG Emissions Intensity by 2025[5]

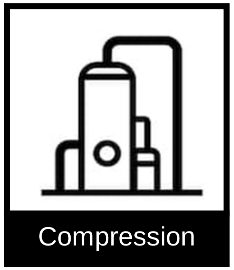
1. Callon defines “reinvestment rate” as (Accrued Operational Capital Expenditures) / (Adjusted Discretionary Cash Flow - Capitalized Expenses).
2. Estimated value for combined FCF generation from 2021-2023 using a reinvestment rate assumption of 65% - 75%.
3. Adjusted EBITDA and adjusted FCF are non-GAAP measures. Please see the appendix for reconciliations to the nearest GAAP measures.
4. As of 6/6/2021.
5. Versus 2019 levels.

PATH TO DECARBONIZATION

2021 INITIATIVES

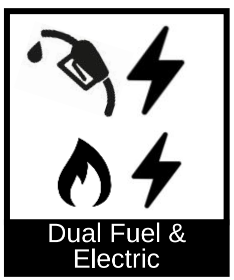


Expand field electrification to eliminate diesel generators



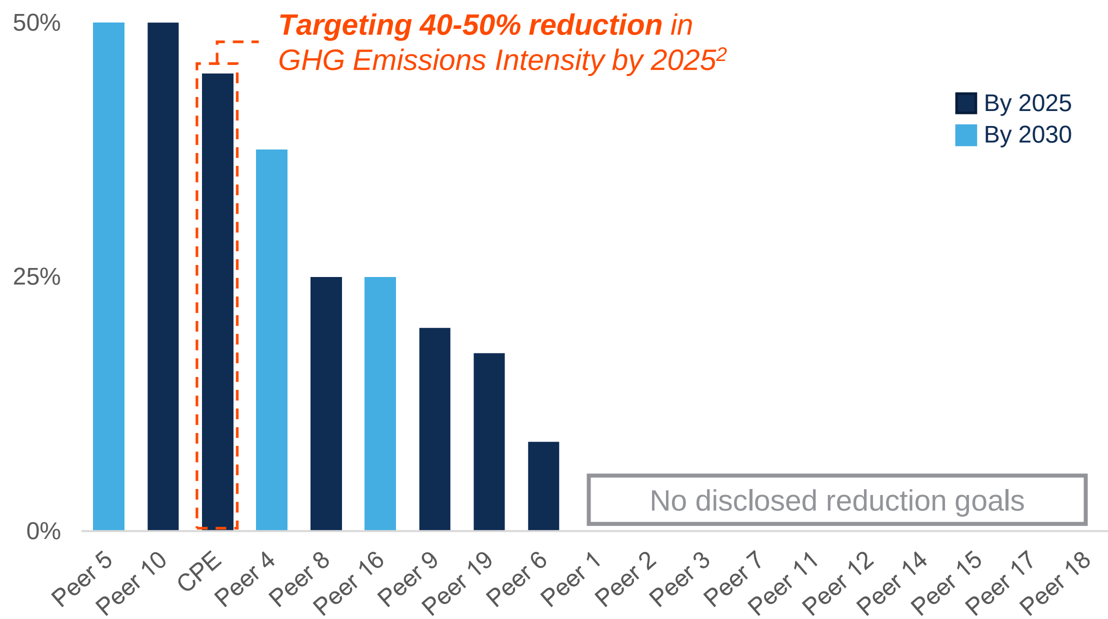
Field compression optimization projects

Expanding gas gathering optionality to mitigate 3rd party flaring risk



Utilizing dual fuel and tested first electric frac fleet

GREENHOUSE GAS (GHG) INTENSITY REDUCTION TARGETS[1]



ROUTINE FLARED GAS REDUCTION TARGETS[1]

100% Elimination

By 2025	By 2030
CPE	DVN
CDEV	HESS
COP	OXY
EOG	PXD
FANG	XOM
LPI	

No Flaring Target Disclosed

APA	MTDR
CLR	OVV
MRO	PDCE
	PVA
	SM
	XEC

1. Data as of 6/21/21 from company presentations. Peers include: APA, CDEV, CLR, COP, DVN, EOG, FANG, HES, LPI, MRO, MTDR, OVV, OXY, PDCE, PVA, PXD, SM, XEC, AND XOM.
2. Versus 2019 pro forma.

EVOLVING EXECUTIVE COMPENSATION FOR 2021

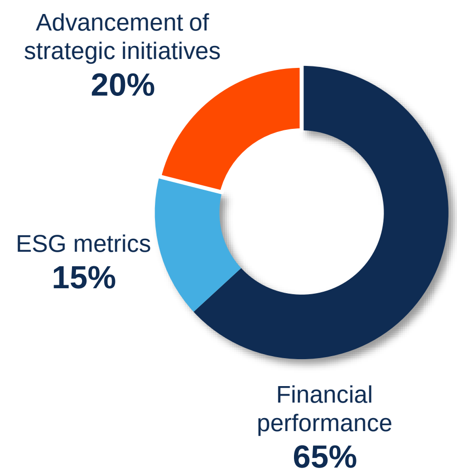
ANNUAL BONUS ALIGNED WITH SHAREHOLDER PRIORITIES

Prioritizing financial performance and ESG initiatives

- Returns
- ESG Performance
- Reduced Leverage
- Corporate Cash Margins
- Relative Total Shareholder Returns

Payout capped at target if absolute TSR is negative for the year

REDESIGNED ANNUAL INCENTIVE FRAMEWORK - 2021



80% Quantitative Metrics

Financial

- Leverage
- CROCI
- Corporate cash margins
- Relative Total Shareholder Returns[1]

ESG

- Flaring metrics
- Total Recordable Incident Rate (TRIR)
- Fluid Spills

PROACTIVE COMPENSATION MANAGEMENT

↓ 17.5%	CEO Target Long Term Incentive
↓ 12.5%	CEO Total Target Compensation
↓ >10%	Executive Officer Target Long Term Incentive
↓ 12.5%	Director Compensation

LONG TERM INCENTIVE PLAN UPDATES

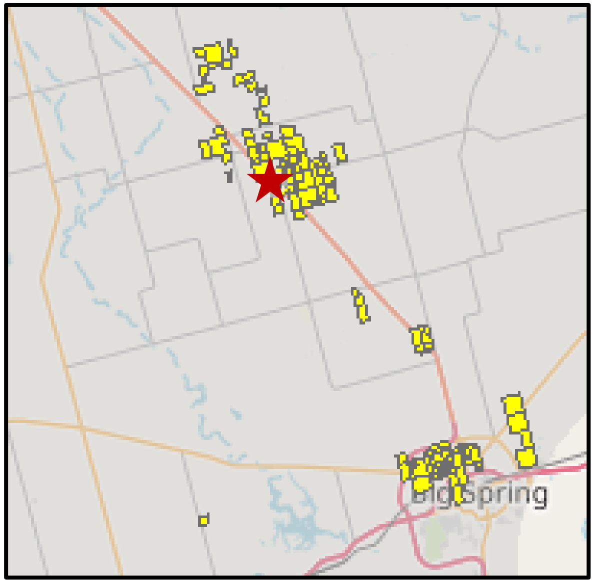
- Introduction of new cash performance units (“CPUs”) with 60% weighting
- Payout value to be determined by adjusted free cash flow and average annual return on capital employed (“ROCE”) over three-year performance period
- Alignment with Callon strategic initiatives
  - Achieving sustainable free cash flow generation
  - Competitive returns within and outside energy industry

1. Annual incentives capped at a maximum of 100% of Target payout if absolute TSR for the year is negative.

SUCCESSFUL TEST OF E-FRAC TECHNOLOGY[1]

INITIAL E-FRAC PROJECT OVERVIEW

- Chapparal Unit (Howard County)
  - Three-well pad targeting Lower Spraberry, WCA, and WCB
  - 160 total stages completed
  - More than 56 million pounds of proppant delivered over ~34,000 lateral feet
  - Average number of stages per day[2] : 9



- Critical project elements and key learnings
  - "Rich" field gas management and entrained liquids handling
  - Piping and compression management hurdles and opportunities
  - Evaluation of grid power options and full cycle investment cost for future development

1. Photo courtesy of USWS who performed the completion work for Callon on the Chapparal pad in Howard County within the Midland Basin,
2. Excludes the initial setup, compression, and safety days to ramp activity,

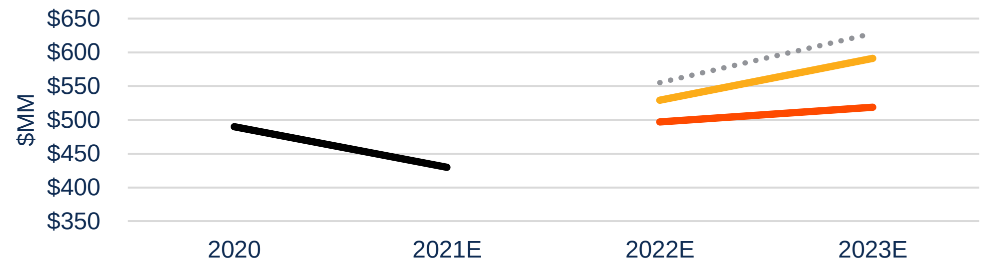
STRONG ADJUSTED FCF FOR ABSOLUTE DEBT REDUCTION

Planning Period	Price Assumption	Reinvestment Rate[1]
2022E / 2023E	$50/Bbl	75%
	$55/Bbl	70%
	$60/Bbl	65%

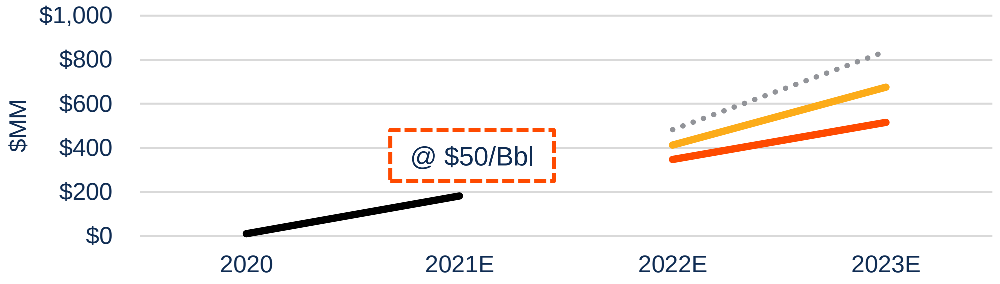
HIGHLIGHTS

- FY 2021 Plan
  - $430 MM Operational Capex (12% YoY Reduction)
  - Implied 75% Reinvestment Rate[1] at $50/Bbl
  - Sustains production and increases FCF for debt repayment @ $50/Bbl, while positioning for medium-term activity
- 2022 and 2023 scenarios at or below 75% reinvestment rates provide acceleration of FCF generation and associated deleveraging
- $500 MM to $800 MM of cumulative adjusted FCF over next three years (2021E @ $50/Bbl)
- Production CAGRs of 1% - 4% over FY 2021 (approximates FY 2020 volumes by 2023 at top end of range)

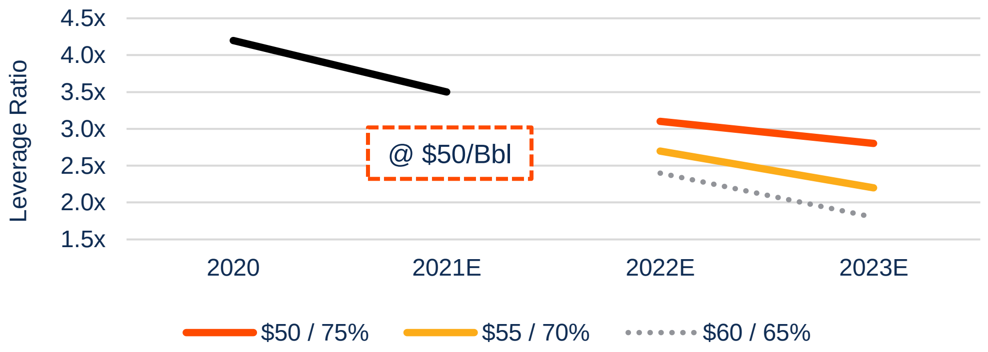
OPERATIONAL CAPITAL EXPENDITURES



CUMULATIVE ADJUSTED FREE CASH FLOW



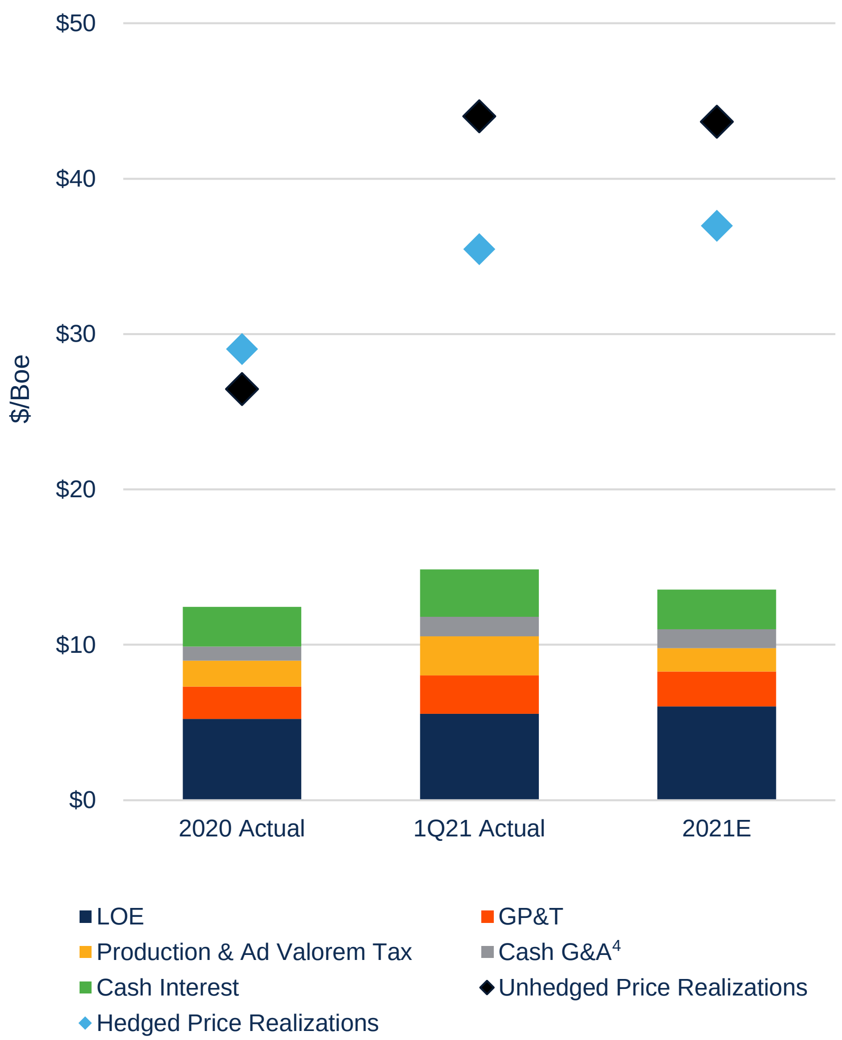
NET DEBT / ADJUSTED EBITDA[2]



1. Callon defines “reinvestment rate” as (Accrued Operational Capital Expenditures) / (Adjusted Discretionary Cash Flow - Capitalized Expenses).
2. No assumed proceeds from asset monetizations included.

MANAGING CASH COSTS FOR IMPROVED MARGINS

"ALL-IN" CASH COSTS[1] VS REALIZATIONS[2]



1Q21 Results	Permian	Eagle Ford
Daily production (MBoe/d)	57.8	23.2
% Oil	59%	76%
% NGL	21%	11%
Realized price[3] ($/Boe)	$42.06	$48.85
Production Costs:		
LOE ($/Boe)	$4.31	$8.65
Production and ad valorem taxes ($/Boe)	$2.32	$3.07
GP&T ($/Boe)	$2.54	$2.29
Operating margin ($/Boe)	**$32.89**	**$34.84**

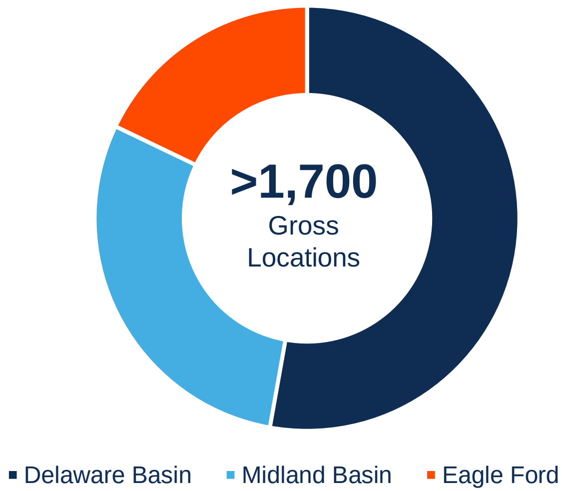
Comparable operating cost structures with diversification across commodity mix and physical pricing points contribute to strong corporate margins

1. "All-in" Cash Costs include LOE, GP&T, Cash G&A, Cash Interest Expense, and Production and Ad Valorem Taxes.
2. Price realizations for 2020 and 1Q21 are unhedged and hedged price per Boe per our earnings release. Price realizations for 2021E assumes midpoint of cost guidance and consensus benchmark prices of $58.67 WTI and $2.70 Henry Hub as of May 3, 2021, accounting for Company differential assumptions and current hedges.
3. Prices are exclusive of hedging.
4. Cash G&A is a non-GAAP measure. Please see the appendix for reconciliations to the nearest GAAP measures.

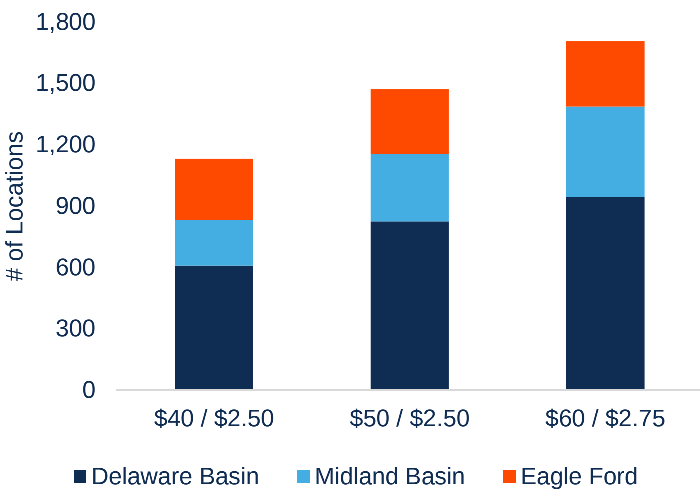
ROBUST PORTFOLIO FOR SCALED DEVELOPMENT

PRIMARY ZONE INVENTORY OVERVIEW

INVENTORY BY AREA



ECONOMICS[1]



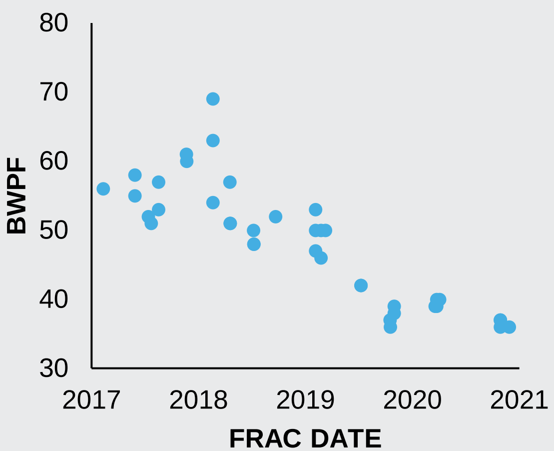
DEVELOPMENT STRATEGY

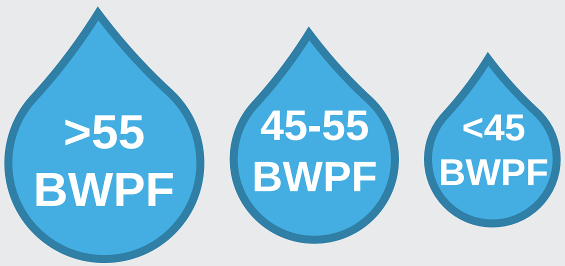
- "Primary zone" inventory limited to delineated zones in active development
- Over 1,100 risked locations with breakeven economics at $40/Bbl or lower
  - All type curve economics risked for development interference learnings from scaled project deployment
  - Engineered spacing on a pad-by-pad basis
- Delaware Basin
  - Primary zones: 2BS / 3BS / WCA / WCB / WCC
  - Average lateral: ~8,700' Average W.I.: ~83%
  - Up to six wells per zone, with tailored spacing for offset wells
  - Other potential zones: Canyon Sands / Avalon
- Midland Basin
  - Primary zones: MS / LS / WCA / WCB
  - Average lateral: ~7,000' Average W.I.: ~87%
  - Six to eight wells per zone, with custom spacing for offset wells
  - Other potential zones: Clearfork / Jo Mill / Penn Shale / Atoka
- Eagle Ford
  - Primary zone: Lower Eagle Ford
  - Average lateral: ~7,200' Average W.I.: ~90%
  - Average lateral spacing of ~525'
  - Other potential zones: Austin Chalk
  - Enhanced oil recovery being evaluated

1. Number of gross locations with breakeven PV10 economics at or below assumed NYMEX benchmark oil and natural gas flat price scenarios.

OPTIMIZING INVENTORY VALUE[1]

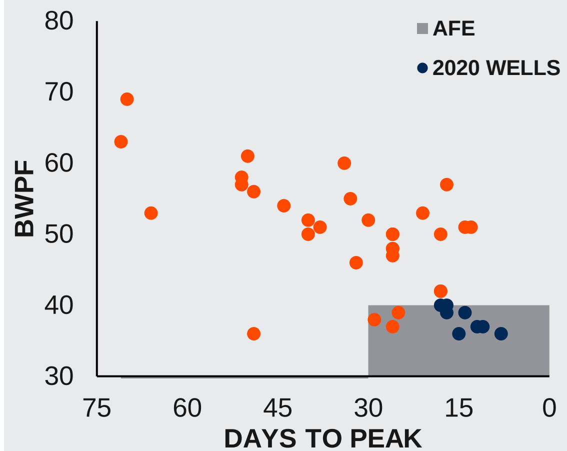
COMPLETION EVOLUTION

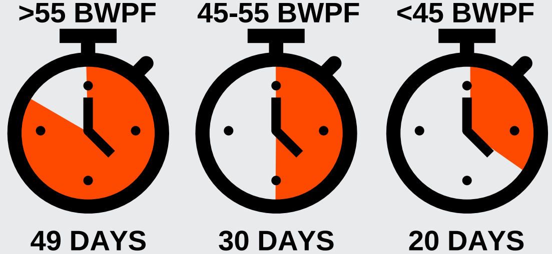




~$350,000 CWC SAVINGS

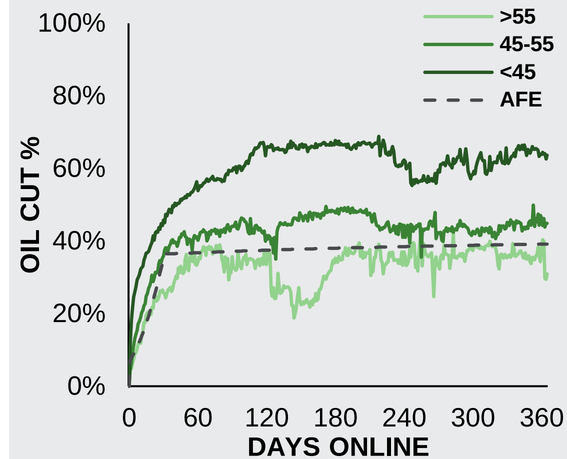
ACCELERATED OIL PEAK

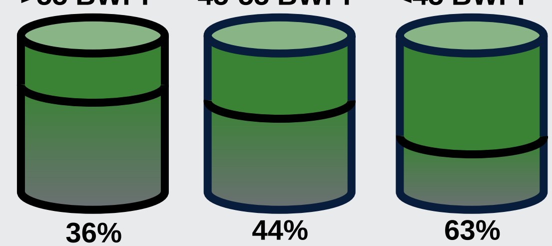




10-DAY ACCELERATION

INCREASED OIL CUT





24% OIL CUT INCREASE

Reduced WCA fluid loading results in an incremental 10% in single-well NPV from reduced well cost, accelerated oil peak, and increased oil cut

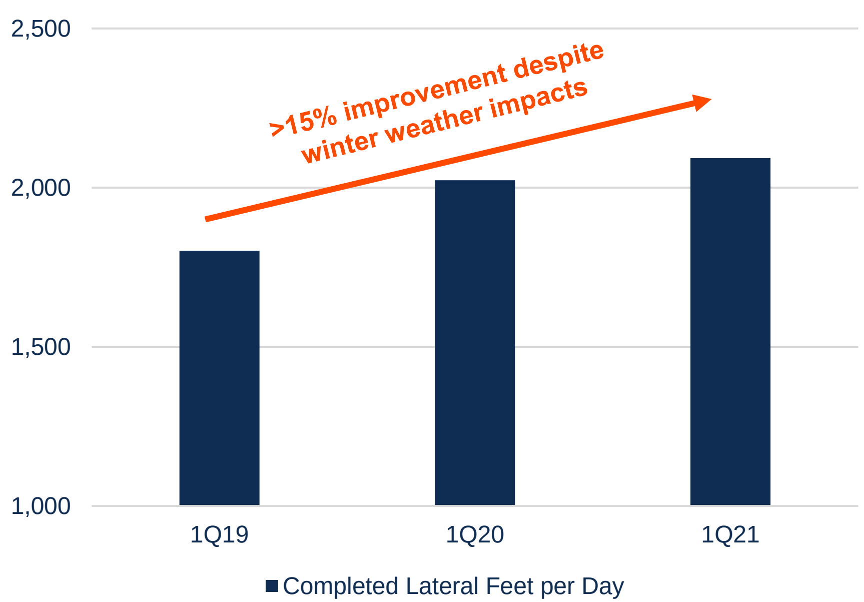
1. Midland Basin example.

DRILLING AND COMPLETIONS CONTINUE TO IMPROVE

LOWERING COSTS FOR FULL FIELD DEVELOPMENT

- Continued application of combined learnings driving consistent well results at low cost
- First quarter average DC&E cost of ~$500 per lateral foot across all asset areas
- Recently set a new company record for Delaware lateral efficiency drilling 11,359' in just 75 hours

EAGLE FORD COMPLETION EFFICIENCY ADVANCES

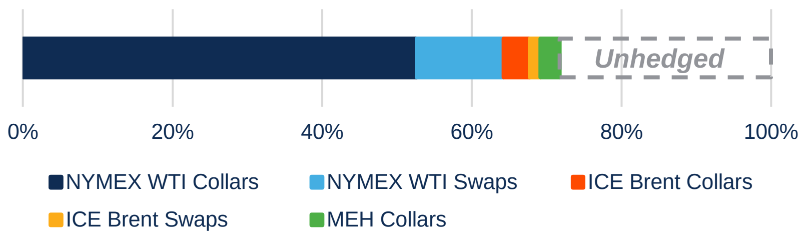


DRILLING PRODUCTIVITY DRIVES SAVINGS[1]

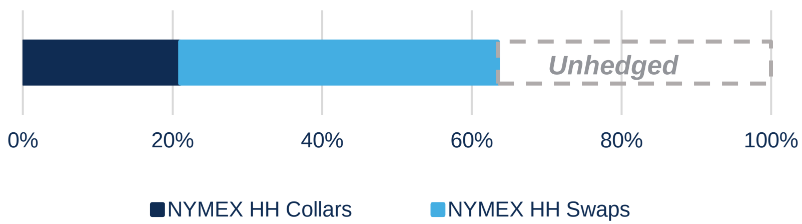
1. Drilling cost per lateral foot represent FY21 drilling activity YTD. Percentage savings are calculated as the improvement in effective cost per lateral foot for YTD FY21 versus 2020.

CASH FLOW PROTECTION WITH UPSIDE PARTICIPATION

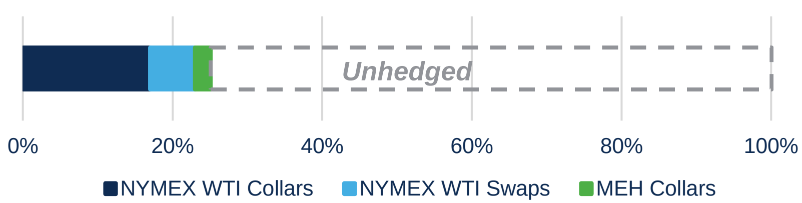
2Q-4Q FY21 Oil Hedges[1]



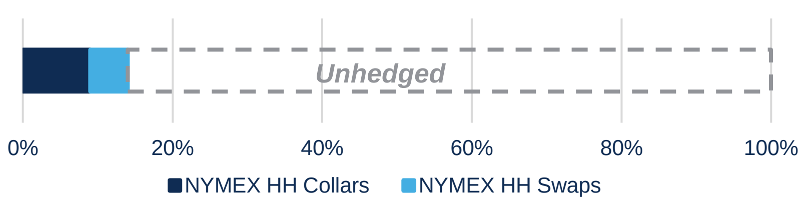
2Q-4Q FY21 Natural Gas Hedges[1]



2022 Oil Hedges[1,2]



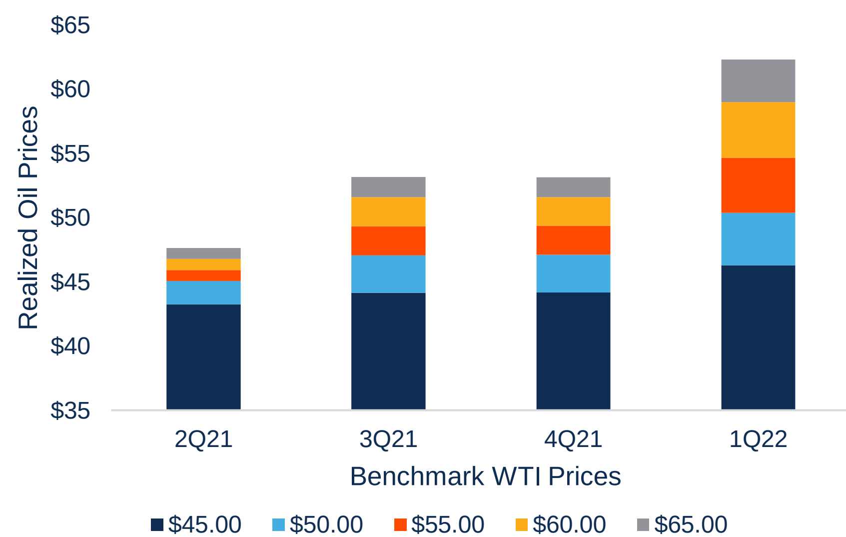
2022 Natural Gas Hedges[2]



2021 PROTECTED WITH 2022 UPSIDE POTENTIAL

- 2Q-4Q FY21 oil production ~70% hedged
  - ~60% hedged in 2H21
- Ongoing optimization has increased exposure to higher oil prices across physical pricing points
- 2Q21-4Q21 natural gas ~63% hedged
- 2022 oil production ~25% hedged[2]
  - -~19% of production hedged with collars at $52.5 / $64.7
  - -~6% of production hedged with WTI swaps at $60
  - Cash flow protection to support debt reduction goals

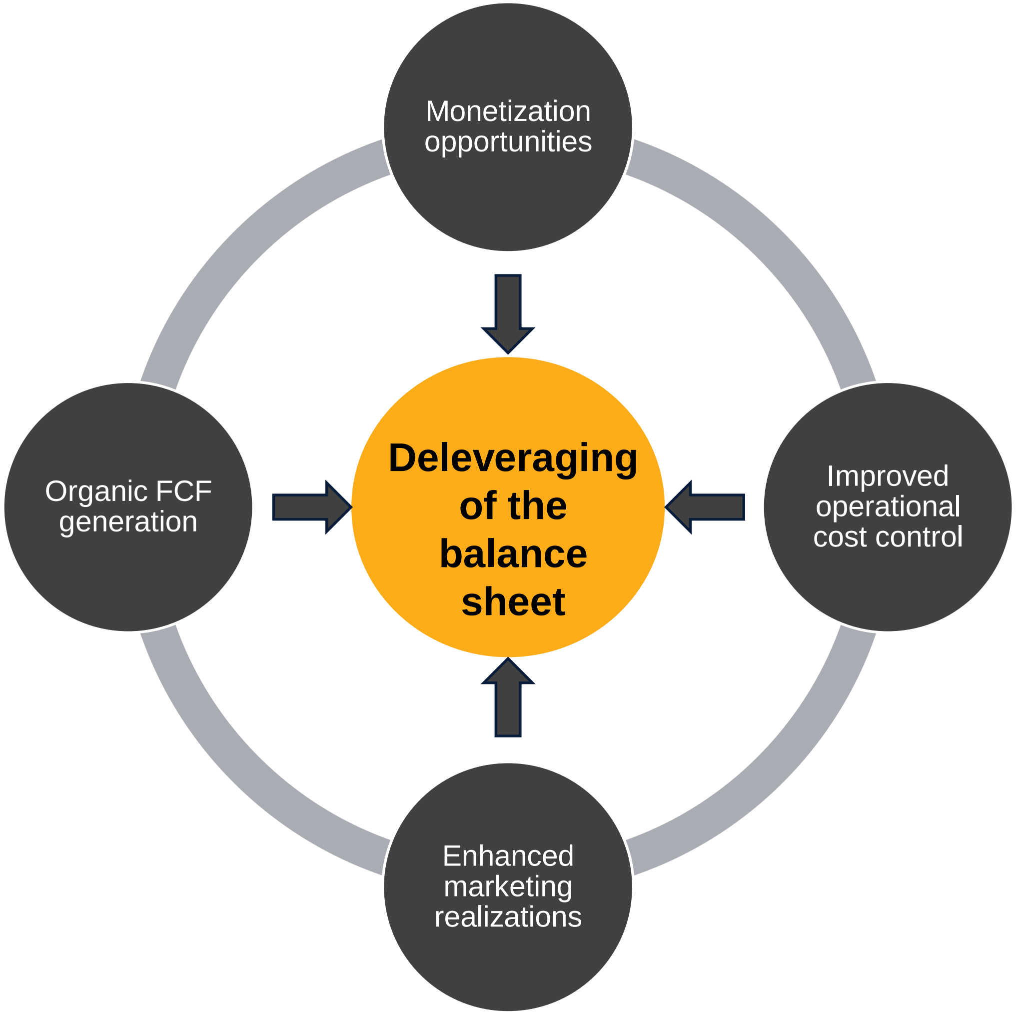
WTI INDEX PRICE SENSITIVITY[3]



1. Excludes short call positions in 3Q21 and 4Q21, and swaptions in 2022. Please see hedging details in Appendix for more information.
2. Based on FY22 consensus estimate as of June 17, 2021.
3. Realized WTI price after hedges. Assumes constant MEH and Brent pricing. Based on quarterly consensus production as of June 17, 2021.

MULTIPLE INITIATIVES DRIVING DEBT REDUCTION

- Organic adjusted free cash flow generation
  - Combined $146.8 million in adjusted FCF since 2Q20[1]
  - Projecting $500 to $800 million through 2023 at oil prices between $50 and $60 WTI per barrel[2]
- Monetization opportunities
  - Recently signed PSAs for ~$40 million
  - Currently targeting $125 to $225 million for FY 2021
  - Completed transactions for $170 million in 2020
- Enhanced marketing realizations and cost control
  - Operating profit margin of $33.46 per Boe in 1Q21
  - Unhedged EBITDA[3] of $31.97 per Boe in 1Q21
  - Pre-hedge oil realization of 99% of NYMEX
  - Weighted average barrel increasingly exposed to Brent-linked pricing



1. Adjusted free cash flow total based on 2Q FY20 to 1Q FY21. Adjusted Free Cash Flow is a non-GAAP measure. Please see the appendix for reconciliations to the nearest GAAP measures.
2. Estimated value for combined FCF generation from 2021-2023 at $50-$60/Bbl WTI utilizing a reinvestment rate of 75% for 2022 and 2023.
3. Unhedged EBITDA excludes gain/loss on commodity derivative settlements.

FINANCIAL POSITION

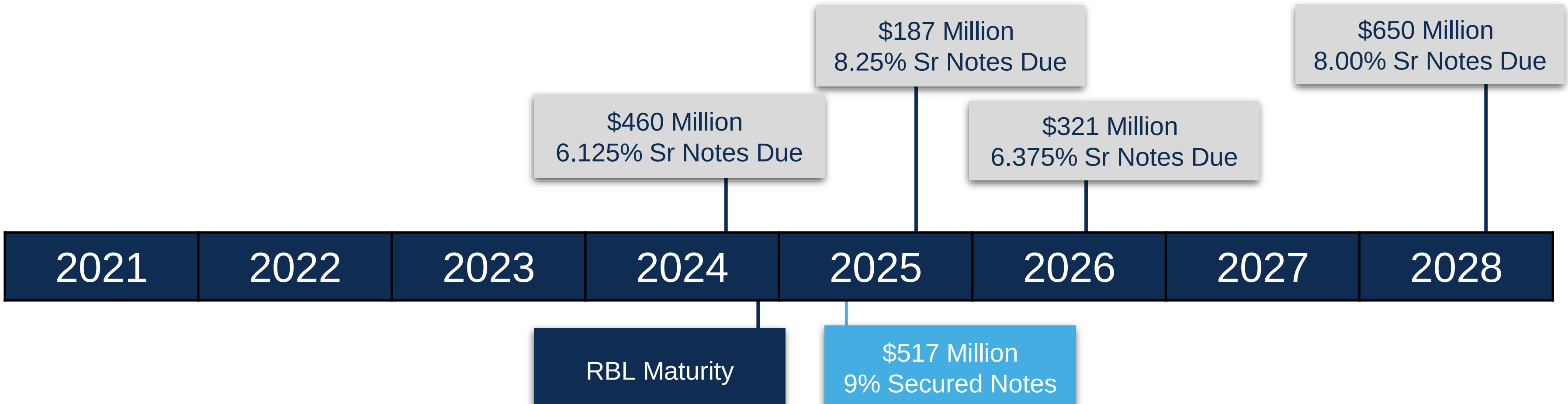
HIGHLIGHTS

- Path to further debt reduction
  - Adjusted FCF positive in 1Q21 despite winter storm impact
  - Monetization opportunities improving with increasing commodity prices
- Advancing our financial priorities
  - Borrowing base reaffirmed at $1.6 billion as of May 3, 2021
  - Net Debt / LQA EBITDA[1] estimated < 3x by 3Q21
  - 2028 senior notes offering[2] with $650 million issued at 8.00%, redeeming all 2023 notes outstanding and paying down revolver by ~$100mm
- Key near-term goals
  - < 2.5x Net Debt / Adjusted EBITDA by YE 2022
  - Absolute debt reduction from organic free cash flow and asset monetizations

CAPITALIZATION TABLE (pro forma for 2028 notes)

$ Million	1Q21
Cash	$24
Credit Facility	$854
Second Lien Notes	$517
Senior Notes	$1,618
Total Net Debt	$2,965
Total Borrowing Base	$1,600

LONGER DATED MATURITIES



1. Annualized Adjusted EBITDA, a non-GAAP measure.
2. The 2028 unsecured senior notes offering will not close until July 6. Redemption of the 2023 notes are contingent upon close of the offering.

GUIDING PRINCIPLES FOR A SUSTAINABLE BUSINESS

< 5%

Year-Over-Year

Production Growth

Commitment to Sustainable

Free Cash Flow

Returning Value to Shareholders

Continued ESG Improvement

65% - 75%

Reinvestment Rate

Commitment to Life-of-Field / Co-development

APPENDIX

2021 GUIDANCE

	PRIOR GUIDANCE	PENDING GUIDANCE
Total production (MBoe/d)	90.0 - 92.0	**89.0 - 91.0**
Oil	63%	**64%**
NGL	18%	**19%**
Gas	19%	**17%**
Income statement expenses (in millions, except where noted)		
LOE, including workovers	$190.0 - $210.0	**$185.0 - $205.0**
Gathering, Processing, and Transportation	$70.0 - $80.0	**$67.5 - $77.5**
Production and ad valorem taxes (% of total oil, natural gas, and NGL revenues)	6.5%	**6.5%**
Adjusted G&A: cash component[1]	$35.0 - $45.0	**$35.0 - $45.0**
Adjusted G&A: non-cash component[2]	$5.0 - $15.0	**$5.0 - $15.0**
Cash interest expense, net	$80.0 - $90.0	**$80.0 - $90.0**
Estimated effective income tax rate	22%	**22%**
Capital expenditures (in millions, accrual basis)		
Total Operational Capital[3]	$430.0	**$430.0**
Capitalized interest[4]	$95.0 - $105.0	**$95.0 - $105.0**
Capitalized G&A	$28.0 - $38.0	**$28.0 - $38.0**
Gross Operated Wells Drilled / Completed	55 - 65 / 90 - 100	**55 - 65 / 90 - 100**

1. Excludes the change in fair value and amortization of share-based incentive awards and other non-recurring expenses.
2. Amortization of equity-settled, share based incentive awards and other non-recurring expenses.
3. Includes drilling, completions, facilities, and equipment, but excludes land, seismic, and capitalized expenses.
4. Capitalized interest includes both cash and non-cash capitalized items.

OIL HEDGES[1]

	2Q21	3Q21	4Q21	2Q21-4Q21	1Q22	2Q22	3Q22	4Q22	FY 2022
NYMEX WTI (Bbls, $/Bbl)									
Swaps									
Total Volumes	728,000	552,000	552,000	1,832,000	225,000	227,500	460,000	460,000	1,372,500
Total Daily Volumes	8,000	6,000	6,000	6,662	2,500	2,500	5,000	5,000	3,760
Avg. Swap	$44.98	$42.10	$42.10	$43.24	$60.00	$60.00	$60.00	$60.00	$60.00
Collars									
Total Volumes	2,776,025	2,772,325	2,750,450	8,298,800	1,440,000	1,365,000	460,000	460,000	3,725,000
Total Daily Volumes	30,506	30,134	29,896	30,177	16,000	15,000	5,000	5,000	10,205
Avg. Short Call Price	$46.59	$49.14	$49.18	$48.30	$61.80	$64.58	$70.00	$70.00	$64.84
Avg. Long Put Price	$39.30	$40.68	$40.73	$40.24	$48.13	$52.50	$60.00	$60.00	$52.66
Total WTI Volume Hedged (Bbls)	3,504,025	3,324,325	3,302,450	10,130,800	1,665,000	1,592,500	920,000	920,000	5,097,500
Average WTI Ceiling Price ($/Bbl)	$46.26	$47.97	$47.99	$47.39	$61.55	$63.93	$65.00	$65.00	$63.54
Average WTI Floor Price ($/Bbl)	$40.48	$40.92	$40.96	$40.78	$49.73	$53.57	$60.00	$60.00	$54.64
ICE BRENT (Bbls, $/Bbl)									
Swaps									
Total Volumes	221,300	-	-	221,300	-	-	-	-	-
Total Daily Volumes	2,432	-	-	805	-	-	-	-	-
Avg. Swap	$37.35	-	-	$37.35	-	-	-	-	-
Collars									
Total Volumes	182,000	184,000	184,000	550,000	-	-	-	-	-
Total Daily Volumes	2,000	2,000	2,000	2,000	-	-	-	-	-
Avg. Short Call Price	$50.00	$50.00	$50.00	$50.00	-	-	-	-	-
Avg. Long Put Price	$45.00	$45.00	$45.00	$45.00	-	-	-	-	-
Total Brent Volume Hedged (Bbls)	403,300	184,000	184,000	771,300	-	-	-	-	-
Average Brent Ceiling Price ($/Bbl)	$43.06	$50.00	$50.00	$46.37	-	-	-	-	-
Average Brent Floor Price ($/Bbl)	$40.80	$45.00	$45.00	$42.81	-	-	-	-	-
MAGELLAN EAST HOUSTON FIXED PRICE (Bbls, $/Bbl)									
Collars									
Total Volumes	409,500	-	-	409,500	225,000	227,500	-	-	452,500
Total Daily Volumes	4,500	-	-	1,489	2,500	2,500	-	-	2,500
Avg. Short Call Price	$47.00	-	-	$47.00	$63.15	$63.15	-	-	$63.15
Avg. Long Put Price	$41.00	-	-	$41.00	$51.25	$51.25	-	-	$51.25
MIDLAND-CUSHING DIFFERENTIAL (Bbls, $/Bbl)									
Swaps									
Total Volumes	667,500	612,000	892,400	2,171,900	-	-	-	-	-
Total Daily Volumes	7,335	6,652	9,700	7,898	-	-	-	-	-
Avg. Swap Price	$0.21	$0.13	$0.33	$0.24	-	-	-	-	-

1. Callon hedge portfolio as of 06/15/2021. In addition to the above hedges, Callon holds short the following positions: 13,220 bpd 2H21 WTI calls (avg. strike $63.62), 5,000 bpd Cal22 $52.18-strike WTI swaptions, and 5,000 bpd Cal23 $72.00-strike swaptions. Callon owes deferred premiums for 2Q21-2Q22 of the following amounts ($MM): $6.7, $2.7, $2.7, $2.0, $0.9. In February 2021, we executed offsetting ICE Brent swaps on 159,300 Bbls, resulting in a locked-in loss of approximately $2.9 million which we will pay as the applicable contracts settle.

GAS AND NGL HEDGES[1]

	2Q21	3Q21	4Q21	2Q21-4Q21	1Q22	2Q22	3Q22	4Q22	FY 2022
NYMEX HENRY HUB (MMBtu, $/MMBtu)									
Swaps									
Total Volumes	3,822,000	3,864,000	3,437,000	11,123,000	-	910,000	920,000	310,000	2,140,000
Total Daily Volumes	42,000	42,000	37,359	40,447	-	10,000	10,000	3,370	5,863
Avg. Swap Price	$2.59	$2.59	$2.62	$2.60	-	$2.65	$2.65	$2.65	$2.65
Collars									
Total Volumes	1,820,000	1,840,000	1,840,000	5,500,000	3,600,000	-	-	-	3,600,000
Total Daily Volumes	20,000	20,000	20,000	20,000	40,000	-	-	-	9,863
Avg. Short Call Price	$2.80	$2.80	$2.80	$2.80	$3.75	-	-	-	$3.75
Avg. Long Put Price	$2.50	$2.50	$2.50	$2.50	$2.83	-	-	-	$2.83
Total NYMEX Volume Hedged (MMBtu)	5,642,000	5,704,000	5,277,000	16,623,000	3,600,000	910,000	920,000	310,000	5,740,000
Average NYMEX Ceiling Price ($/MMBtu)	$2.66	$2.66	$2.69	$2.67	$3.75	$2.65	$2.65	$2.65	$3.34
Average NYMEX Floor Price ($/MMBtu)	$2.56	$2.56	$2.58	$2.57	$2.83	$2.65	$2.65	$2.65	$2.76
WAHA DIFFERENTIAL (MMBtu, $/MMBtu)									
Swaps									
Total Volumes	4,095,000	4,140,000	4,140,000	12,375,000	1,350,000	1,365,000	1,380,000	1,380,000	5,475,000
Total Daily Volumes	45,000	45,000	45,000	45,000	15,000	15,000	15,000	15,000	15,000
Avg. Swap Price	($0.42)	($0.42)	($0.42)	($0.42)	($0.21)	($0.21)	($0.21)	($0.21)	($0.21)
MT. BELVIEU PURITY ETHANE (Bbls/$/Bbl)									
Swaps									
Total Volumes	455,000	460,000	460,000	1,375,000	-	-	-	-	-
Total Daily Volumes	5,000	5,000	5,000	5,000	-	-	-	-	-
Avg. Swap Price	$7.62	$7.62	$7.62	$7.62	-	-	-	-	-

1. Callon hedge portfolio as of 06/07/2021. In addition to the above hedge positions, Callon holds short 20,000 mmbtu/d Cal21 calls (avg. strike $3.09).

CAP

NON-GAAP ADJUSTED EBITDA[1]

($000s)	1Q 21
Net loss	($80,407)
Loss on derivative contracts	214,523
Loss on commodity derivative settlements, net	(62,280)
Non-cash stock-based compensation expense	7,608
Other income	(3,306)
Income tax benefit	(921)
Interest expense	24,416
Depreciation, depletion and amortization	70,987
Adjusted EBITDA	$170,620
Loss on commodity derivative settlements, net	62,280
Unhedged EBITDA	$232,900
Total MBOE	7,286
Unhedged EBITDA per Boe	$31.97

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

NON-GAAP ADJUSTED FREE CASH FLOW[1]

($000s)	2Q 20	3Q 20	4Q 20	1Q 21
Net cash provided by operating activities	$97,801	$135,701	$134,578	$137,665
Changes in working capital and other	40,078	14,473	12,011	30,913
Change in accrued hedge settlements	(14,480)	(5,993)	(5,055)	(20,117)
Cash interest expense, net	21,944	24,246	24,167	22,159
Merger and integration expense	8,067	2,465	2,120	--
Adjusted EBITDA	$153,410	$170,892	$167,821	$170,620
Less: Operational capital expenditures (accrual)	85,087	38,408	87,488	95,545
Less: Capitalized interest	20,924	20,675	23,015	21,817
Less: Interest expense, net of capitalized amounts	22,682	24,683	26,486	22,159
Less: Capitalized cash G&A	6,740	6,831	6,465	6,913
Adjusted Free Cash Flow[2]	$17,977	$80,295	$24,367	$24,186

1. See "Important Disclosures" slide for additional information related to Supplemental Non-GAAP Financial Measures.
2. Effective January 1, 2021, non-cash interest expense amounts consisting primarily of amortization of debt issuance costs, premiums, and discounts associated with our long-term debt are excluded from our calculation of adjusted free cash flow.

NON-GAAP ADJUSTED G&A – CASH COMPONENT AND FULL CASH G&A COSTS[1]

($000s)	FY 20	1Q 21
Total G&A	$37,187	$16,799
Change in the fair value of liability share-based awards (non-cash)	4,110	(5,943)
Adjusted G&A – total	41,297	10,856
Equity-settled, share-based compensation (non-cash) and other non-recurring expenses	(7,771)	(1,665)
Adjusted G&A — cash component	$33,526	$9,191
Capitalized cash G&A	27,606	6,913
Full Cash G&A	$61,132	$16,104

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

NON-GAAP NET DEBT RECONCILIATION[1]

	As of March 31, 2021
	(in millions)
Long-term debt	$2,978
Less: Cash and cash equivalents	24
Net Debt	$2,954

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