Answering the Call for Affordable, Reliable, Lower Carbon Energy

1Q 2022 EARNINGS / MAY 4, 2022

CHESAPEAKE ENERGY

Forward-Looking Statements

This presentation and the accompanying outlook include “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 are statements other than statements of historical fact. They include statements that give our current expectations, management’s outlook guidance or forecasts of future events, expected natural gas and oil growth trajectory, projected cash flow and liquidity, our ability to enhance our cash flow and financial flexibility, dividend plans, future production and commodity mix, plans and objectives for future operations, ESG initiatives, the ability of our employees, portfolio strength and operational leadership to create long-term value, and the assumptions on which such statements are based. Although we believe the expectations and forecasts reflected in our forward-looking statements are reasonable, they are inherently subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. No assurance can be given that such forward-looking statements will be correct or achieved or that the assumptions are accurate or will not change over time.

Factors that could cause actual results to differ materially from expected results include those described under “Risk Factors” in Item 1A of our annual report on Form 10-K and any updates to those factors set forth in Chesapeake’s subsequent quarterly reports on Form 10-Q or current reports on Form 8-K (available at http://www.chk.com/investors/sec-filings). These risk factors include: the ability to execute on our business strategy following emergence from bankruptcy; inflation and commodity price volatility resulting from Russia’s invasion of Ukraine, COVID-19 and related supply chain constraints, along with the effect on our business, financial condition, employees, contractors and vendors, and on the global demand for oil and natural gas and U.S. and world financial markets; risks related to the acquisition of Chief E&D Holdings, LP and affiliates of Tug Hill, Inc. (together, “Chief”), including our ability to successfully integrate the business of Chief into the company and achieve the expected synergies from the Chief acquisition within the expected timeframe; the volatility of oil, natural gas and NGL prices; the limitations our level of indebtedness may have on our financial flexibility; our inability to access the capital markets on favorable terms; the availability of cash flows from operations and other funds to fund cash dividends, to finance reserve replacement costs or satisfy our debt obligations; write-downs of our oil and natural gas asset carrying values due to low commodity prices; our ability to replace reserves and sustain production; uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and projecting future rates of production and the amount and timing of development expenditures; our ability to generate profits or achieve targeted results in drilling and well operations; leasehold terms expiring before production can be established; commodity derivative activities resulting in lower prices realized on oil, natural gas and NGL sales; the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations; adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims; charges incurred in response to market conditions; drilling and operating risks and resulting liabilities; effects of environmental protection laws and regulations on our business; legislative and regulatory initiatives further regulating hydraulic fracturing; our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used; impacts of potential legislative and regulatory actions addressing climate change; federal and state tax proposals affecting our industry; potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations; competition in the oil and gas exploration and production industry; a deterioration in general economic, business or industry conditions; negative public perceptions of our industry; limited control over properties we do not operate; pipeline and gathering system capacity constraints and transportation interruptions; terrorist activities and cyber-attacks adversely impacting our operations; and an interruption in operations at our headquarters due to a catastrophic event.

In addition, disclosures concerning the estimated contribution of derivative contracts to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility. Our production forecasts are also dependent upon many assumptions, including estimates of production decline rates from existing wells and the outcome of future drilling activity. We caution you not to place undue reliance on our forward-looking statements that speak only as of the date of this presentation, and we undertake no obligation to update any of the information provided in this presentation, except as required by applicable law. In addition, this presentation contains time-sensitive information that reflects management’s best judgment only as of the date of this presentation.

1Q'22 Highlights

Adjusted free cash flow[1]
$532mm
FY'22E projection raised to $2.6B – $2.8B

Adjusted EBITDAX[1]
$913mm
FY'22E projection raised to $4.6B – $4.8B

Dividend payable
$2.34
per share in June 2022

'22E total dividend yield[2]
~10%
14% cash yield with buyback

Net debt-to-EBITDAX ratio[1]
~0.6x
projected at YE'22

Total dividends payable in '22E
$1.1B – $1.3B
>$7B estimated dividends payable[1] over next 5 years

Initiated repurchase program
$83mm
$1B authorization through YE'23

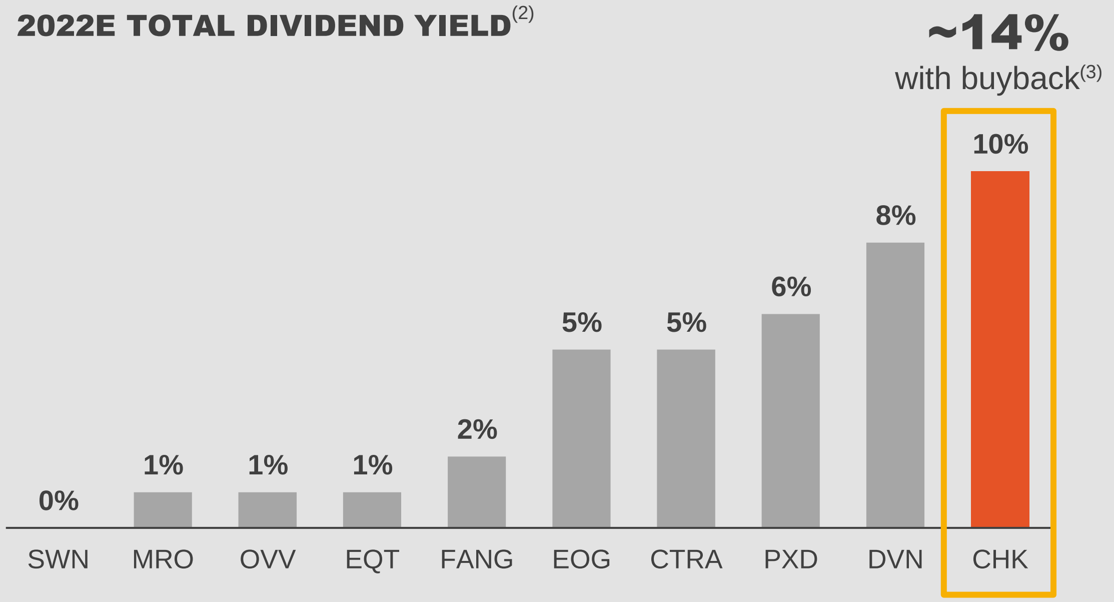
(1) Assumes projections and outlook as of 5/4/2022. A non-GAAP measure as defined in the appendix. 3/31/2022 net debt balance as a ratio to midpoint of projected 2022 EBITDAX.
(2) Total dividend yield is calculated as projected base and variable dividends per common share divided by 4/29/2022 share price. Cash yield assumes $500 million of authorized share repurchase program utilized in 2022.

Best-in-Class Dividend Program

Share and warrant repurchase program commences, leading to double-digit cash returns[1]

- **$2.34 per share payable in June 2022**
  - $0.50 base dividend
  - $1.84 variable dividend
- **Anticipate paying $1.1B – $1.3B in total dividends in 2022 (~10% current yield)[1]**
  - 2Q'22E projected total dividends paid of $290mm – $300mm
  - Total estimated dividends of >$7B over the next five years[1]
- **Commenced share and warrant repurchase program**
  - $83mm in common shares in 1Q'22
  - $1B authorized through YE'23

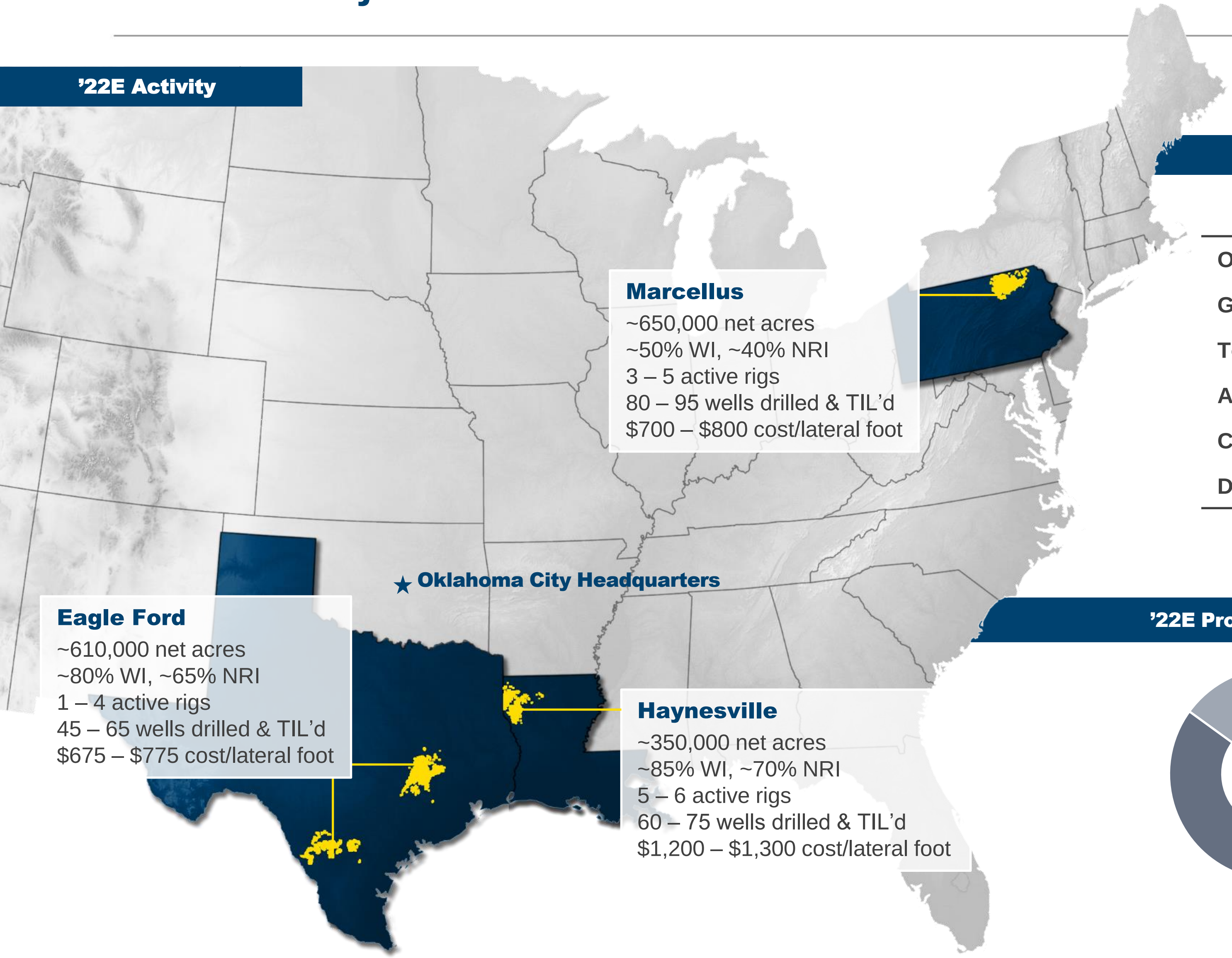
2022E TOTAL DIVIDEND YIELD[2]



(1) Based on 4/29/2022 strip price and 5/2/2022 CHK stock price.
(2) Total dividend yield is calculated as base and variable dividends per common share divided by 5/2/2022 share price.
(3) Assumes $500 million of common shares repurchased during 2022.

2022 Projected Plan

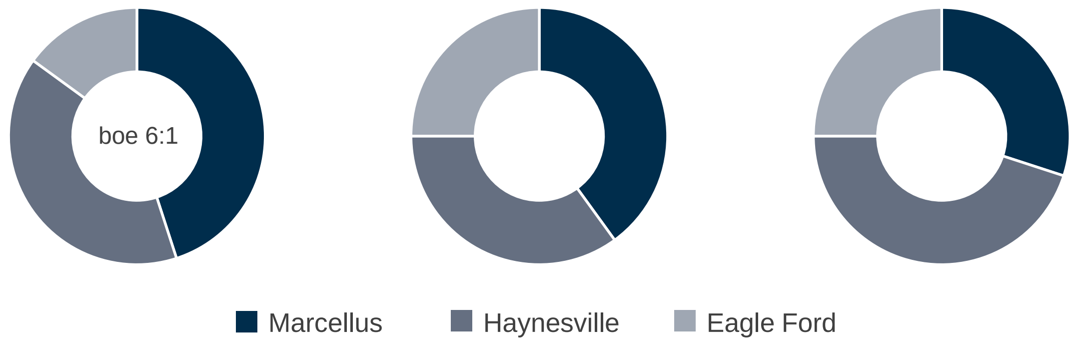
'22E Activity



1Q'22 Actual and 2022E Projected Results

	1Q'22	2Q'22E	FY'22E
Oil Production (mbo/d)	60	48 – 50	51 – 56
Gas Production (bcf/d)	3.2	3.7 – 3.8	3.6 – 3.7
Total Production (mboe/d)	620	685 – 690	670 – 690
Adj. EBITDAX ($mm)	$913	$1,000 – $1,100	$4,600 – $4,800
Capex ($mm)	$339	$500 – $550	$1,500 – $1,800
Dividends Payable ($mm)	$211	$295 – $305	$1,100 – $1,300

'22E Production Outlook | '22E EBITDAX Outlook | '22E Capital Plan

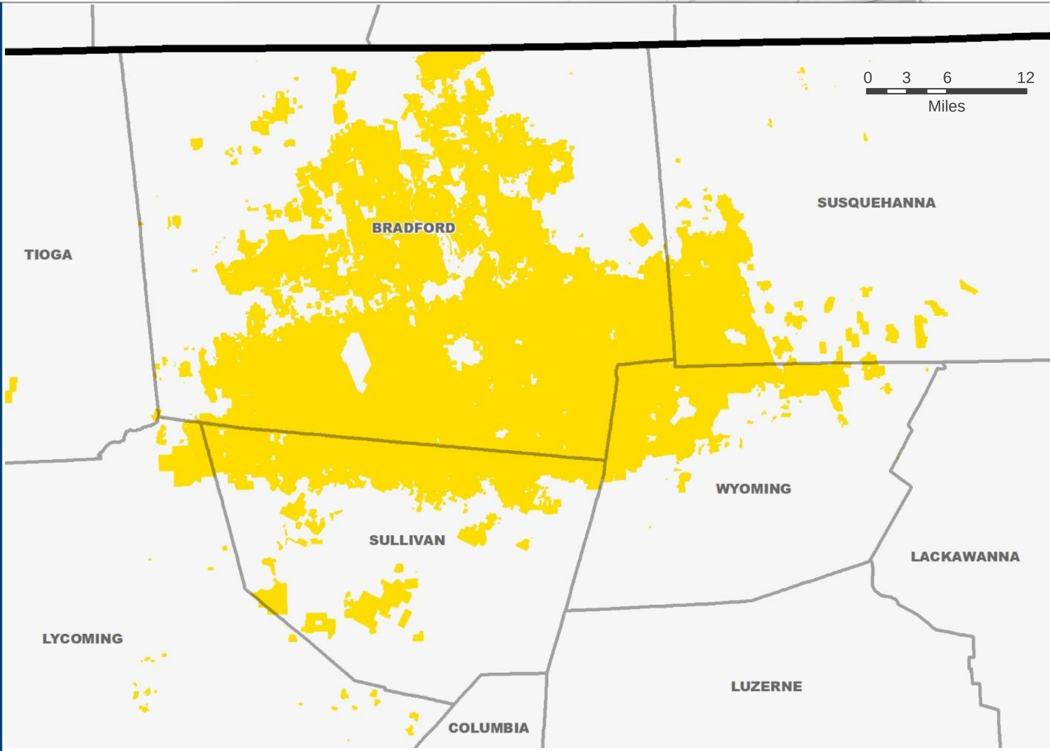


Note: All values assume closing of Chief assets on 3/9/2022 and divestiture of Powder River Basin assets on 3/25/2022.

Marcellus: Premium Scale, Leading Returns

Asset overview	1Q'22	2Q'22E	FY'22E
Net Production (bcf/d)	1.45	1.85 – 1.95	1.9 – 2.0
Wells Drilled	14	24 – 28	80 – 95
Wells TIL'd	17	24 – 28	80 – 95
Average LL (feet)			~11,000
PDP Decline (5 year)			~20%
2022 TIL Decline (1 year)			~60%

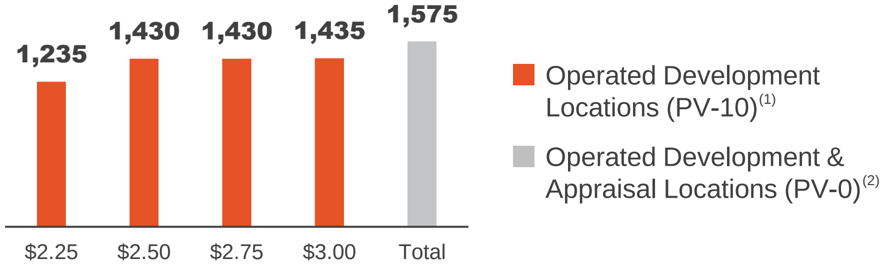
Cost assumptions (net)	1Q'22	2Q'22E	FY'22E
Differential to NYMEX ($/mcf)	($0.29)		($0.50) – ($0.60)
LOE ($/mcf)	$0.10		$0.09 – $0.11
GP&T ($/mcf)	$0.55		$0.55 – $0.65
Total Capital ($mm)	$64	$140 – $150	$425 – $525



'22E Production Outlook

'22E EBITDAX Outlook

'22E Capital Plan



Location Assumptions: Average Lateral Length = 9,800'
1,300' – 1,500' Average Spacing (4 WPS)

(1) 10% ROR at current spacing assumption, proven development zones.
(2) Location counts are based on existing acreage and do not include exploration wells or zones still in early evaluation.

Haynesville: Profitable Growth, Advantaged Markets

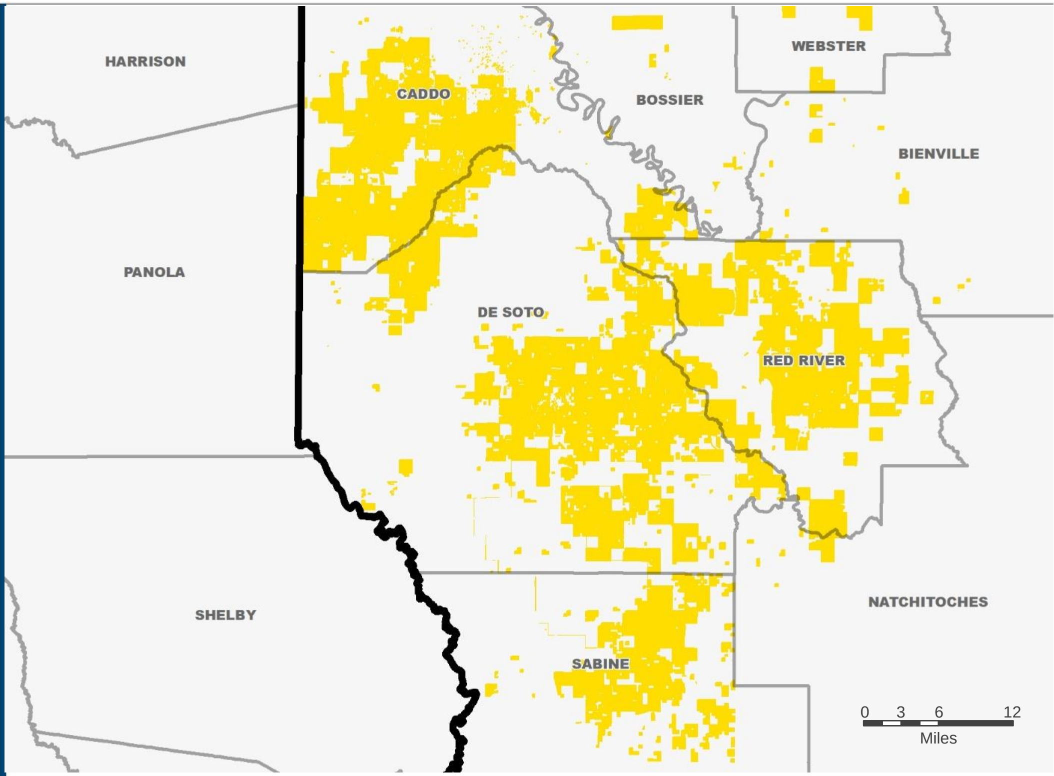
Asset overview	1Q'22	2Q'22E	FY'22E
Net Production (bcf/d)	1.63	1.65 – 1.75	1.6 – 1.7
Wells Drilled	12	15 – 20	60 – 75
Wells TIL'd	20	15 – 20	60 – 75
Average LL (feet)			~9,000
PDP Decline (5 year)			~30%
2022 TIL Decline (1 year)			~65%

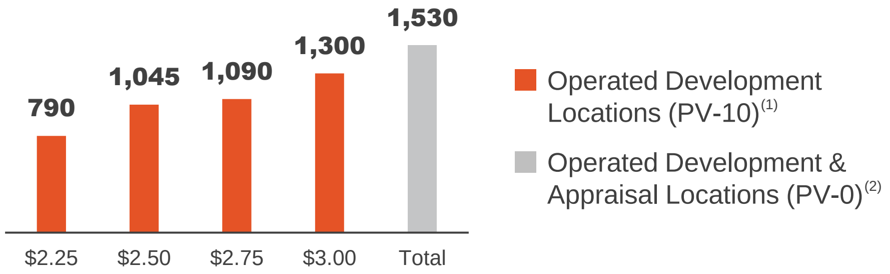
Cost assumptions (net)	1Q'22	2Q'22E	FY'22E
Differential to NYMEX ($/mcf)	($0.49)		($0.55) – ($0.65)
LOE ($/mcf)	$0.22		$0.25 – $0.35
GP&T ($/mcf)	$0.45		$0.45 – $0.55
Total Capital ($mm)	$200	$210 – $220	$675 – $775

'22E Production Outlook

'22E EBITDAX Outlook

'22E Capital Plan





Location Assumptions: Average Lateral Length = 7,500'
1,250' – 1,750' Average Spacing (4 WPS)

(1) 10% ROR at current spacing assumption, proven development zones.
(2) Location counts are based on existing acreage and do not include exploration wells or zones still in early evaluation.

Eagle Ford: Superior Margins, Sustainable Free Cash Flow

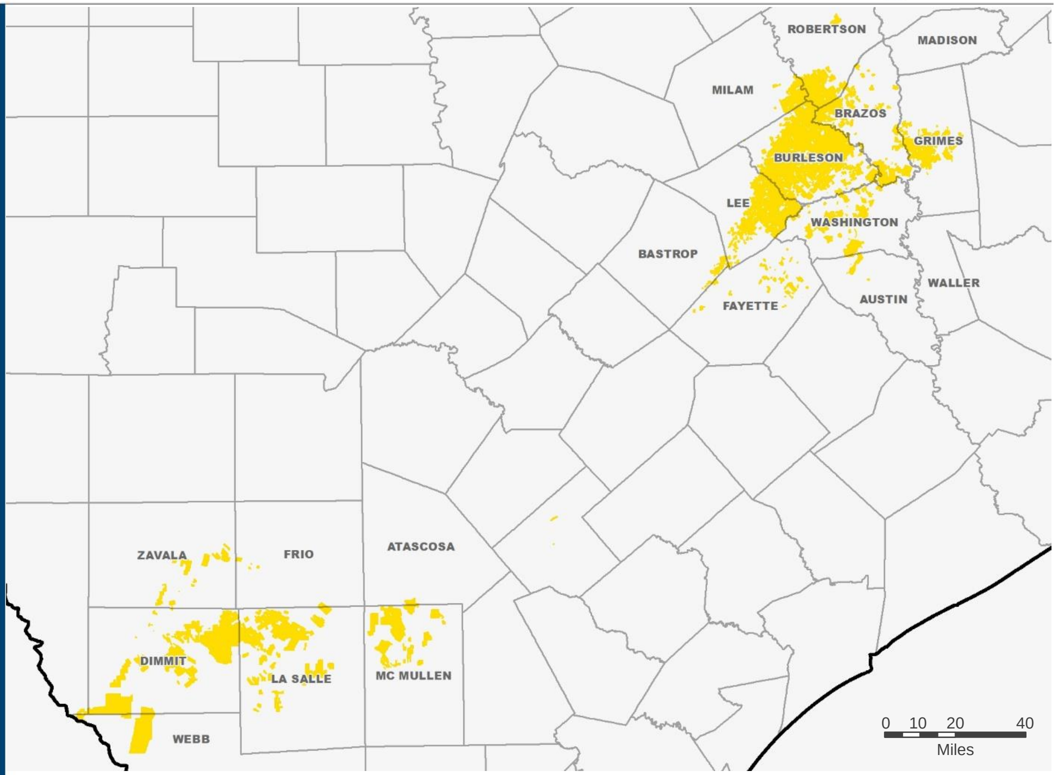
Asset overview	1Q'22	2Q'22E	FY'22E
Net Production (mboe/d)	90	85 – 95	90 – 100
Wells Drilled	10	30 – 35	45 – 65
Wells TIL'd	0	10 – 15	45 – 65
Average LL (feet)			~10,500
PDP Decline (5 year)			~15%
2022 TIL Decline (1 year)			~70%

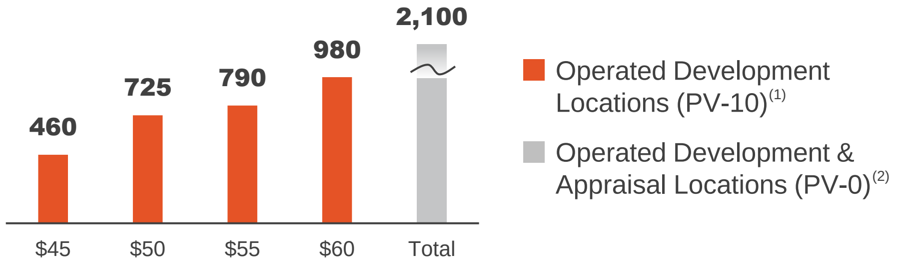
Cost assumptions (net)	1Q'22	2Q'22E	FY'22E
Differential to NYMEX ($/bbl)	$0.71		$0.50 – $0.90
LOE ($/boe)	$6.87		$6.50 – $6.75
GP&T ($/boe)	$10.41		$9.50 – $10.50
Total Capital ($mm)	$50	$165 – $175	$375 – $475

'22E Production Outlook

'22E EBITDAX Outlook

'22E Capital Plan





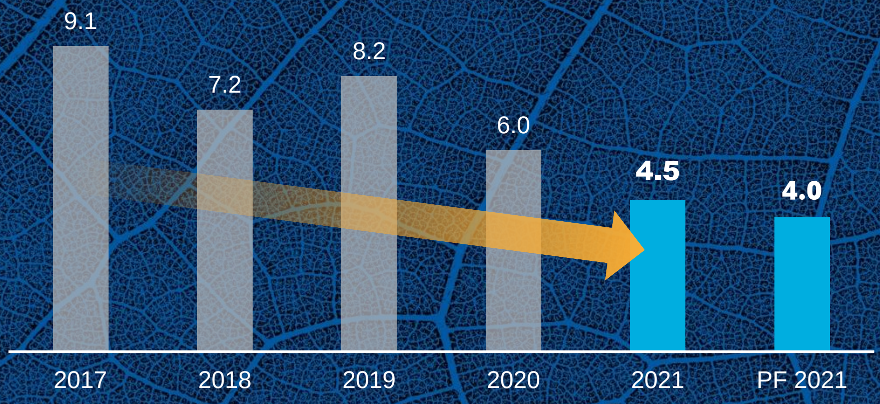
Location Assumptions: Average Lateral Length = 9,600'
750' – 2,000' avg. spacing (2 – 6 WPS)

(1) 10% ROR at current spacing assumption, proven development zones.
(2) Location counts are based on existing acreage and do not include exploration wells or zones still in early evaluation.

Reducing Direct GHG and Methane Emissions

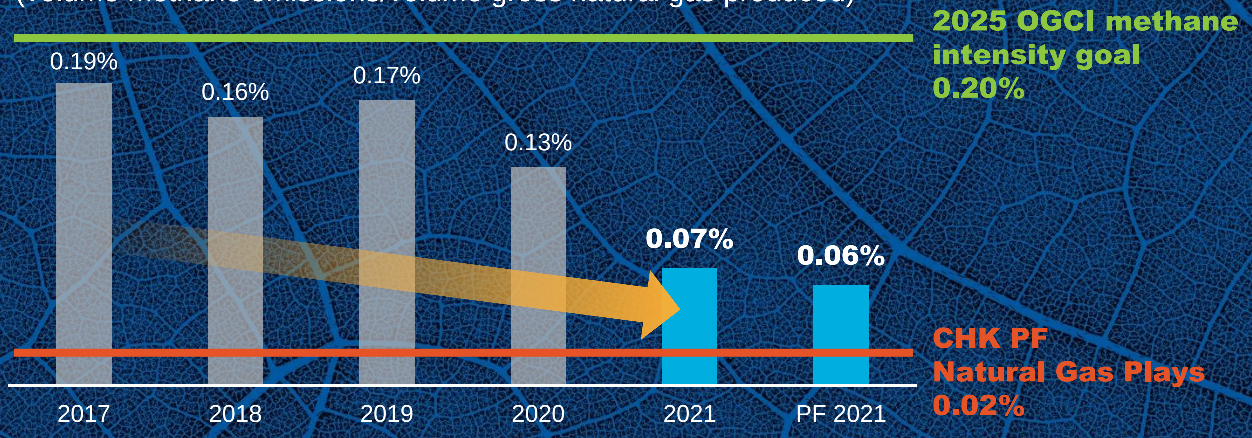
CHK GHG Emissions Intensity

(metric tons CO_2e/gross mboe produced)

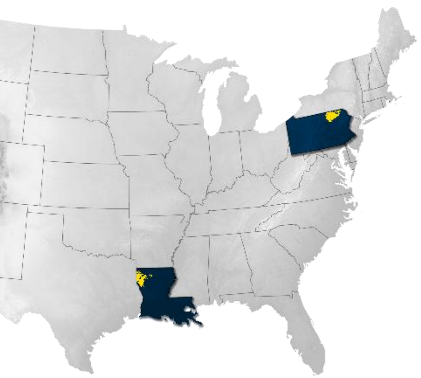


CHK Methane Intensity

(volume methane emissions/volume gross natural gas produced)



➤ Advancing Our Sustainability Commitments



100% RSG certified in Haynesville

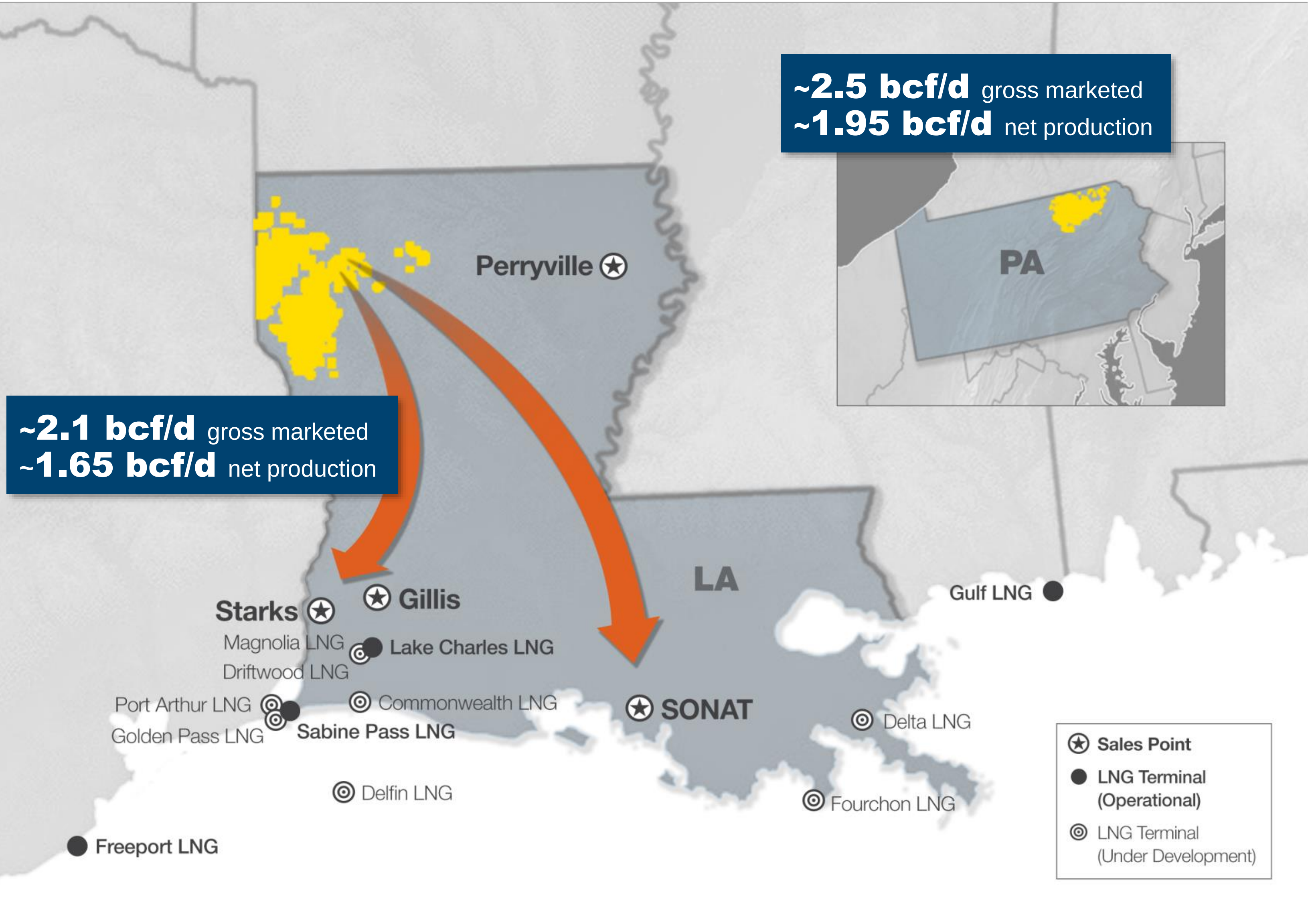
Projected to be 100% RSG certified in Marcellus by YE'22

Intend to invest >$30mm in ESG initiatives, including retrofitting >19,000 pneumatic devices by end of 2022, reducing reported GHG emissions[(1)] by ~40% and methane emissions by ~80%

(1) As reported under 40 CFR 98 Subpart W.

Leading RSG Supplier to LNG Export Markets

- **Supplying RSG to the Gulf Coast and LNG export markets**
  - Actively engaged in several discussions regarding participating in LNG export market
  - All Haynesville production completed RSG certification at YE'21
  - Projected to be 100% RSG certified in Marcellus by YE'22



EAGLE FORD

MARCELLUS

HAYNESVILLE

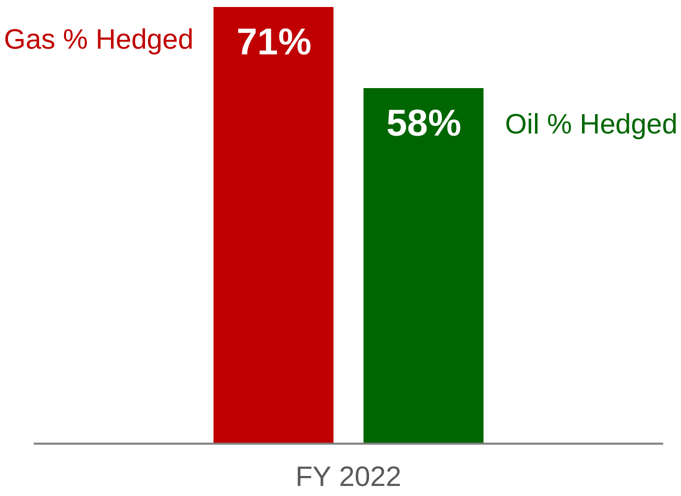
Appendix

CHESAPEAKE ENERGY

Hedging Program Reduces Risk, Protects Returns

➤ Since 2/21/2022, CHK has hedged:
- 81 bcf of 2023 gas at $3.48 – $7.29/mcf
- 1.1 mmbbl of 2023 oil at $79.83 – $94.07/bbl

DOWNSIDE PROTECTION LEVELS	RMDR 2022[(1)]	2023
Gas, $/mcf	$2.90 – $3.40	$2.96 – $3.96
Oil, $/bbl	$44.59	$62.52 – $72.93



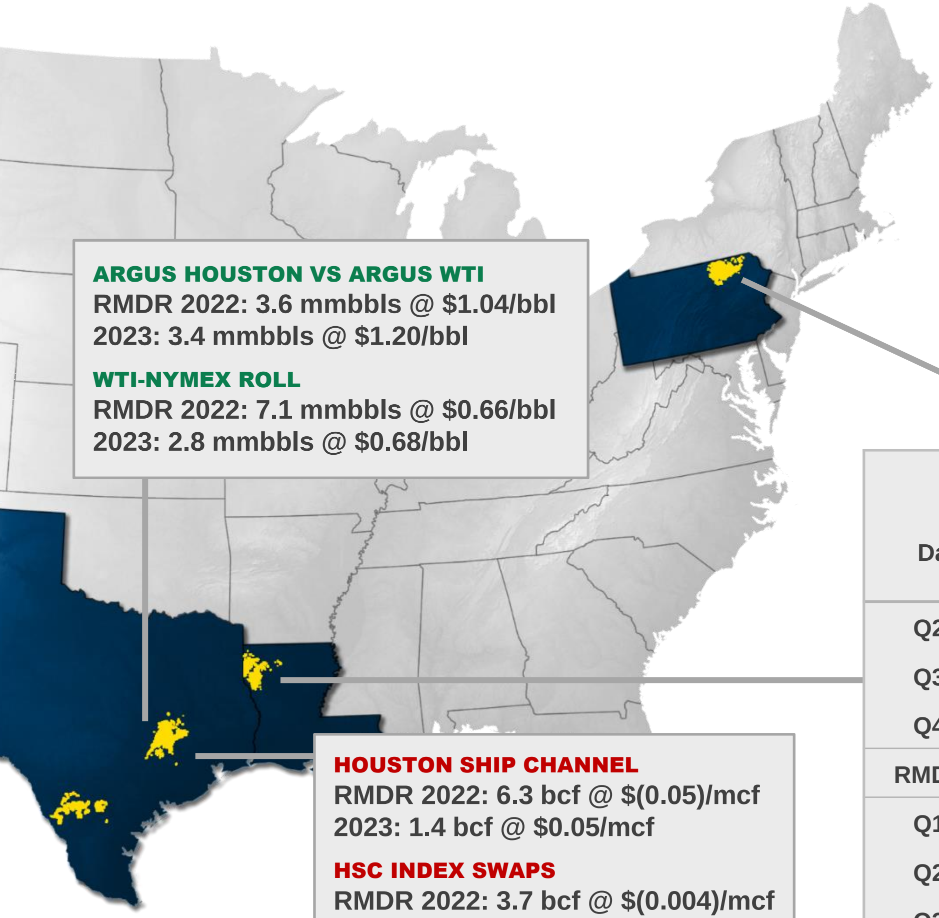
	NATURAL GAS													OIL				
	SWAPS		SWAPTIONS		COLLARS			THREE-WAY COLLARS				CALLS		SWAPS		COLLARS		
Date	Volume *bcf*	Price *$/mcf*	Volume *bcf*	Price *$/mcf*	Volume *bcf*	Bought Put *$/mcf*	Sold Call *$/mcf*	Volume *bcf*	Sold Put *$/mcf*	Bought Put *$/mcf*	Sold Call *$/mcf*	Volume *bcf*	Sold Call *$/mcf*	Volume *mmbbl*	Price *$/bbl*	Volume *mmbbl*	Bought Put *$/bbl*	Sold Call *$/bbl*
Q2 2022	129.9	2.60	-	-	90.1	3.33	4.41	6.4	2.41	2.90	3.43	-	-	2.8	43.12	-	-	-
Q3 2022	134.0	2.63	-	-	93.8	3.41	4.56	6.4	2.41	2.90	3.43	-	-	2.7	44.85	-	-	-
Q4 2022	117.3	2.60	-	-	120.1	3.12	4.27	6.4	2.41	2.90	3.43	-	-	2.6	45.92	-	-	-
RMDR '22	**381.2**	**2.61**	**-**	**-**	**304.0**	**3.27**	**4.40**	**19.3**	**2.41**	**2.90**	**3.43**	**-**	**-**	**8.1**	**44.59**	**-**	**-**	**-**
Q1 2023	114.3	2.64	1.8	2.88	44.4	3.20	5.39	0.9	2.50	3.40	3.79	18.0	3.29	1.9	47.17	0.5	72.92	89.15
Q2 2023	28.7	2.73	1.8	2.88	92.1	3.13	4.74	0.9	2.50	3.40	3.79	-	-	-	-	2.0	66.98	81.45
Q3 2023	27.2	2.75	1.8	2.88	93.1	3.13	4.74	0.9	2.50	3.40	3.79	-	-	-	-	1.7	67.41	80.64
Q4 2023	33.3	2.69	1.8	2.88	84.7	3.14	4.86	0.9	2.50	3.40	3.79	-	-	-	-	1.2	68.42	82.29
FY 2023	**203.5**	**2.67**	**7.3**	**2.88**	**314.4**	**3.14**	**4.86**	**3.7**	**2.50**	**3.40**	**3.79**	**18.0**	**3.29**	**1.9**	**47.17**	**5.5**	**67.98**	**82.10**

Note: Hedged volume and price reflect positions as of 4/29/2022
(1) RMDR 2022 includes 2Q'22 – 4Q'22

Hedged Basis Protection

As of 4/29/2022

- 15% of Marcellus and 32% of Haynesville basis hedged for the remainder of 2022
- Since 2/21/2022, CHK has added basis protection for:
  - 113.3 bcf of 2Q'22 – 4Q'22 gas at an average differential to NYMEX of $(0.71)
  - 37.3 bcf of 2023 gas at $(0.22)



ARGUS HOUSTON VS ARGUS WTI
RMDR 2022: 3.6 mmbbls @ $1.04/bbl
2023: 3.4 mmbbls @ $1.20/bbl

WTI-NYMEX ROLL
RMDR 2022: 7.1 mmbbls @ $0.66/bbl
2023: 2.8 mmbbls @ $0.68/bbl

HOUSTON SHIP CHANNEL
RMDR 2022: 6.3 bcf @ $(0.05)/mcf
2023: 1.4 bcf @ $0.05/mcf

HSC INDEX SWAPS
RMDR 2022: 3.7 bcf @ $(0.004)/mcf

	MARCELLUS						HAYNESVILLE				TRANSPORT SPREAD[1]	
	TETCO M3		TGP Z4 300L		LEIDY		CGT MAINLINE		TGT Z1		TETCO M3	
Date	Volume *bcf*	Avg. Price *$/mcf*	Volume *bcf*	Avg. Price *$/mcf*	Volume *bcf*	Avg. Price *$/mcf*	Volume *bcf*	Avg. Price *$/mcf*	Volume *bcf*	Avg. Price *$/mcf*	Volume *bcf*	Avg. Price *$/mcf*
Q2 2022	11.8	(0.80)	4.4	(1.24)	12.6	(1.14)	43.2	(0.36)	15.5	(0.28)	11.3	0.79
Q3 2022	12.0	(0.80)	4.5	(1.24)	17.4	(1.16)	40.3	(0.37)	15.6	(0.28)	11.4	0.79
Q4 2022	8.5	0.60	2.8	(1.08)	7.1	(1.10)	34.4	(0.29)	8.6	(0.23)	9.9	0.77
RMDR '22	**32.2**	**(0.43)**	**11.7**	**(1.20)**	**37.1**	**(1.14)**	**118.8**	**(0.34)**	**39.7**	**(0.27)**	**32.6**	**0.78**
Q1 2023	6.5	1.88	1.9	(0.90)	1.8	(0.85)	23.0	(0.26)	5.0	(0.16)	6.8	0.76
Q2 2023	3.6	(0.86)	-	-	1.4	(1.05)	15.5	(0.27)	3.0	(0.25)	6.8	0.76
Q3 2023	3.7	(0.86)	-	-	1.4	(1.05)	15.6	(0.27)	3.0	(0.25)	6.9	0.76
Q4 2023	3.7	0.54	1.5	(0.82)	1.4	(0.84)	14.9	(0.24)	2.4	(0.20)	2.9	0.76
FY 2023	**17.5**	**0.45**	**3.4**	**(0.86)**	**5.9**	**(0.94)**	**68.9**	**(0.26)**	**13.3**	**(0.21)**	**23.4**	**0.76**

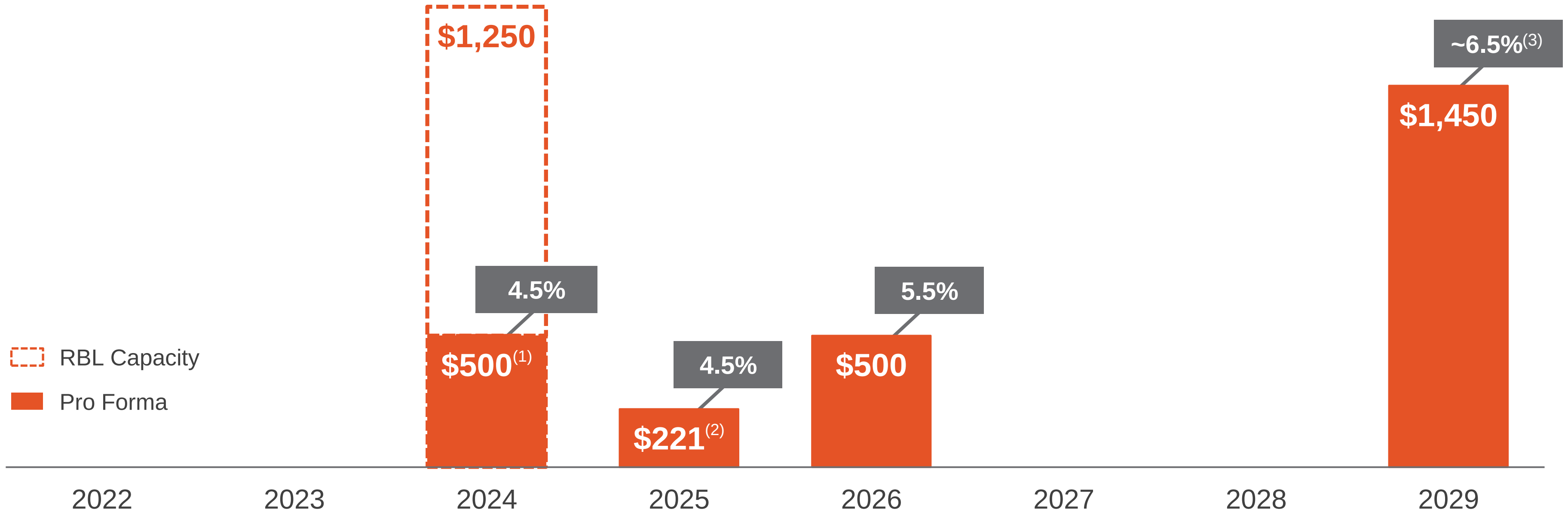
(1) TETCO M3 transport spread vs. TGP Z4 300L

Pro Forma Maturity Profile

PF net debt-to-2022E EBITDAX ratio(1)

~0.6x

Preserving balance sheet strength



(1) A non-GAAP measure as defined in the appendix. Net debt as of 3/31/2022 over midpoint of 2022 Outlook
(2) Represents $221mm of CA-CIB and Natixis Tranche B
(3) $500mm at 5.875% and $950mm at 6.75%

Management's Outlook as of May 4, 2022

	2022 Projections
Production:	
Oil – mbo per day	51 – 56
NGL – mbbls per day	***15 – 18***
Natural gas – mmcf per day	3,600 – 3,680
Total daily rate – mboe per day	670 – 690
Estimated basis to NYMEX prices, based on 4/29/22 strip prices:	
Oil – $/bbl	$0.50 – $0.90
Natural gas – $/mcf	($0.45) – ($0.55)
NGL – realizations as a % of WTI	40% – 45%
Operating costs per boe of projected production:	
Production expense	***$1.75 – $2.00***
Gathering, processing and transportation expenses	***$4.00 – $4.50***
Oil – $/bbl	***$2.80 – $3.00***
Natural Gas – $/mcf	***$0.70 – $0.80***
Severance and ad valorem taxes	***$0.95 – $1.05***
General and administrative[(1)]	$0.45 – $0.65
Depreciation, depletion and amortization expense	$7.00 – $8.00
Marketing net margin and other ($ in millions)	***$25 – $50***
Interest expense ($ in millions)	$125 – $135
Cash taxes ($ in millions)	***$200 – $250***
Adjusted EBITDAX, based on 4/29/22 strip prices ($ in millions)[(2)]	***$4,600 – $4,800***
Total capital expenditures ($ in millions)	$1,500 – $1,800

(1) Includes ~$0.07/boe of expenses associated with stock-based compensation, which are recorded in general and administrative expenses in Chesapeake's Condensed Consolidated Statement of Operations.

(2) Adjusted EBITDAX is a non-GAAP measure used by management to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies. Adjusted EBITDAX excludes certain items that management believes affect the comparability of operating results. The most directly comparable GAAP measure is net income (loss), but it is not possible, without unreasonable efforts, to identify the amount or significance of events or transactions that may be included in future GAAP net income (loss) but that management does not believe to be representative of underlying business performance. The company further believes that providing estimates of the amounts that would be required to reconcile forecasted adjusted EBITDAX to forecasted GAAP net income (loss) would imply a degree of precision that may be confusing or misleading to investors. Items excluded from net income (loss) to arrive at adjusted EBITDAX include interest expense, income taxes, depreciation, depletion and amortization expense, and exploration expense as well as one-time items or items whose timing or amount cannot be reasonably estimated.

Reconciliation of Net Income (Loss) to Adjusted EBITDAX (unaudited)

($ in millions)	Successor: Three Months Ended March 31, 2022	Successor: Period from February 10, 2021 through March 31, 2021	Predecessor: Period from January 1, 2021 through February 9, 2021	Non-GAAP Combined: Three Months Ended March 31, 2021
Net income (loss) (GAAP)	**$ (764)**	**$ 295**	**$ 5,383**	**$ 5,678**
Adjustments:				
Interest expense	32	12	11	23
Income tax benefit	(46)	—	(57)	(57)
Depreciation, depletion and amortization	409	122	72	194
Exploration	5	1	2	3
Unrealized (gains) losses on oil and natural gas derivatives	1,538	(113)	369	256
Separation and other termination costs	—	—	22	22
Gains on sales of assets	(279)	(4)	(5)	(9)
Other operating expense (income), net	31	2	(12)	(10)
Reorganization items, net	—	—	(5,569)	(5,569)
Other	(13)	(21)	—	(21)
Adjusted EBITDAX (Non-GAAP)	**$ 913**	**$ 294**	**$ 216**	**$ 510**

Adjusted EBITDAX is not a measure of financial performance under GAAP, and should not be considered as an alternative to, or more meaningful than, net income (loss) prepared in accordance with GAAP. Adjusted EBITDAX excludes certain items that management believes affect the comparability of operating results. The company believes this non-GAAP financial measure is a useful adjunct to cash flow provided by operating activities because: (i) Management uses adjusted EBITDAX to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies. (ii) Adjusted EBITDAX is more comparable to estimates provided by securities analysts. (iii) Items excluded generally are one-time items or items whose timing or amount cannot be reasonably estimated. Accordingly, any guidance provided by the company generally excludes information regarding these types of items. Because adjusted EBITDAX excludes some, but not all, items that affect net income (loss), our calculations of adjusted EBITDAX may not be comparable to similarly titled measures of other companies.

Reconciliations of Adjusted Free Cash Flow and Net Debt

ADJUSTED FREE CASH FLOW

($ in millions)	Successor: Three Months Ended March 31, 2022	Successor: Period from February 10, 2021 through March 31, 2021	Predecessor: Period from January 1, 2021 through February 9, 2021	Non-GAAP Combined: Three Months Ended March 31, 2021
Net cash provided by (used in) operating activities (GAAP)	**$ 853**	**$ 409**	**$ (21)**	**$ 388**
Cash paid for reorganization items, net	—	18	66	84
Cash paid for acquisition costs	23	—	—	—
Capital expenditures	(344)	(77)	(66)	(143)
Adjusted free cash flow (Non-GAAP)	**$ 532**	**$ 350**	**$ (21)**	**$ 329**

NET DEBT

($ in millions)	Successor: March 31, 2022
Total debt (GAAP)	**$ 2,774**
Premiums and issuance costs on debt	(103)
Principal amount of debt	**2,671**
Cash and cash equivalents	(19)
Net debt (Non-GAAP)	**$ 2,652**

Non-GAAP Financial Measures

This document includes non-GAAP financial measures. Such non-GAAP measures should not be considered as an alternative to, or more meaningful than, GAAP measures. The Company's management believes that these measures provide useful information to external users of the Company's consolidated financial statements, such as industry analysts, lenders and ratings agencies. Due to the forward-looking nature of adjusted EBITDAX, net debt, projected free cash flow, free cash flow yield and free cash flow per share used herein, management cannot reliably predict certain of the necessary components of the most directly comparable forward-looking GAAP measures. Accordingly, the Company is unable to present a quantitative reconciliation of such forward-looking non-GAAP financial measures to their most directly comparable forward-looking GAAP financial measures without unreasonable effort. Amounts excluded from these non-GAAP measures in future periods could be significant.

Adjusted EBITDAX: Adjusted EBITDAX is a non-GAAP measure used by management to evaluate the Company's operational trends and performance relative to other oil and natural gas producing companies. Adjusted EBITDAX excludes certain items that management believes affect the comparability of operating results. The most directly comparable GAAP measure is net income (loss). Items excluded from net income (loss) to arrive at adjusted EBITDAX include interest expense, income taxes, depreciation, depletion and amortization expense, and exploration expense as well as one-time items or items whose timing or amount cannot be reasonably estimated.

Net Debt: Net debt is defined as total GAAP debt excluding premiums, discounts, and deferred issuance costs less cash and cash equivalents. Net debt is presented as a widely understood measure of liquidity, but should not be considered as an alternative to, or more meaningful than, total debt presented in accordance with GAAP.

Adjusted Free Cash Flow, Adjusted Free Cash Flow Yield and Adjusted Free Cash Flow Per Share:

- Adjusted free cash flow is defined as net cash provided by operating activities (GAAP), less cash capital expenditures.
- Adjusted free cash flow yield is defined as adjusted free cash flow divided by market capitalization.
- Adjusted free cash flow per share is defined as adjusted free cash flow divided by the Company's outstanding shares of common stock.

Adjusted free cash flow, free cash flow yield and adjusted free cash flow per share are non-GAAP supplemental financial measures used by the Company's management to assess liquidity, including the Company's ability to generate cash flow in excess of its capital requirements and return cash to shareholders. Adjusted free cash flow, adjusted free cash flow yield and adjusted free cash flow per share should not be considered as alternatives to, or more meaningful than, net cash provided by operating activities, or any other measure of liquidity presented in accordance with GAAP.

Pro Forma: Company measures after Vine acquisition, Chief acquisition and Powder River Basin divestiture.