Answering the Call for Affordable, Reliable, Lower Carbon Energy

2Q 2022 EARNINGS / AUGUST 2, 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, returns to shareholders through dividend plans and equity repurchases, portfolio/inventory returns, 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 and equity repurchases, to finance reserve replacement costs and/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 ability to achieve and maintain ESG certifications/goals; 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.

Premium Returns, Inventory and Balance Sheet

Most Compelling Natural Gas Opportunity

STRATEGIC PILLARS	
Superior Capital Returns	**Most efficient operator, returning more cash to shareholders** than any other gas peer in the U.S.
Deep, Attractive Inventory	Premier operator with **>15 years of inventory** **>2,200 gas locations** at $4.00 flat pricing **>100% IRR**
Premier Balance Sheet	Projected at YE'22 **~0.6x net debt-to-EBITDAX ratio**[1]
ESG Excellence	**Achieved Grade "A" MiQ and EO100™ certification** Highest available grade for legacy Marcellus and Haynesville operations

(1) Assumes projections and outlook as of 8/2/22. A non-GAAP measure as defined in the appendix. 6/30/22 net debt balance as a ratio to midpoint of projected 2022 EBITDAX.

2Q'22 Highlights

Continued repurchase program
~$670mm
of $2B authorization used through 7/31

Dividend payable
$2.32
per share in Sept. 2022

Base dividend increased by
10%
to $2.20 per share annually

Adjusted free cash flow(1)
$494mm
FY'22E projection affirmed $2.6B – $2.8B

Adjusted EBITDAX(1)
$1,269mm
FY'22E projection raised to $4.8B – $5.0B

Total dividends payable in '22E
$1.1B – $1.3B

Achieved Grade "A" MiQ and EO100™ certification
Highest available grade
for legacy Haynesville and Marcellus

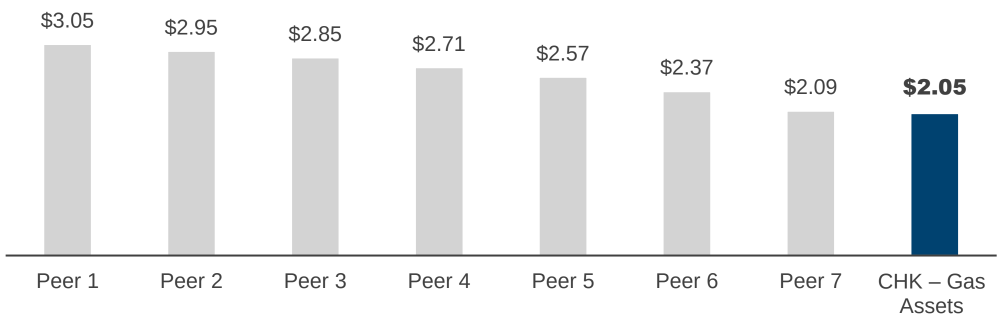
(1) Assumes projections and outlook as of 8/2/22. A non-GAAP measure as defined in the appendix.

Premier Natural Gas Operator

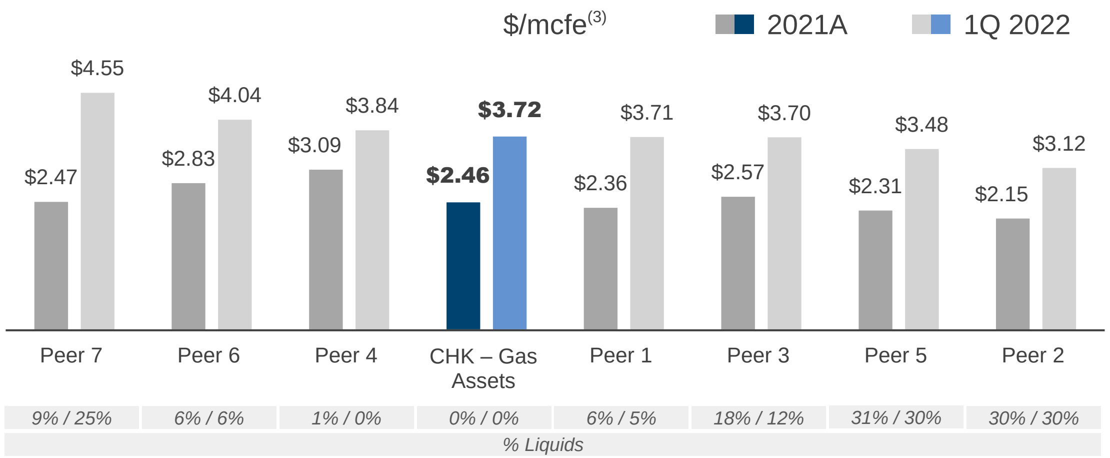
Best Capital Efficiency

2018 – 2021 Average Capex/12-Month Production

$/mcfe(1)



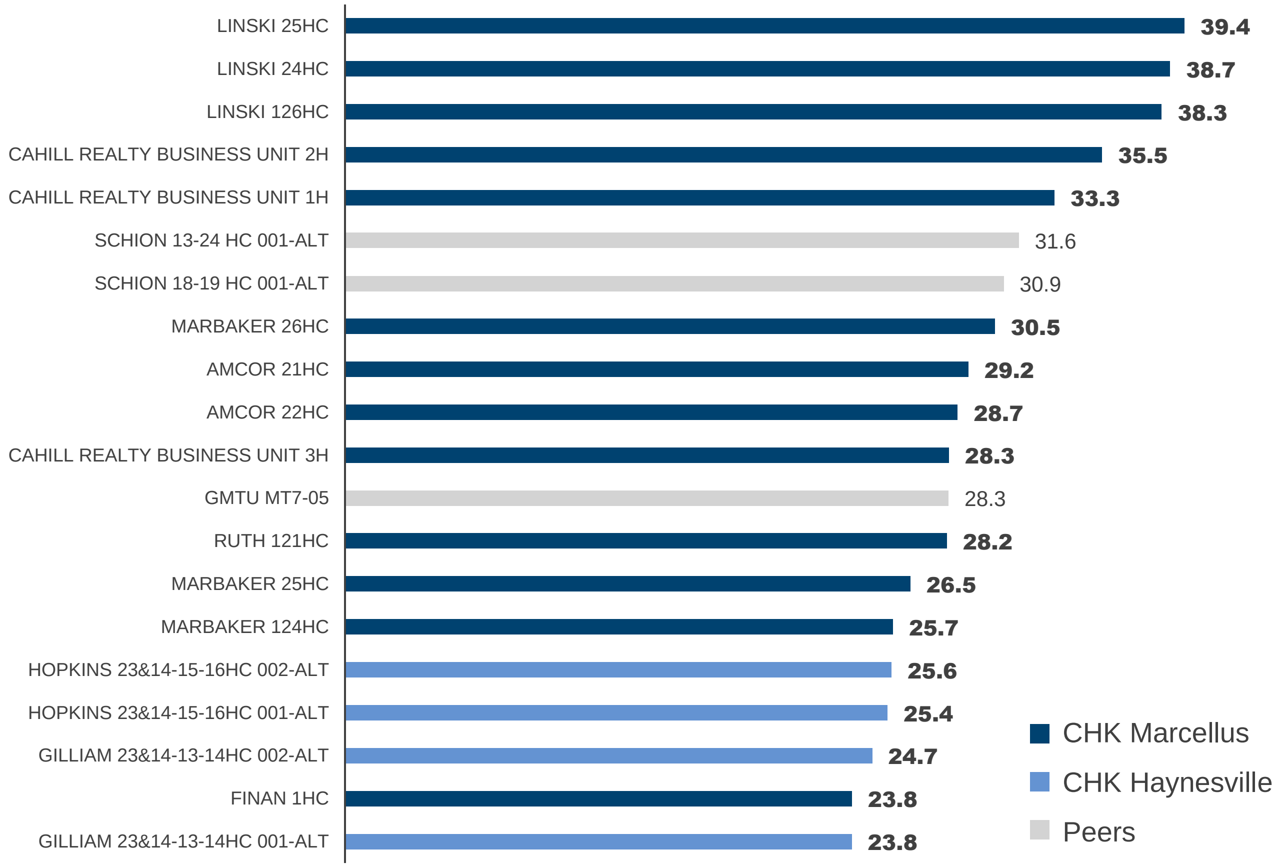
Competitive Unhedged Operating Margin



Chesapeake has 17 of Highest 20 IP90s in North America

2022 Wells – First 3 Month Gas Production

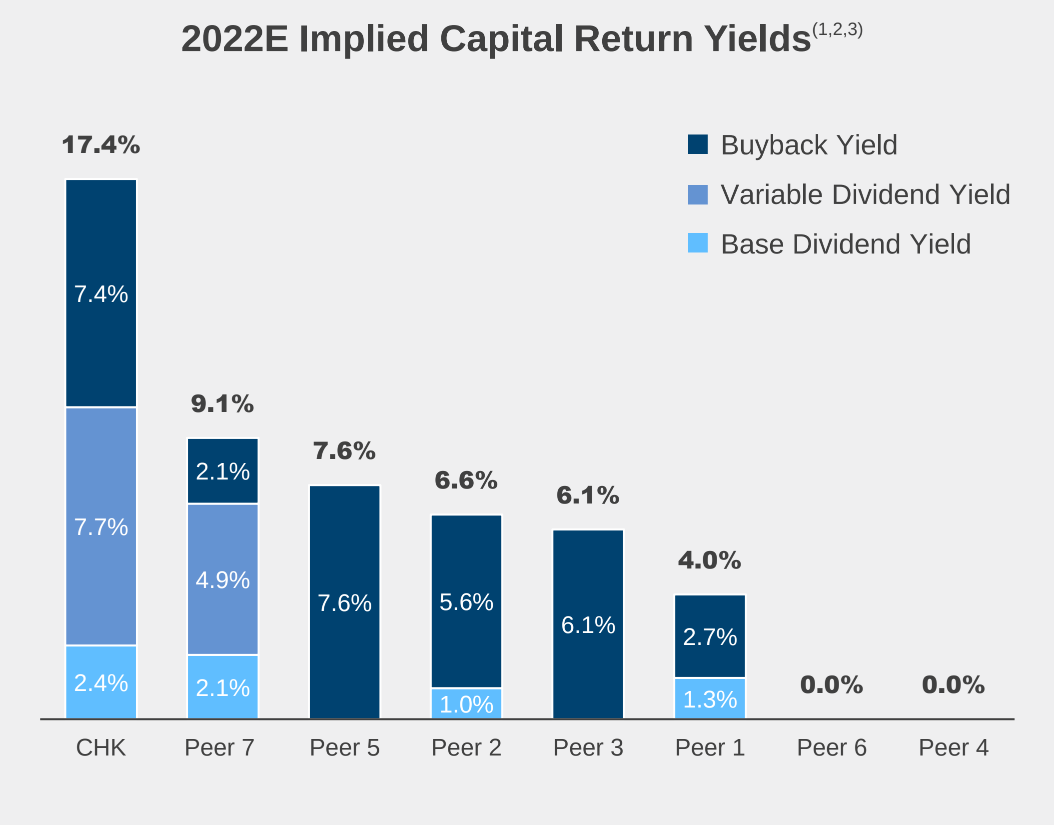
mmcf/d(2)



(1) Source: Enverus; Peer group includes: AR, CNX, CRK, CTRA, EQT, RRC, SWN
(2) Source: Enverus; North American wells with first production date after 1/1/22 and 3 months of production. Well set as of 8/1/2022. Daily rates are 3-month cumulative gas production divided by 90.
(3) Source: Company filings. Margin calculated as unhedged operating income plus DD&A, impairments, exploration and disposal of assets.

Best-in-Class Shareholder Return Program

- **Base dividend increased by ~10% to $2.20 per share annually**
- **$2.32 per share quarterly dividend payable in September**
  - $0.55 base dividend
  - $1.77 variable dividend
- **Anticipate paying $1.1B – $1.3B in total dividends in 2022 (~10% current yield)[1,3]**
  - 3Q'22E projected total dividends paid of $275mm – $285mm
- **Completed 1/3rd of $2B share and warrant repurchase program**
  - 7.6mm common shares purchased through 7/31 at a weighted average price of ~$88 per share for a total of ~$670mm
    - 2.2mm common shares purchased since June 22 buyback increase announcement



(1) Based on consensus estimates as of 7/25 and CHK stock price. Peers include: AR, CNX, CRK, CTRA, EQT, RRC, SWN
(2) CHK assumes $1 billion of common shares repurchased during 2022
(3) Assumes projections and outlook as of 8/2/22.

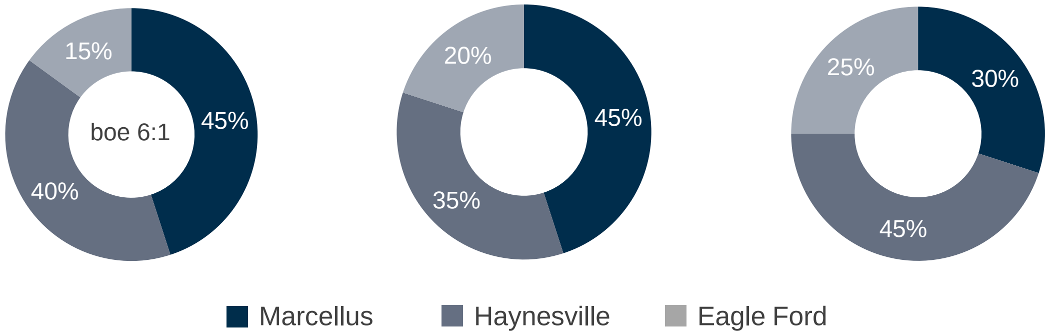
2022 Operating Plan

'22E Activity

2Q'22 Actual and 2022E Projected Results

	2Q'22	3Q'22E	FY'22E
Gas Production (bcf/d)	3.7	3.7 – 3.8	3.6 – 3.7
Oil Production (mbo/d)	50	50 – 54	51 – 56
Total Production (mmcfe/d)	4,125	4,140 – 4,170	4,020 – 4,140
Adj. EBITDAX ($mm)(1)	$1,269	$1,275 – $1,375	$4,800 – $5,000
Total Capex ($mm)(2)	$511	$550 – $600	$1,750 – $1,950
Dividends Paid ($mm)	$298	$275 – $285	$1,100 – $1,300

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



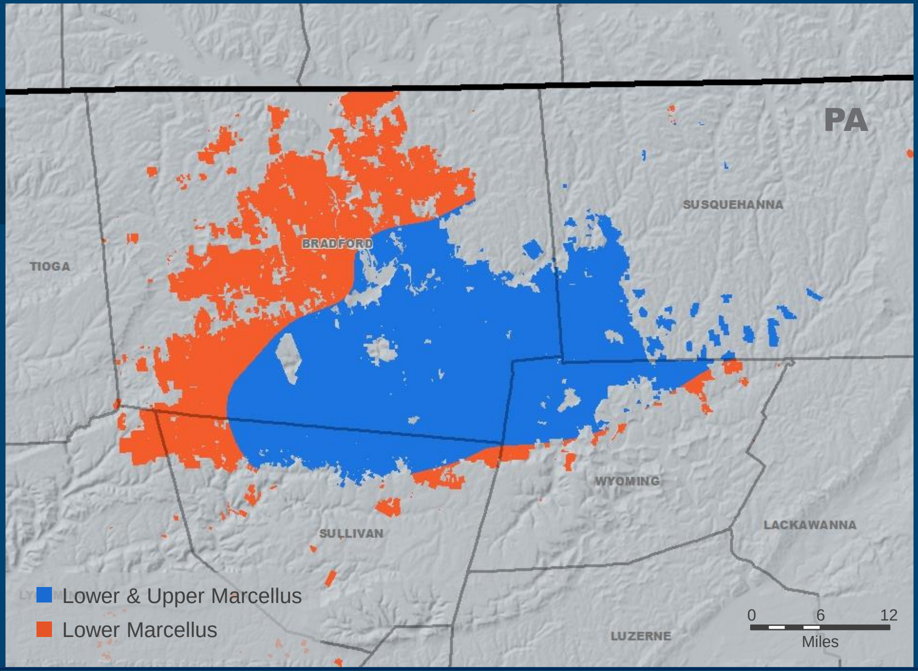
Note: All values assume closing of Chief assets on 3/9/22 and divestiture of Powder River Basin assets on 3/25/22.
(1) Reflects strip prices as of 7/25/22. A non-GAAP measure as defined in the appendix.
(2) Total Capex FY'22E reconciliation included in appendix

Marcellus: Premium Scale, Leading Returns

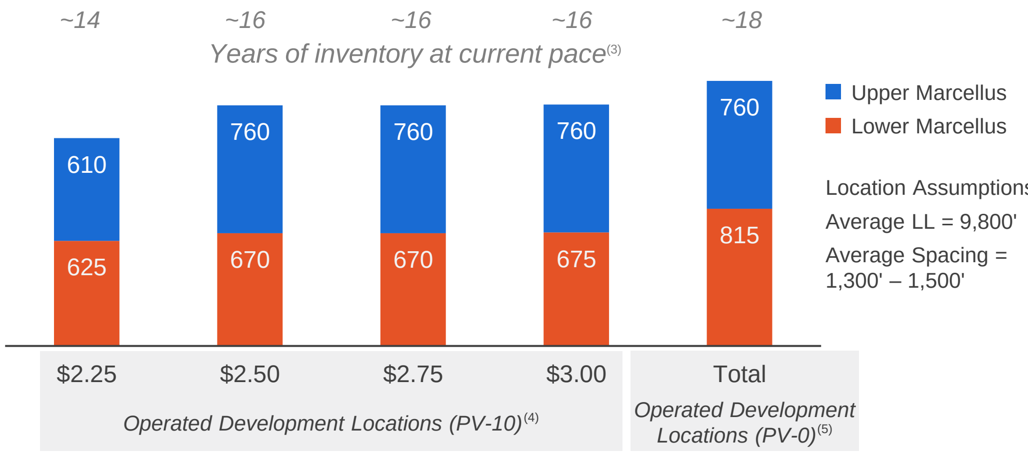
- Basin leading capital efficiency
- ~16 years of drilling using 3 – 5 rigs
- 2022E BU EBITDAX[1,2] \$4.0B – \$4.1B
- Achieved Grade "A" MiQ and EO100™ certification for legacy Marcellus operations – projected to be 100% RSG certified by YE'22
- Chief integration on track, incremental ~80 gross mmcf/d realized through gathering system optimization to date

\$7B

5-year projected FCF[2] *net of allocated hedges, corporate items and taxes*

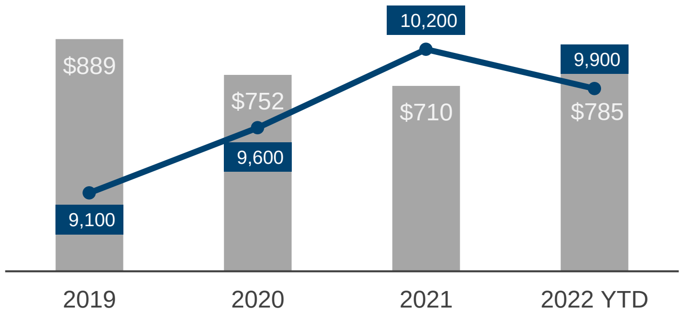


Gross Inventory by Breakeven



Location Assumptions:
Average LL = 9,800'
Average Spacing = 1,300' – 1,500'

Average Cost per Foot and Lateral Length



(1) BU level EBITDAX based on outlook as of 8/2/22 and excludes hedges and corporate items
(2) Adjusted strip deck utilizes NYMEX strip pricing as of 7/25/22 for 2022 (\$7.18 HHUB / \$97 WTI) and 2023 (\$5.92 / \$84), then \$4.00 / \$75 thereafter
(3) Assumes 88 wells per year
(4) 10% IRR at current spacing assumptions, proven development zones
(5) Location counts are based on existing acreage and do not include zones still in early evaluation or exploration wells
Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix

Marcellus: Premium Scale, Leading Returns

Asset Overview	2Q'22	3Q'22E	FY'22E
Net Production (bcf/d)	1.96	1.95 – 2.05	1.9 – 2.0
Wells Drilled	21	23 – 27	85 – 95
Wells TIL'd	31	6 – 10	85 – 95
Average LL (feet)			~11,000
PDP Decline (5 year)			~20%
2022 TIL Decline (1 year)			~60%

Cost Assumptions (net)	2Q'22	3Q'22E	FY'22E
Differential to NYMEX ($/mcf)	($0.71)		($0.50) – ($0.60)
LOE ($/mcf)	$0.11		$0.09 – $0.11
GP&T ($/mcf)	$0.59		$0.60 – $0.70
D&C Capital ($mm)	$127	$110 – $120	$400 – $440
Total Capital ($mm)	$137	$130 – $140	$450 – $525

Marcellus Sales Points

HISTORICAL DEDUCT FROM NYMEX ($)[1]	
TGP 800L	($0.11)
Transco Z4	($0.03)
TETCO M3	($0.30)
TGP Z4	($0.90)
Leidy	($0.83)
Atlantic Sunrise	($0.02)
19% of NYMEX	

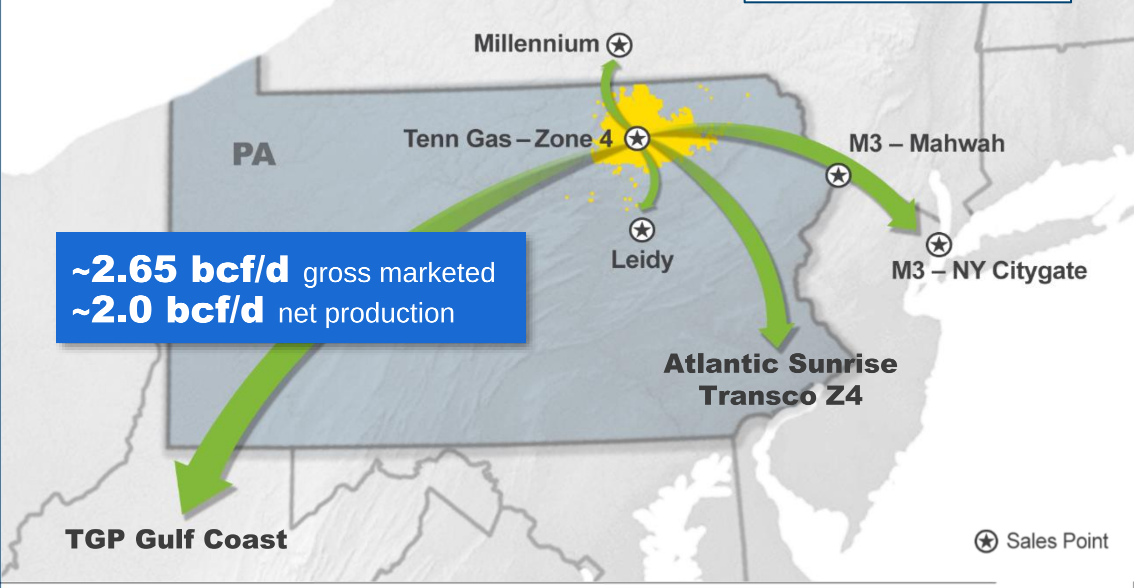
CURRENT DEDUCT FROM NYMEX ($)[1]	
TGP 800L	($0.12)
Transco Z4	$0.73
TETCO M3	$0.66
TGP Z4	($1.15)
Leidy	($1.04)
Atlantic Sunrise	$0.73
7% of NYMEX	

19% of basis hedged for remainder of 2022

MARCELLUS TOTAL PRODUCTION

In Basin: 55%
- TGPZ4: 15%
- Leidy: 35%
- Millennium: 5%

Out of Basin: 45%
- TETCO M3: 18%
- TGP 210/App: 3%
- TGP 800L: 5%
- Transco Z4 (ASR): 8%
- NYMEX/Gulf: 11%



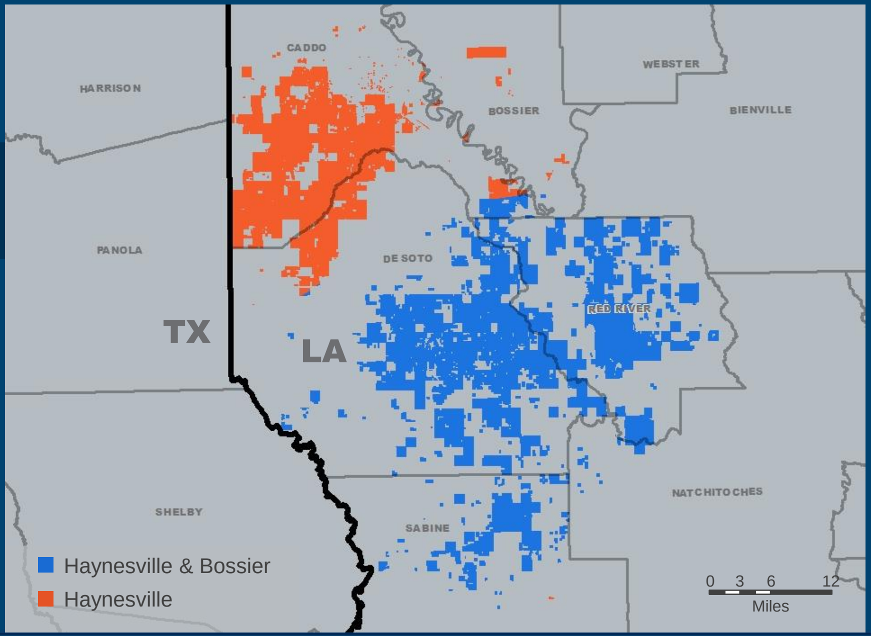
(1) Historical prices based on NYMEX contract settlement prices for Jan 2020 – Dec 2021; current prices based on NYMEX settled and future prices for Jan 2022 – Dec 2023, strip as of 7/25/22, and compared to FY 2022 guided midpoint

Haynesville: Profitable Growth, Advantaged Markets

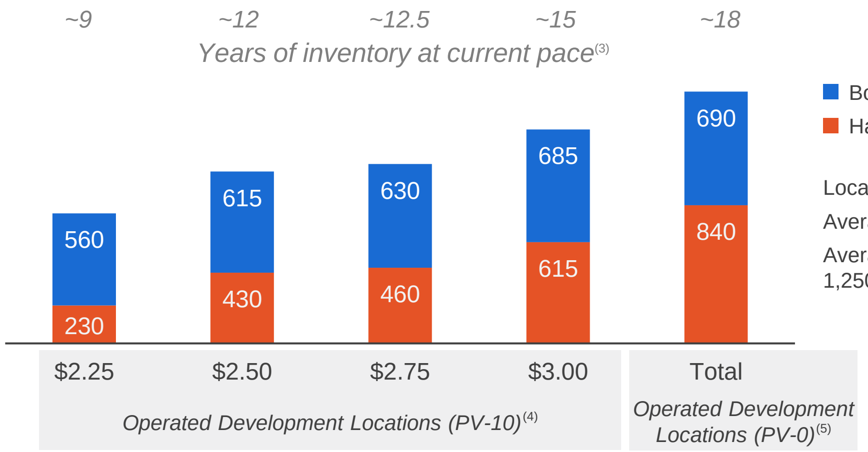
- Basin leading capital efficiency
- ~15 years of drilling using 6 – 9 rigs
- 2022E BU EBITDAX[1,2] $3.3B – $3.4B
- First operator to achieve RSG certification basin-wide
- Vine integration complete, achieved ~$50mm initial annual synergies
- ~15% increase in gas gathering and treatment capacity by 2H’23
- Entered into gas supply agreement with Golden Pass LNG facility

$4B

5-year projected FCF[2] *net of allocated hedges, corporate items and taxes*

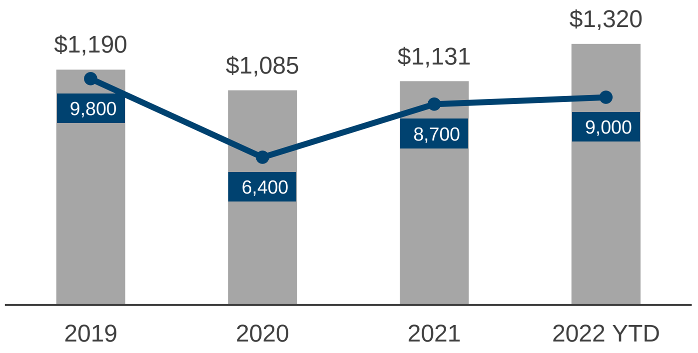


Gross Inventory by Breakeven



Location Assumptions:
Average LL = 7,500'
Average Spacing = 1,250' – 1,750'

Average Cost per Foot and Lateral Length



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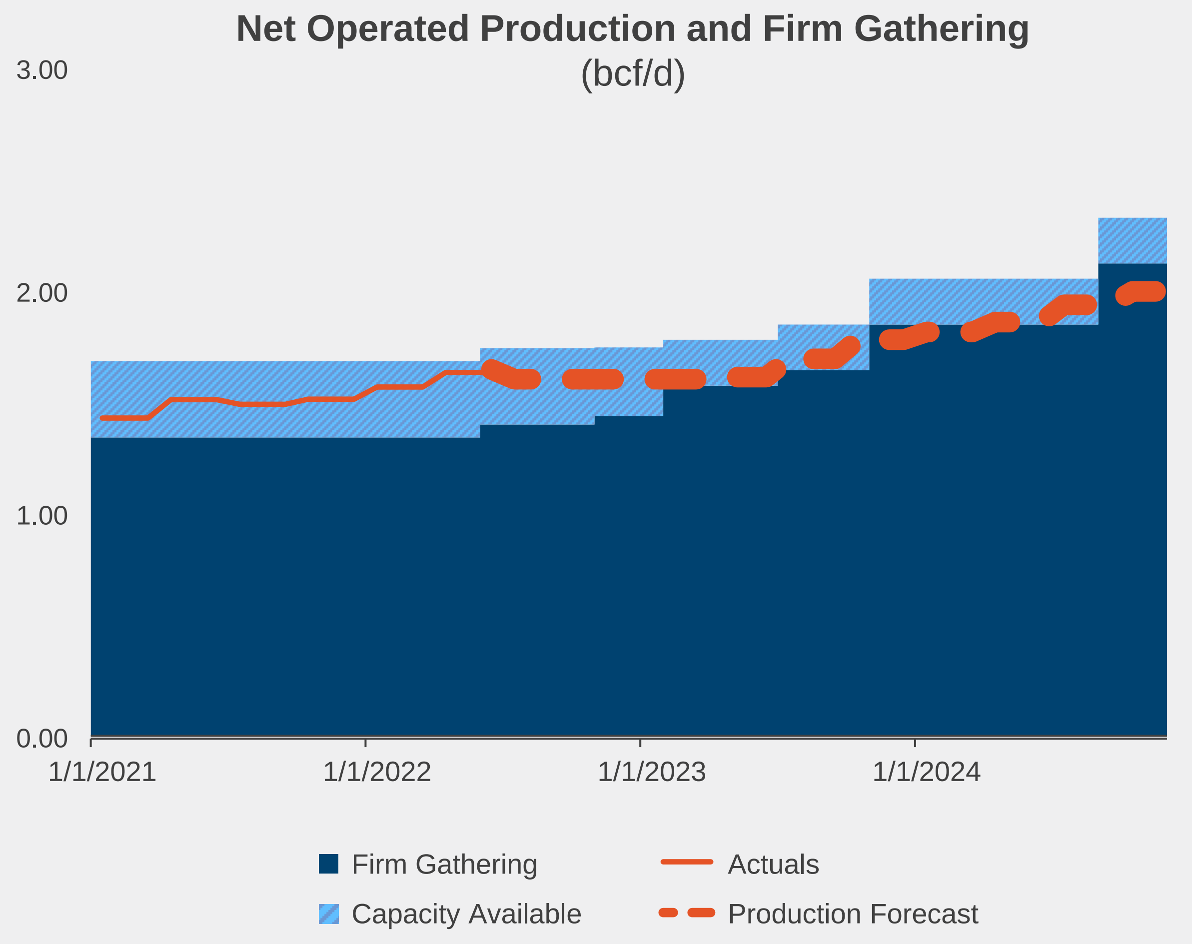
(3) Assumes 88 wells per year
(4) 10% IRR at current spacing assumptions, proven development zones
(5) Location counts are based on existing acreage and do not include zones still in early evaluation or exploration wells
Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix

Haynesville: Poised for Growth

- **Moving from maintenance capital of ~6 rigs to growth with 7 – 8 rigs**
  - 7th rig added by YE'22
- **Contracting gathering and treating capacity expansions to facilitate growth**
- **2023 exit rate increases 5% – 7% from 2022 exit rate**
- **Adding favorable downstream takeaway**
  - Gas supply agreement with Golden Pass LNG facility
  - Taking advantage of competitive transportation market to negotiate long-term takeaway solutions



Haynesville: Profitable Growth, Advantaged Markets

Asset Overview	2Q'22	3Q'22E	FY'22E
Net Production (bcf/d)	1.64	1.55 – 1.65	1.6 – 1.7
Wells Drilled	17	15 – 20	65 – 75
Wells TIL'd	19	15 – 20	65 – 75
Average LL (feet)			~9,000
PDP Decline (5 year)			~30%
2022 TIL Decline (1 year)			~65%

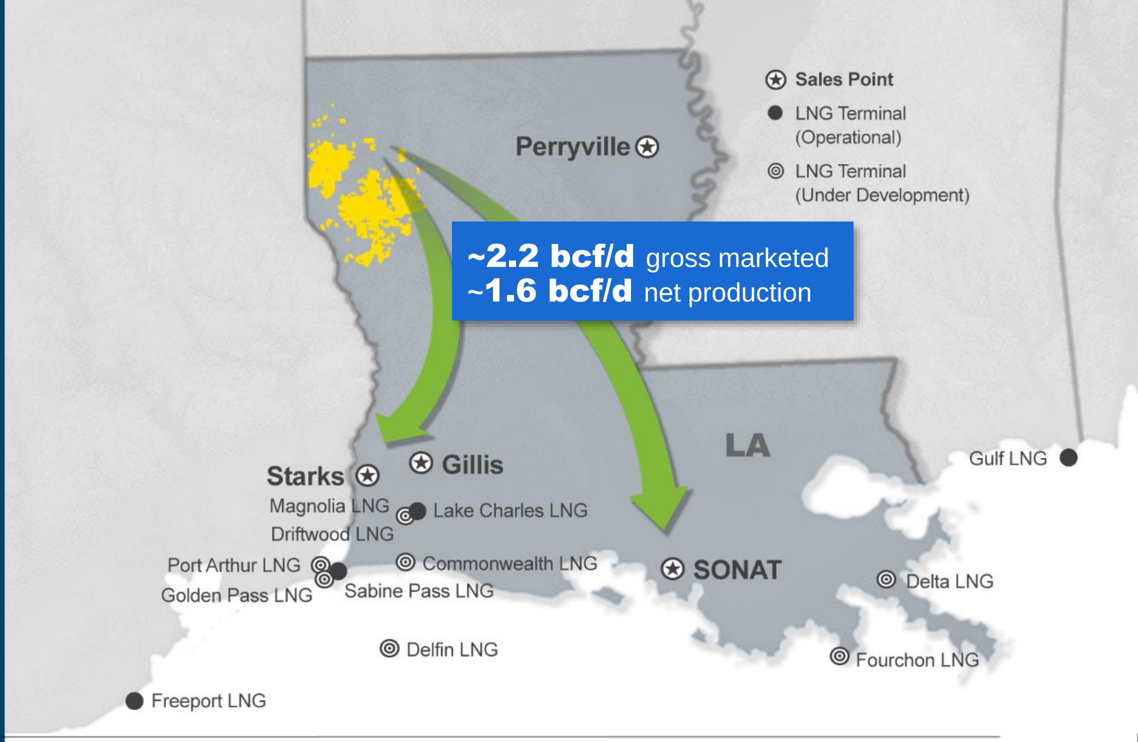
Cost Assumptions (net)	2Q'22	3Q'22E	FY'22E
Basis Differential to NYMEX ($/mcf)	($0.40)		($0.35) – ($0.45)
BTU Factor	977		970 – 980
LOE ($/mcf)	$0.26		$0.25 – $0.35
GP&T ($/mcf)	$0.57		$0.45 – $0.55
D&C Capital ($mm)	$197	$220 – $230	$750 – $800
Total Capital ($mm)	$216	$235 – $245	$825 – $900

- Chesapeake expects to benefit from pipeline solutions reducing basis differential to historical levels of $0.20 – $0.25 with anticipated in-service dates between 2023 – 2025

Haynesville Sales Points

HISTORICAL DEDUCT FROM NYMEX ($)[1]		CURRENT DEDUCT FROM NYMEX ($)[1]		HAYNESVILLE TOTAL PRODUCTION
CGML	($0.28)	CGML	($0.41)	CGML: 60%
TGT	($0.20)	TGT	($0.30)	TGT: 25%
10% of NYMEX		8% of NYMEX		Other Gulf Coast: 15%

46% of basis hedged for remainder of 2022



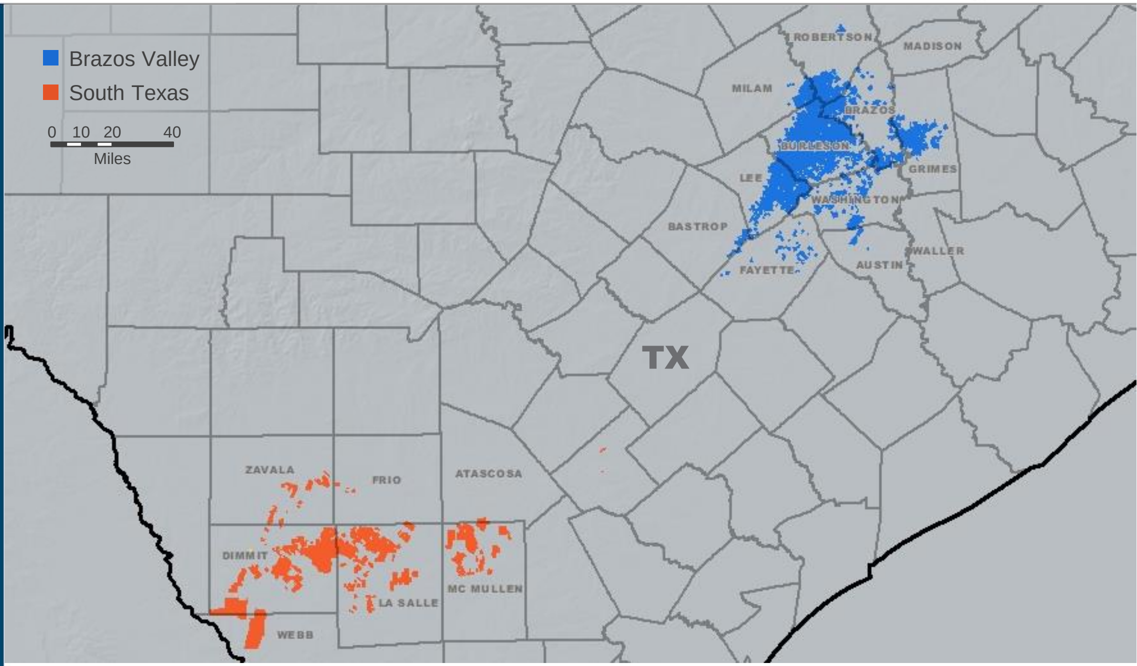
(1) Historical prices based on NYMEX contract settlement prices for Jan 2020 – Dec 2021; current prices based on NYMEX settled and future prices for Jan 2022 – Dec 2023, strip as of 7/25/22, and compared to FY 2022 guided midpoint

Eagle Ford: Superior Margins, Sustainable Free Cash Flow

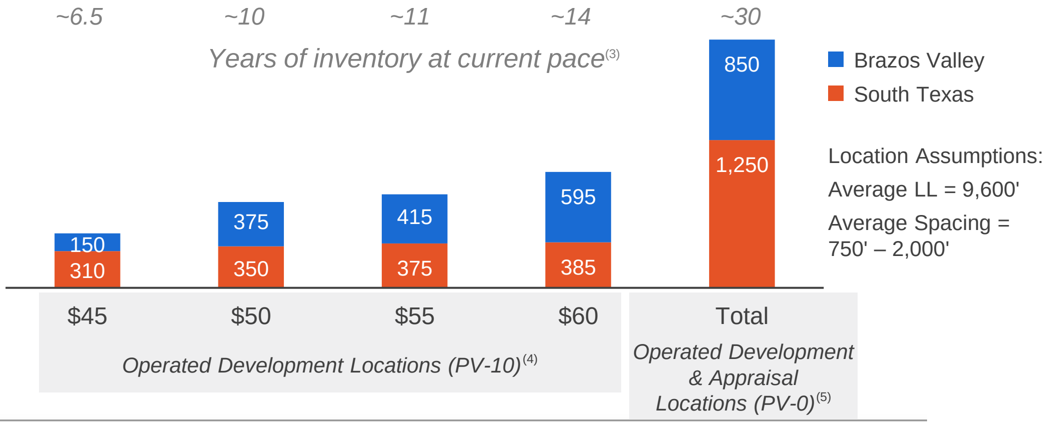
- ~14 years of drilling using 2 – 3 rigs
- 2022E BU EBITDAX[1,2] $1.7B – $1.9B
- Emerging Austin Chalk potential, ~10 wells in 2022 program
- Gas MVC shortfall projected to decline by 50% YoY

Asset Overview	2Q’22	3Q’22E	FY’22E
Net Production (mboe/d)	88	85 – 95	90 – 100
Wells Drilled	25	20 – 25	50 – 65
Wells TIL’d	7	15 – 20	50 – 65
Average LL (feet)			~10,500
PDP Decline (5 year)			~15%
2022 TIL Decline (1 year)			~70%

Cost Assumptions (net)	2Q’22	3Q’22E	FY’22E
Differential to NYMEX ($/bbl)	$0.71		$1.20 – $1.60
LOE ($/boe)	$7.50		$6.50 – $6.75
GP&T ($/boe)	$10.50		$9.50 – $10.50
D&C Capital ($mm)	$135	$165 – $175	$375 – $415
Total Capital ($mm)	$158	$190 – $200	$450 – $500



Gross Inventory by Breakeven



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(2) Adjusted strip deck utilizes NYMEX strip pricing as of 7/25/22 for 2022 ($7.18 HHUB / $97 WTI)
(3) Assumes 70 wells per year
(4) 10% IRR at current spacing assumptions, proven development zones
(5) Location counts are based on existing acreage. Only total counts include zones still in early evaluation or exploration wells.
Note: EBITDAX is a non-GAAP measures which is defined in the appendix

Delivering ESG Excellence

ENVIRONMENTAL

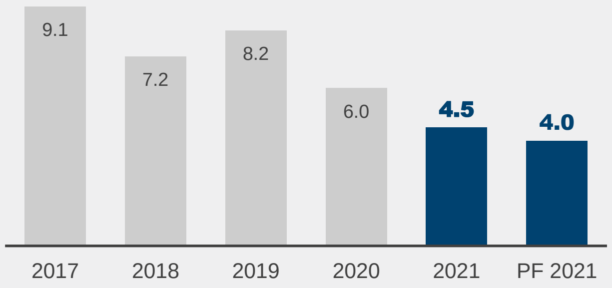
Achieved Grade "A" MiQ and EO100™ certification for legacy Haynesville and Marcellus operations

>2,000 continuous methane monitoring devices operating today

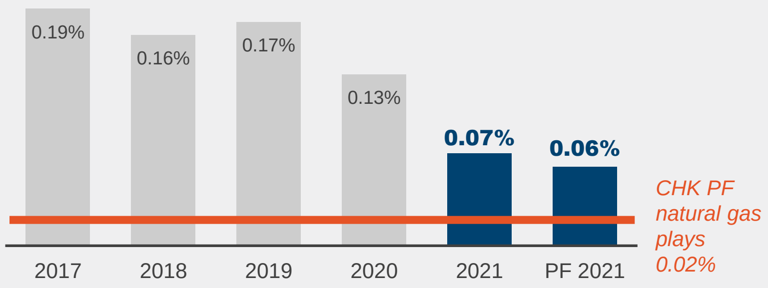
Zero routine flaring on wells completed in 2021 and beyond, enterprise by 2025

Net zero direct GHG emissions by 2035

CHK GHG Emissions Intensity
metric tons CO_2e/gross mboe produced



CHK Methane Intensity
volume methane emissions/volume gross natural gas produced



SOCIAL

Committed to Answering the Call for Affordable, Reliable, Lower Carbon Energy

Culture of transparency, contribution from all employees and respect for diverse perspectives through our diversity, equity and inclusion (DEI) efforts

Launched Supplier Diversity Program in 2021

Investing in systems and processes to enhance royalty owner engagement

GOVERNANCE

Fresh executive leadership with all Board members having less than two years of tenure

Established an Environment and Social Governance Committee dedicated to sustainability strategy and oversight

Compensation for all employees directly tied to company performance, shareholder returns and ESG excellence

Failure to meet ESG performance targets caps bonus payout for all other metrics

Most Compelling Natural Gas Opportunity

Superior Capital Returns	✓ Unwavering commitment to returning cash flow to shareholders
Deep, Attractive Inventory	✓ Capital efficient assets that sustainably generate returns
Premier Balance Sheet	✓ Resilient credit metrics that de-risk equity returns through commodity price cycles
ESG Excellence	✓ Leading emissions profile, commitment to social initiatives and shareholder-aligned compensation incentives

Appendix

CHESAPEAKE ENERGY

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.

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.

Free Cash Flow, Free Cash Flow Yield and 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.

Glossary

BE: Breakeven – the minimum price at which cumulative cash flows are zero

BU: Business Unit

CFFO: Cash flow from Operations

CROCI: Cash Returned on Capital Invested is the 3-year EBITDA – Interest Expense – G&A / Total Net D&C and Non-D&C Capital

D&C: Drilling and Completion expense

ESG: Environmental, Social, Governance

FCF: Free Cash Flow

G&A: General and Administrative expense

G&G: Geological and Geophysical expense

GHG: Greenhouse Gas

GP&T: Gathering, Processing and Transport expense

IP90: Initial production rate for the first 90 days

IRR: Internal Rate of Return is the discount rate at which cumulative cash flows equal to zero

LHC: Leasehold Capital expense

LL: Lateral length is the length from the point at which a wellbore enters the target zone to the terminus point of the wellbore

MVC: Minimum Volume Commitment

NAV: Net Asset Value

NPV: Net Present Value

NRI: Net revenue interest is a share of production after all burdens, such as royalty and overriding royalty, have been deducted from the working interest

PDP: Proved Developed Producing – Reserve classification for a producing well

PIR: Profit Investment Ratio = (PV-10 less capex) / total net capital

PP&E: Property, Plant, and Equipment expense

PV-0: Present Value at a 0% discount rate

PV-10: Present Value at a 10% discount rate

RSG: Responsibly Sourced Gas

SPUD: To start the well drilling process

TIL: Turn-In-Line; a well turned to sales

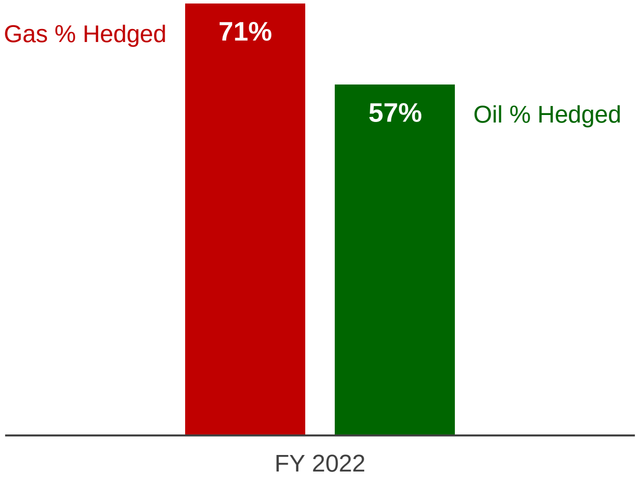
UAC: Upper Austin Chalk

WI: Working Interest is a percentage of ownership in an oil and gas lease granting its owner the right to explore, drill and produce hydrocarbons from a tract of property

WPS: Wells Per Section

Hedging Program Reduces Risk, Protects Returns

As of 7/29/2022



DOWNSIDE PROTECTION LEVELS	RMDR 2022[1]	2023
Gas, $/mcf	$2.91 – $3.43	$3.14 – $4.53
Oil, $/bbl	$45.37	$64.54 – $75.09

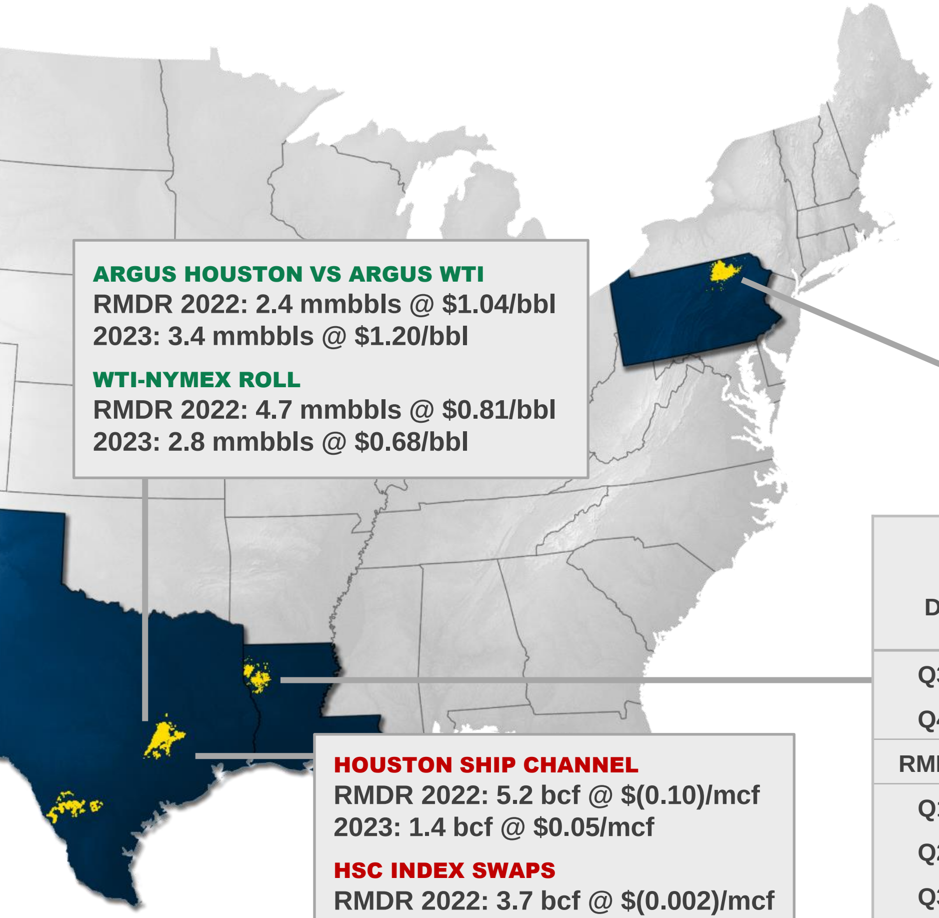
	NATURAL GAS														OIL				
	SWAPS		SWAPTIONS		COLLARS			THREE-WAY COLLARS				CALLS		SWAPS		COLLARS		
Date	Volume *bcf*	Price *$/mcf*	Volume *bcf*	Price *$/mcf*	Volume *bcf*	Bought Put *$/mcf*	Sold Call *$/mcf*	Volume *bcf*	Sold Put *$/mcf*	Bought Put *$/mcf*	Sold Call *$/mcf*	Volume *bcf*	Sold Call *$/mcf*	Volume *mmbbl*	Price *$/bbl*	Volume *mmbbl*	Bought Put *$/bbl*	Sold Call *$/bbl*
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	**251.3**	**2.61**	**-**	**-**	**213.9**	**3.25**	**4.40**	**12.9**	**2.41**	**2.90**	**3.43**	**-**	**-**	**5.3**	**45.37**	**-**	**-**	**-**
Q1 2023	114.3	2.64	1.8	2.88	55.7	3.48	6.32	0.9	2.50	3.40	3.79	18.0	3.29	1.9	47.17	0.7	76.09	91.21
Q2 2023	28.7	2.73	1.8	2.88	119.8	3.39	5.47	0.9	2.50	3.40	3.79	-	-	-	-	2.2	68.45	82.72
Q3 2023	27.2	2.75	1.8	2.88	121.2	3.39	5.47	0.9	2.50	3.40	3.79	-	-	-	-	1.9	69.12	82.23
Q4 2023	33.3	2.69	1.8	2.88	96.2	3.31	5.47	0.9	2.50	3.40	3.79	-	-	-	-	1.4	70.63	84.25
FY 2023	**203.5**	**2.67**	**7.3**	**2.88**	**392.9**	**3.38**	**5.59**	**3.7**	**2.50**	**3.40**	**3.79**	**18.0**	**3.29**	**1.9**	**47.17**	**6.2**	**69.99**	**83.86**

Note: Hedged volume and price reflect positions as of 7/29/22
(1) RMDR 2022 includes 3Q'22 – 4Q'22

Hedged Basis Protection

As of 7/29/2022

- 19% of Marcellus and 46% of Haynesville basis hedged for the remainder of 2022
- Since 6/22/2022, CHK has added basis protection for:
  - 13.3 bcf of 3Q’22 – 4Q’22 gas at an average differential to NYMEX of $(0.67)
  - 8.1 bcf of 2023 gas at $(0.63)



ARGUS HOUSTON VS ARGUS WTI
RMDR 2022: 2.4 mmbbls @ $1.04/bbl
2023: 3.4 mmbbls @ $1.20/bbl

WTI-NYMEX ROLL
RMDR 2022: 4.7 mmbbls @ $0.81/bbl
2023: 2.8 mmbbls @ $0.68/bbl

HOUSTON SHIP CHANNEL
RMDR 2022: 5.2 bcf @ $(0.10)/mcf
2023: 1.4 bcf @ $0.05/mcf

HSC INDEX SWAPS
RMDR 2022: 3.7 bcf @ $(0.002)/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
Q3 2022	12.0	(0.80)	4.5	(1.24)	26.6	(1.16)	60.2	(0.47)	15.6	(0.28)	11.4	0.79
Q4 2022	8.6	0.68	2.8	(1.08)	13.8	(1.04)	59.4	(0.40)	9.8	(0.23)	9.9	0.77
RMDR '22	**20.6**	**(0.18)**	**7.3**	**(1.18)**	**40.4**	**(1.12)**	**119.6**	**(0.43)**	**25.5**	**(0.26)**	**21.3**	**0.78**
Q1 2023	6.8	1.99	4.2	(1.13)	9.5	(0.92)	38.3	(0.27)	6.8	(0.17)	6.8	0.76
Q2 2023	3.6	(0.86)	2.3	(1.33)	3.6	(1.17)	25.5	(0.30)	3.0	(0.25)	6.8	0.76
Q3 2023	3.7	(0.86)	2.3	(1.33)	3.7	(1.17)	25.8	(0.30)	3.0	(0.25)	6.9	0.76
Q4 2023	3.7	0.54	3.8	(1.12)	3.7	(1.09)	22.9	(0.27)	2.4	(0.20)	2.9	0.76
FY 2023	**17.8**	**0.51**	**12.6**	**(1.20)**	**20.5**	**(1.04)**	**112.4**	**(0.28)**	**15.1**	**(0.20)**	**23.4**	**0.76**

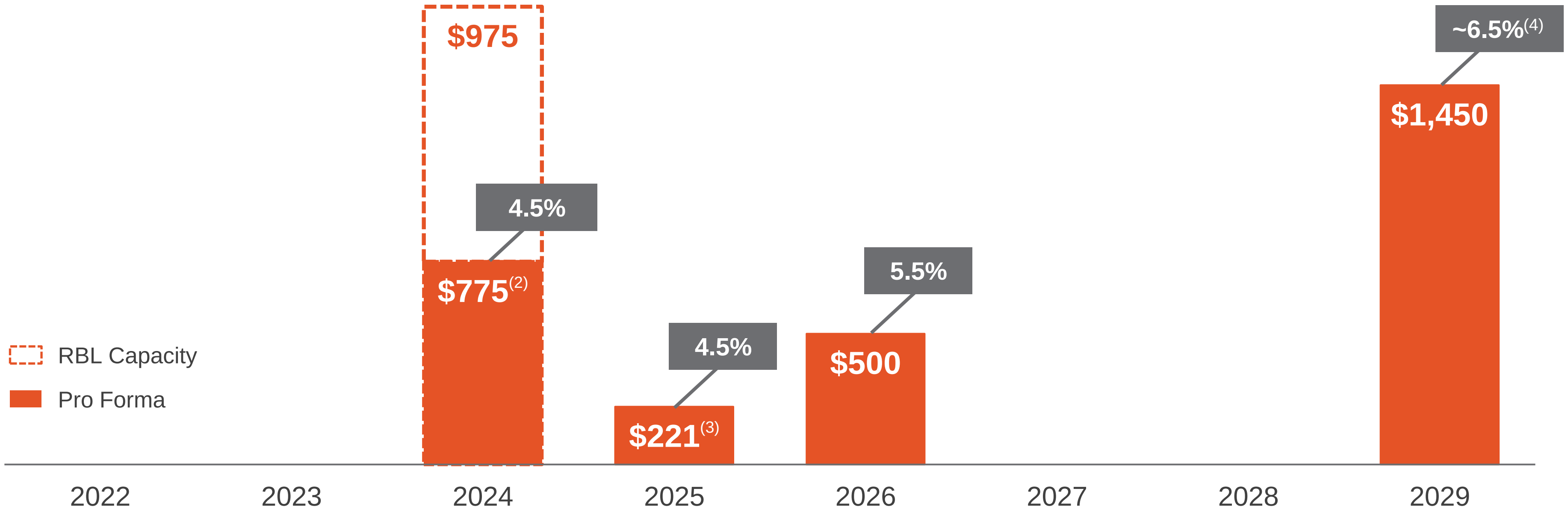
(1) TETCO M3 transport spread vs. TGP Z4 300L

Pro Forma Maturity Profile

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 6/30/22 over midpoint of 2022 Outlook
(2) Revolver balance as of 6/30/22
(3) Represents $221mm of CA-CIB and Natixis Tranche B
(4) $500mm at 5.875% and $950mm at 6.75%

Management's Outlook as of August 2, 2022

	2022 Projections
Total production:	
Oil – mbbls per day	51 – 56
NGL – mbbls per day	15 – 18
Natural gas – mmcf per day	3,600 – 3,680
Total daily rate – mmcfe per day	4,020 – 4,140
Estimated basis to NYMEX prices, based on 7/25/22 strip prices:	
Oil – $/bbl	***$1.20 – $1.60***
Natural gas – $/mcf	($0.45) – ($0.55)
NGL – realizations as a % of WTI	40% – 45%
Operating costs per mcfe of projected production:	
Production expense	$0.29 – $0.33
Gathering, processing and transportation expenses	***$0.70 – $0.80***
Oil – $/bbl	$2.80 – $3.00
Natural Gas – $/mcf	***$0.75 – $0.85***
Severance and ad valorem taxes	$0.16 – $0.18
General and administrative(1)	$0.08 – $0.11
Depreciation, depletion and amortization expense	$1.17 – $1.33
Marketing net margin and other ($ in millions)	$25 – $50
Interest expense ($ in millions)	$125 – $135
Cash taxes ($ in millions)	$225 – $275
Cash taxes (as a percent of income before income taxes)	***6% – 9%***
Adjusted EBITDAX, based on 7/25/22 strip prices ($ in millions)(2)	***$4,800 – $5,000***
Total capital expenditures ($ in millions)	***$1,750 – $1,950***
Marcellus D&C	***$400 – $440***
Haynesville D&C	***$750 – $800***
Eagle Ford D&C	***$375 – $415***
Powder River Basin D&C	$25
Non-D&C Field (workover, infrastructure and leasehold)	***$115 – $165***
Non-D&C Corporate (PP&E, G&G, capitalized interest and G&A)	***$85 – $105***

(1) Includes ~$0.01/mcfe 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 June 30, 2022	Successor Three Months Ended June 30, 2021
Net income (loss) (GAAP)	**$ 1,237**	**$ (439)**
Adjustments:		
Interest expense	36	18
Income tax expense	77	—
Depreciation, depletion and amortization	451	229
Exploration	7	1
Unrealized (gains) losses on oil and natural gas derivatives	(532)	617
Separation and other termination costs	—	11
Gains on sales of assets	(21)	(2)
Other operating expense (income), net	16	(4)
Impairments	—	1
Other	(2)	(3)
Adjusted EBITDAX (Non-GAAP)	**$ 1,269**	**$ 429**

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

	Successor	
	Three Months Ended June 30, 2022	Three Months Ended June 30, 2021
($ in millions)		
Net cash provided by operating activities (GAAP)	**$ 909**	**$ 394**
Cash paid for reorganization items, net	—	47
Cash capital expenditures	(415)	(149)
Adjusted free cash flow (Non-GAAP)	**$ 494**	**$ 292**

NET DEBT

	Successor
	June 30, 2022
($ in millions)	
Total debt (GAAP)	**$ 3,046**
Premiums and issuance costs on debt	(100)
Principal amount of debt	**2,946**
Cash and cash equivalents	(17)
Net debt (Non-GAAP)	**$ 2,929**