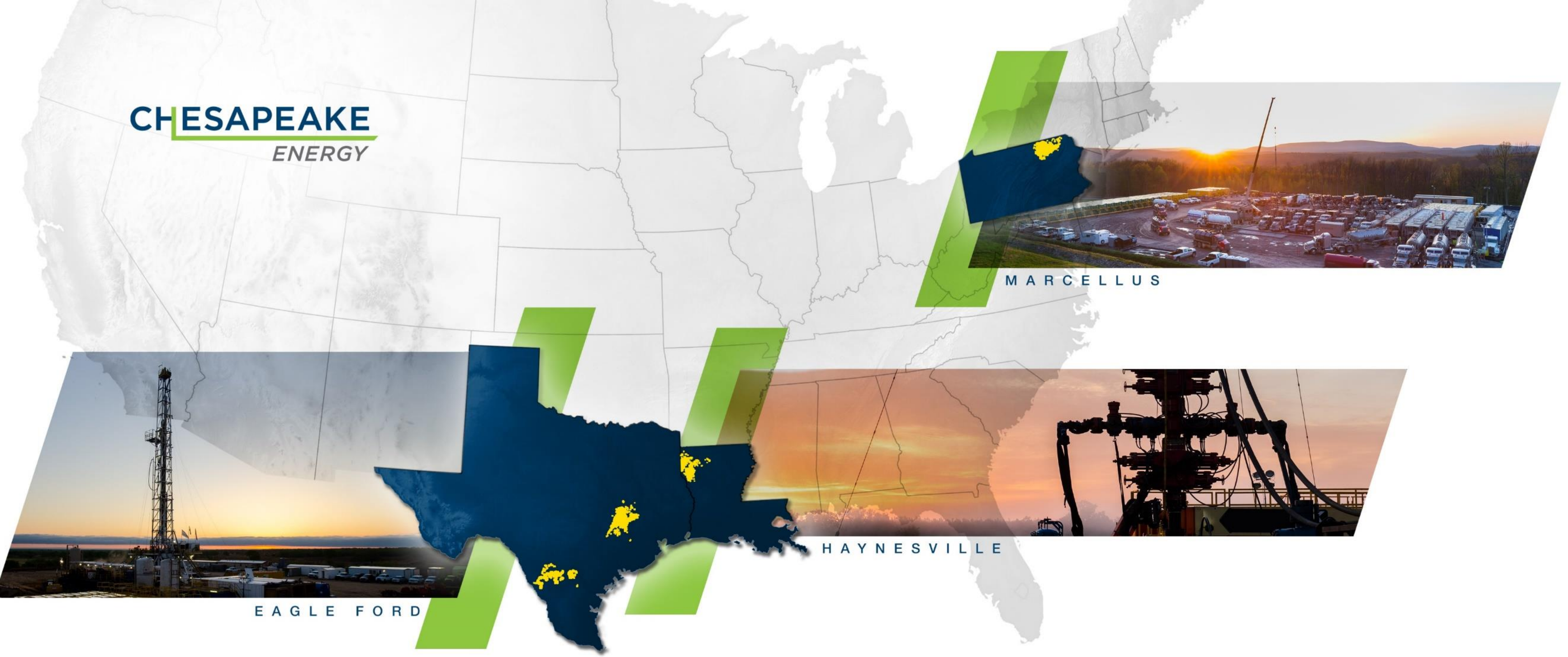
CHESAPEAKE ENERGY



Answering the Call for Affordable, Reliable, Lower Carbon Energy

J.P. MORGAN ENERGY, POWER & RENEWABLES CONFERENCE / JUNE 22, 2022

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, 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.

CHK Today: The Most Compelling Investment in Energy Space

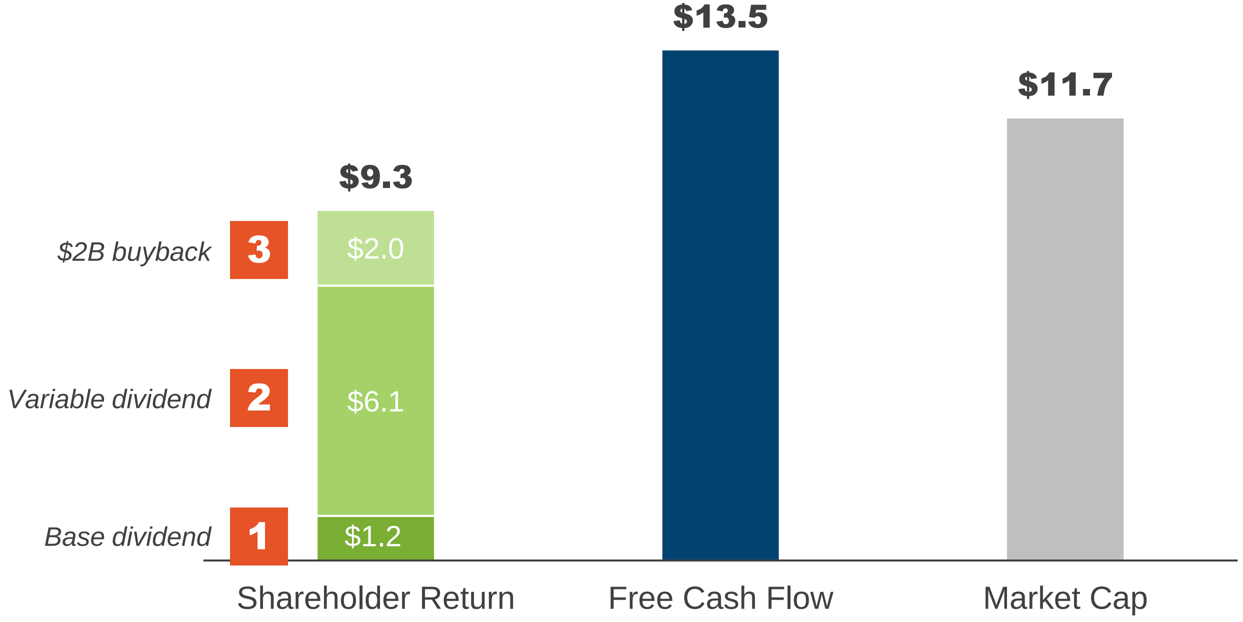
STRATEGIC PILLARS	WHAT TO EXPECT		
Superior Capital Returns	*Next five years:* **~$14B of FCF** at the adj. strip(1) representing ~115% of market cap(2)	*Next five years:* **~$9B returned to shareholders** through dividends and **$2B buyback** at the adj. strip(1)	
Deep, Attractive Inventory	Premier operator with **>15 years** of inventory	**>2,500 locations** at $4.00/$75 flat pricing **>100% IRR**	Portfolio resilient to prices, bolstered through **highly accretive transactions**
Premier Balance Sheet	Committed to maintaining net debt-to-EBITDAX ratio **<1.0x** down to $2.50/$50		
ESG Excellence	**Clear emissions reduction targets** linked to compensation for all employees		

Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix
(1) Adjusted strip deck utilizes NYMEX strip pricing as of 6/17/2022 for 2022 ($6.49 HHUB / $102 WTI) and 2023 ($5.49 / $91), then $4.00 / $75 thereafter
(2) Based on $80.28 stock price as of 6/17/2022 and fully diluted shares

Unwavering Commitment to Delivering Capital Returns

1	**Base Dividend**	Annual $2.00 per share, resilient to downside scenarios
2	**Variable Dividend**	50% of post base dividend FCF
3	**Equity Repurchases**	**$2.0B** program authorized by 2023E
4	**Maintain Balance Sheet Strength**	Maintain net debt-to-EBITDAX of <1.0x down to $2.50/$50

5-Year Plan
2022E – 2026E, $ in billions(1,2)



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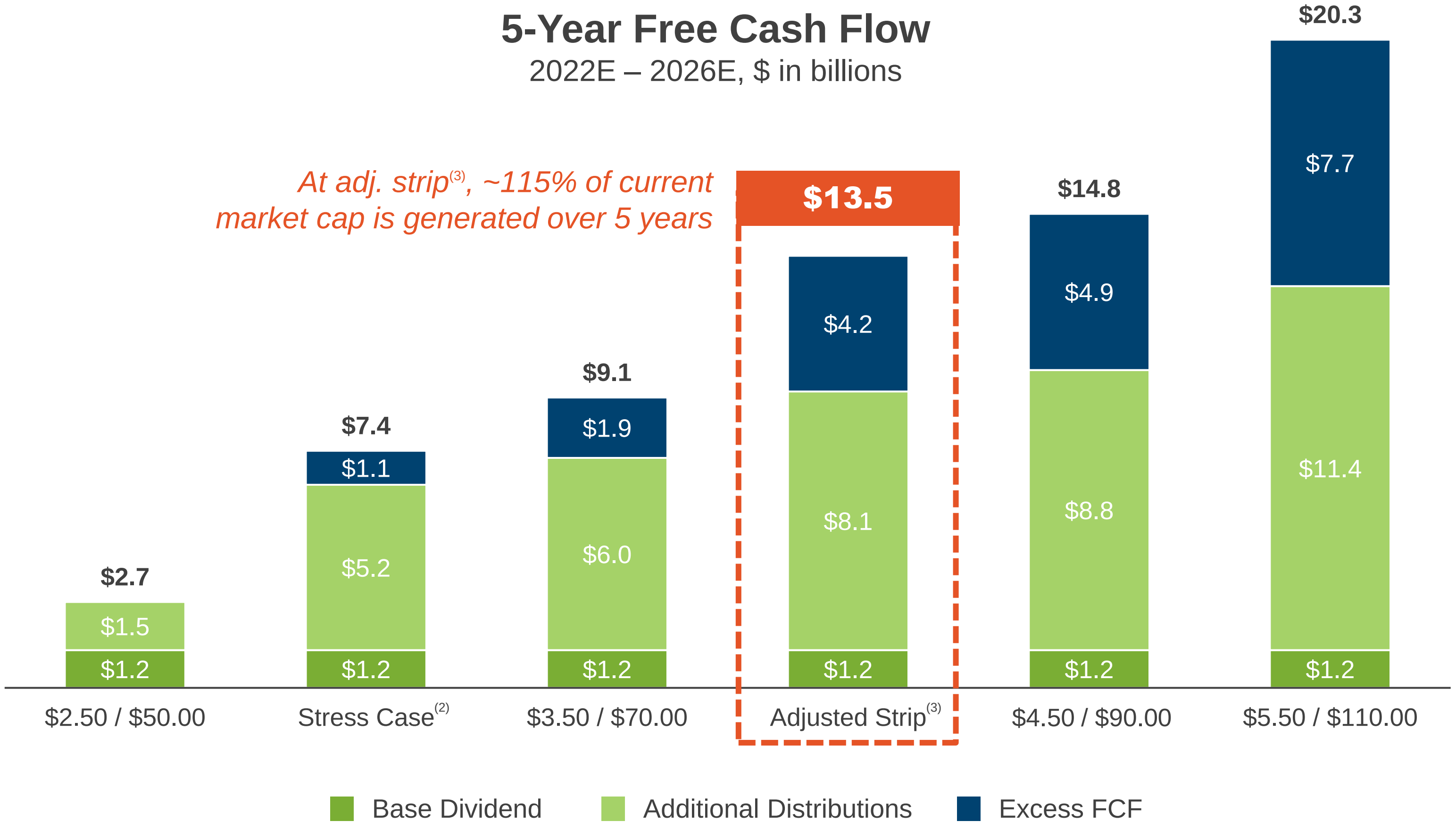
(2) Based on $80.28 stock price as of 6/17/2022 and fully diluted shares

Resilient Returns to Shareholders with Significant Upside

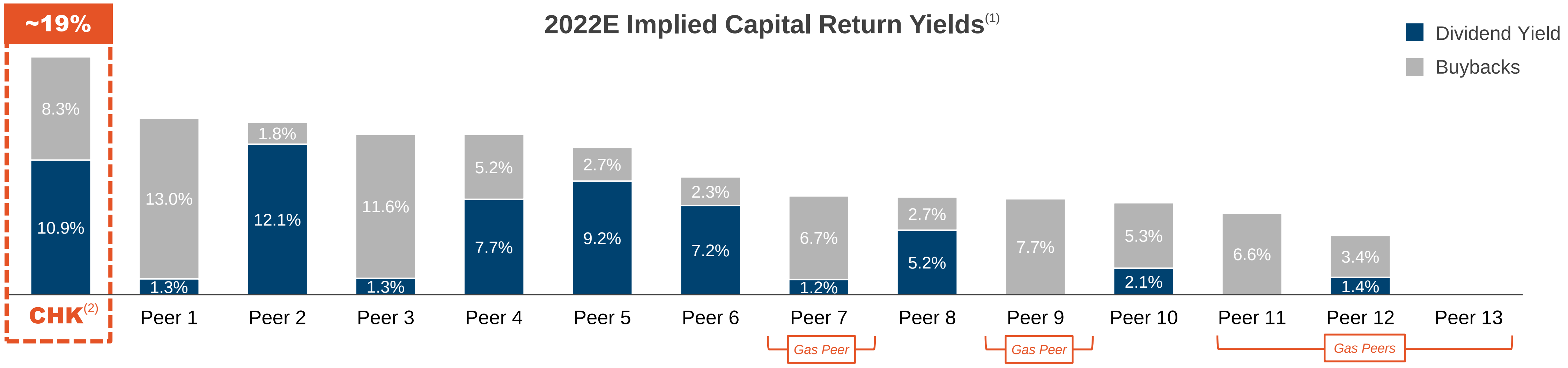
- Sustainable FCF through commodity price cycles
- Base dividend breakeven of ~$2.15/mcf
- Balance sheet continues to improve

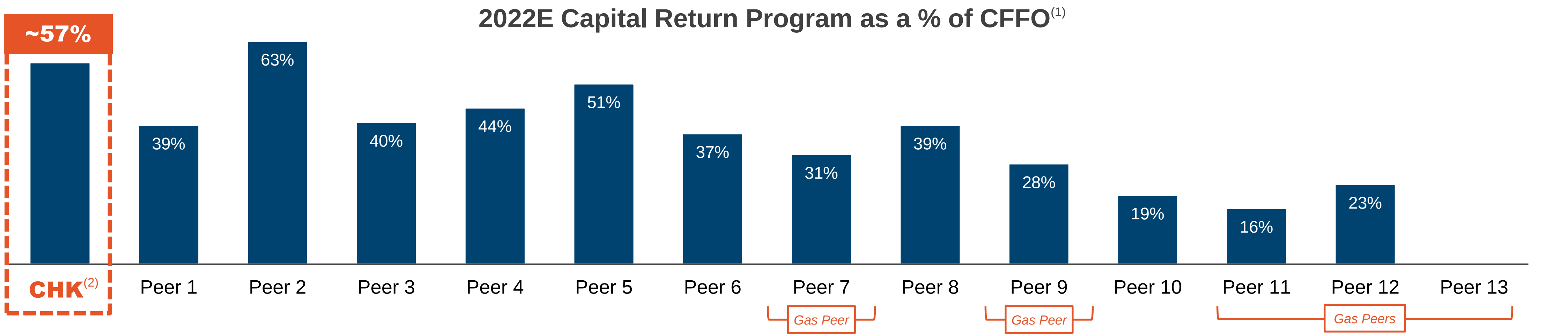
~$700mm of annualized FCF
per $0.50/mcf[1] change



Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix
(1) Assumes 20:1 gas to oil ratio; no change to current development plan; excluding hedges
(2) Stress case includes $4.50 HHUB / $85 WTI in 2022; $3.50 / $75 in 2023 and $3.00 / $65 thereafter
(3) Adjusted strip deck utilizes NYMEX strip pricing as of 6/17/2022 for 2022 ($6.49 HHUB / $102 WTI) and 2023 ($5.49 / $91), then $4.00 / $75 thereafter

Leading Capital Return Program

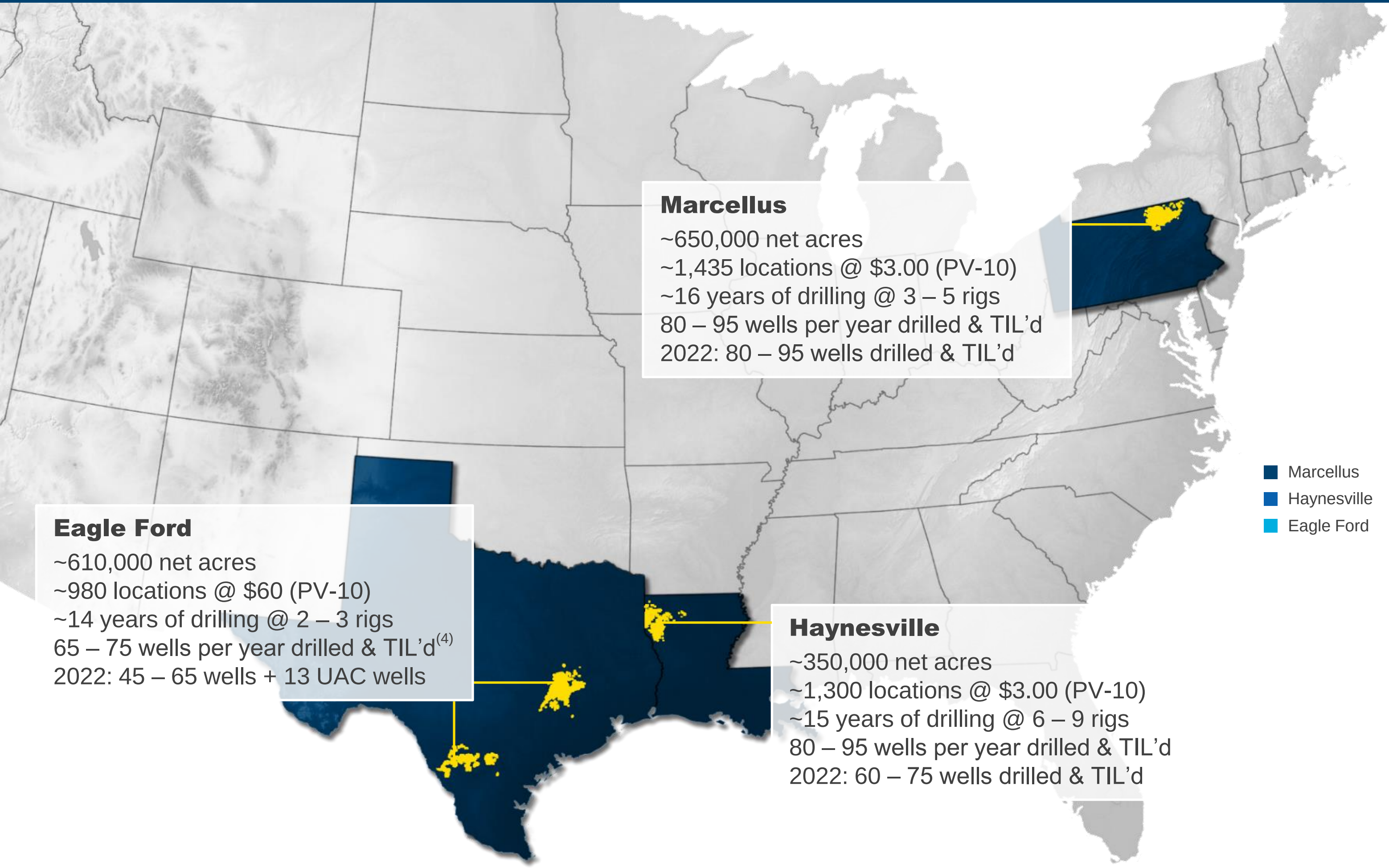




Note: Peers include APA, AR, CNX, CTRA, DVN, EOG, EQT, FANG, MRO, OVV, PXD, RRC, SWN
(1) All 2022 estimates per broker consensus as of 6/17/2022; frameworks per public disclosures
(2) Assumes $1.0B of $2.0B equity repurchase authorization completed by the end of 2022

Refocused and High-Graded Portfolio

5-YEAR PLAN (2022E – 2026E)

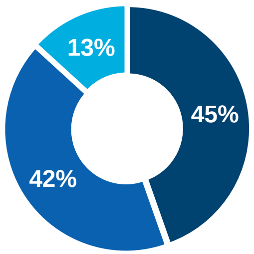


Marcellus
~650,000 net acres
~1,435 locations @ $3.00 (PV-10)
~16 years of drilling @ 3 – 5 rigs
80 – 95 wells per year drilled & TIL'd
2022: 80 – 95 wells drilled & TIL'd

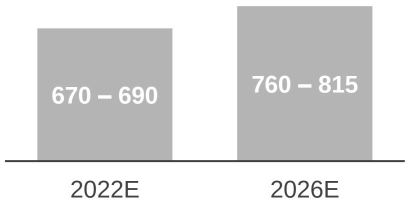
Eagle Ford
~610,000 net acres
~980 locations @ $60 (PV-10)
~14 years of drilling @ 2 – 3 rigs
65 – 75 wells per year drilled & TIL'd[4]
2022: 45 – 65 wells + 13 UAC wells

Haynesville
~350,000 net acres
~1,300 locations @ $3.00 (PV-10)
~15 years of drilling @ 6 – 9 rigs
80 – 95 wells per year drilled & TIL'd
2022: 60 – 75 wells drilled & TIL'd

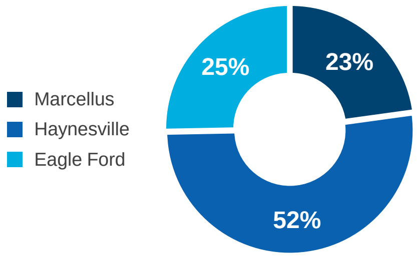
Production[1] by Asset



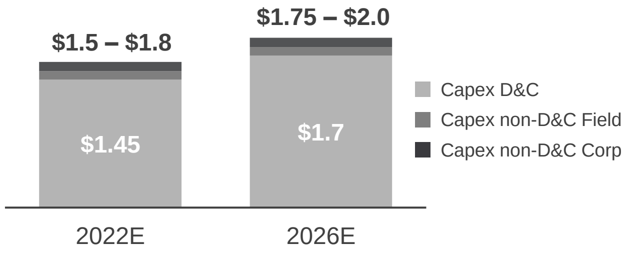
Production[1] (mboe/d)



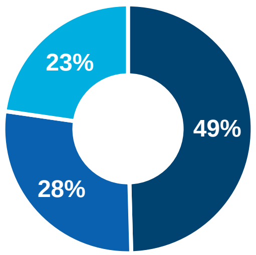
D&C Capital by Asset



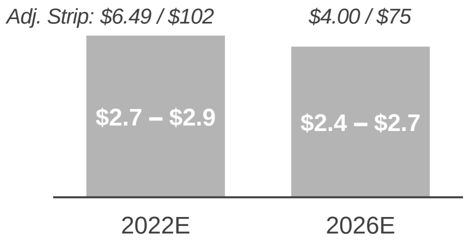
Capital Plan[2] ($B)



Free Cash Flow[3] by Asset

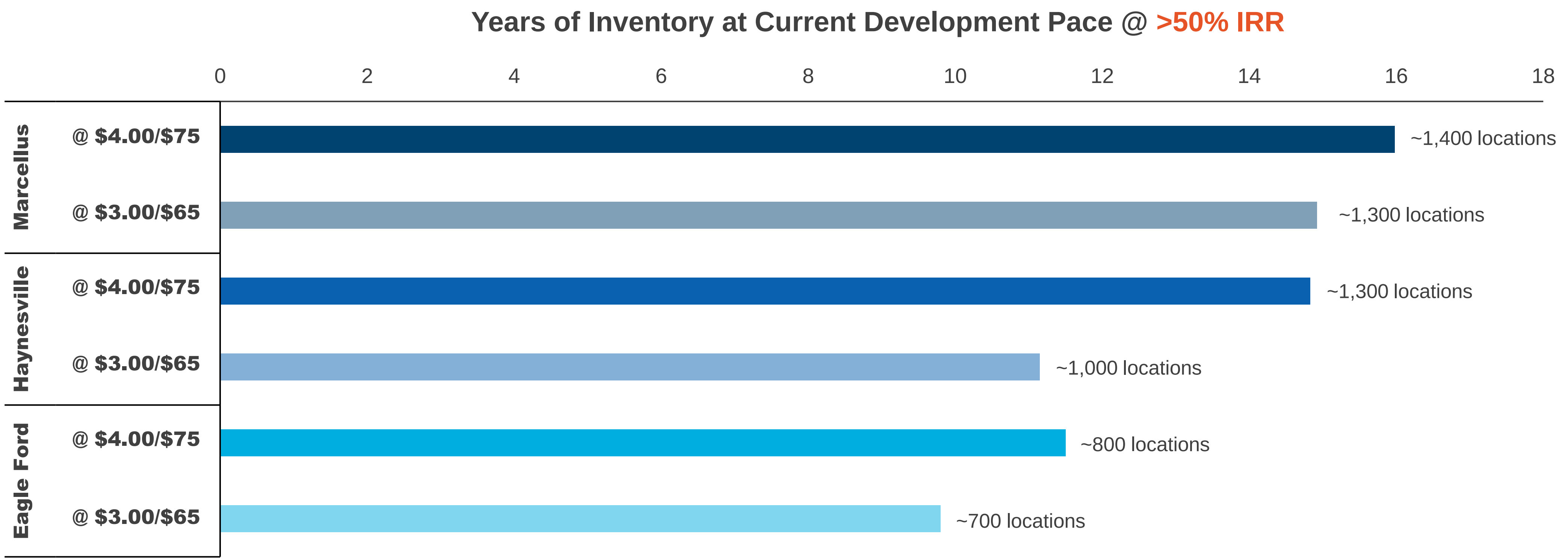


Free Cash Flow[3] ($B)



(1) Assumes 6:1 ratio mcfe/boe
(2) Capex non-D&C Field includes workover, infrastructure and leasehold; Capex non-D&C Corp includes PP&E, G&G and cap G&A and interest
(3) Adjusted strip deck utilizes NYMEX strip pricing as of 6/17/2022 for 2022 ($6.49 HHUB / $102 WTI) and 2023 ($5.49 / $91), then $4.00 / $75 thereafter
(4) No future Austin Chalk development is currently reflected in the plan
Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix; all values assume closing of Chief assets on 3/9/2022 and divestiture of Powder River Basin assets on 3/25/2022

Extensive High-Return Inventory



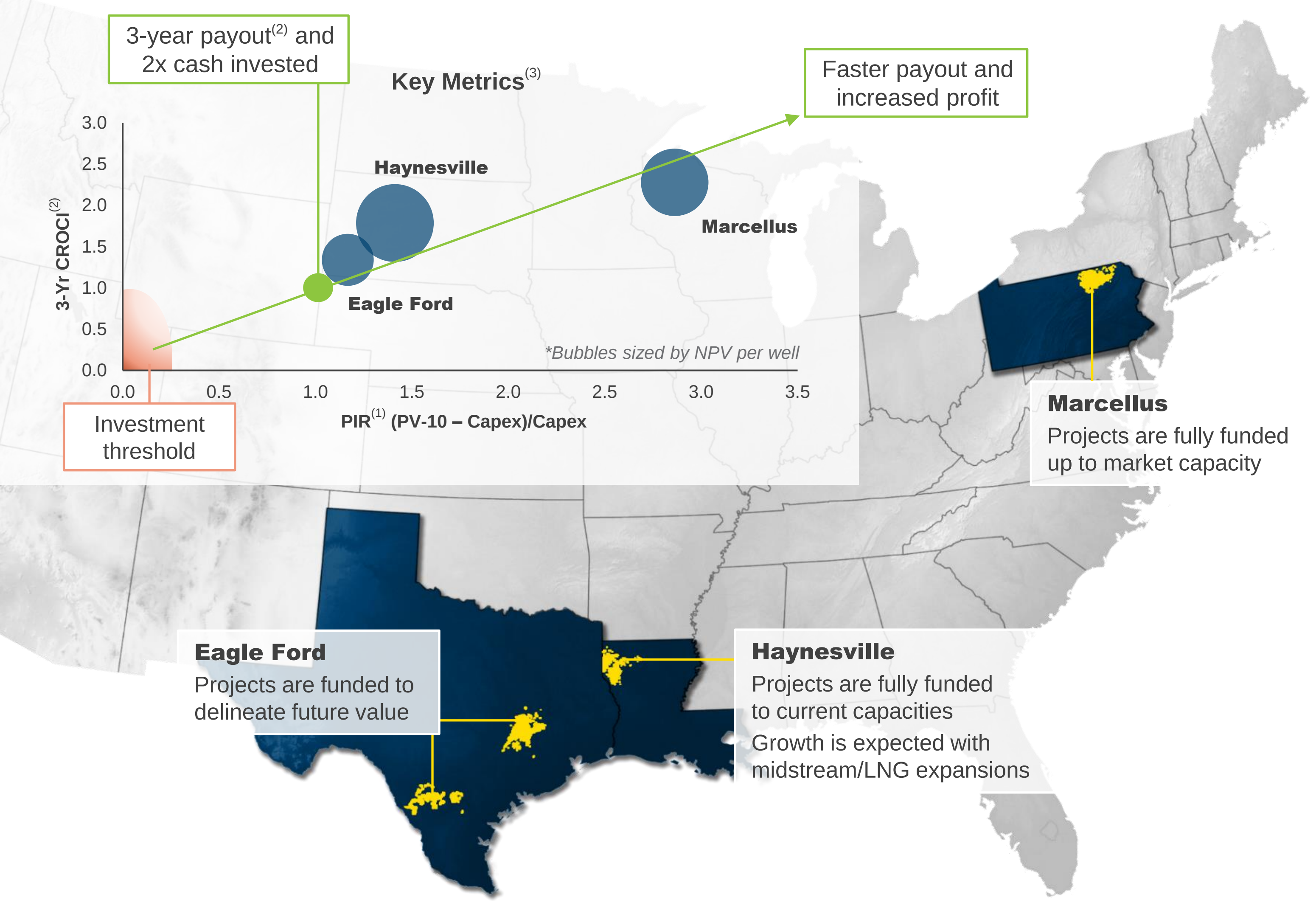
>1,750 locations at $3.00/$65 Pricing

>2,500 locations at $4.00/$75 Pricing

@ **>100% IRR**

(1) Location counts are based on existing acreage as of 1/1/2022 pro forma for Chief, and does not include zones still in early evaluation such as UAC or exploration wells

Return-Focused Capital Allocation Drives Cash Flow



- Low reinvestment ratio through commodity price cycles
- Allocation optimized on investment KPIs: PIR[1], CROCI[2] and NPV
- Maximize current midstream capacity
- ~5% capex allocated to projects focused on expanding resource base
- Annual reallocation of capital, results monitored, and program adjusted real-time with integrated data systems

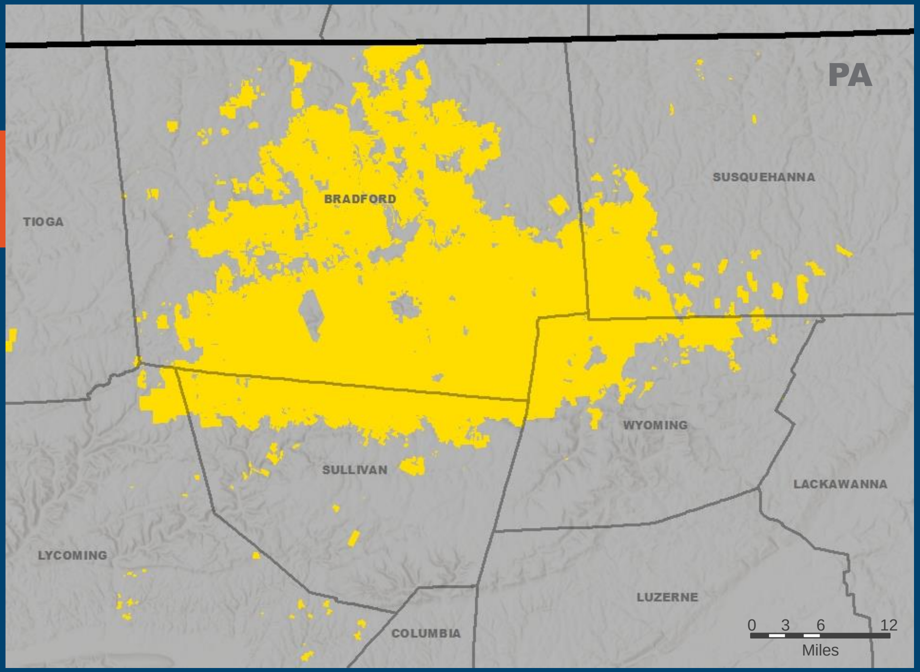
(1) PIR – Profit Investment Ratio – (PV-10 less Capex invested) / Net Capex. Excludes South Texas fixed Minimum Volume Commitment contract
(2) CROCI – Cash Return on Capital Invested – Cash Returned on Capital Invested is the 3-year EBTDA net of allocated G&A and non-D&C capital; Excludes South Texas fixed Minimum Volume Commitment contract
(3) Price deck: $4.00 / $75 WTI flat

Marcellus: Premium Scale, Leading Returns

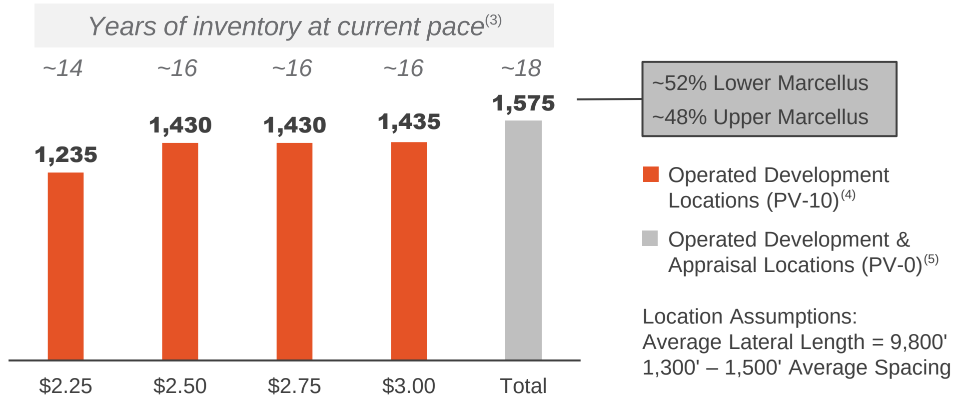
- ~16 years of drilling using 3 – 5 rigs
- 2022E BU EBITDAX[1,2] $3.6B – $3.7B
- Projected to be 100% RSG certified by YE'22
- Delivery of Chief integration and synergies on track
- Basis in 2022 of ~$0.55/mcf is 8% of NYMEX vs. 2020–21 of $0.56/mcf and 19% NYMEX

$7B

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



Gross Inventory by Breakeven



2018 – 2021 Average Capex/12-Month Production
$/mcfe[6]

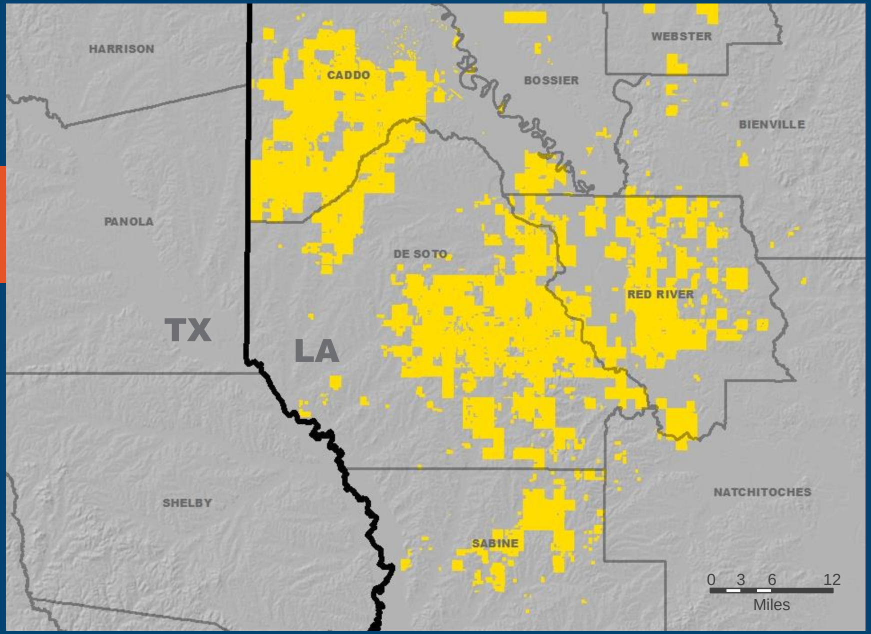
(1) BU level EBITDAX based on adjusted strip deck and excludes hedges and Corporate items
(2) Adjusted strip deck utilizes NYMEX strip pricing as of 6/17/2022 for 2022 ($6.49 HHUB / $102 WTI) and 2023 ($5.49 / $91), then $4.00 / $75 thereafter
(3) Assumes 88 wells per year
(4) 10% IRR at current spacing assumptions, proven development zones
(5) Location counts are based on existing acreage and do not include zones still in early evaluation or exploration wells
(6) Source: Enverus; Peer group includes: AR, CNX, CTRA, EQT, National Fuel, PennEnergy, Repsol, RRC, SWN
Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix

Haynesville: Profitable Growth, Advantaged Markets

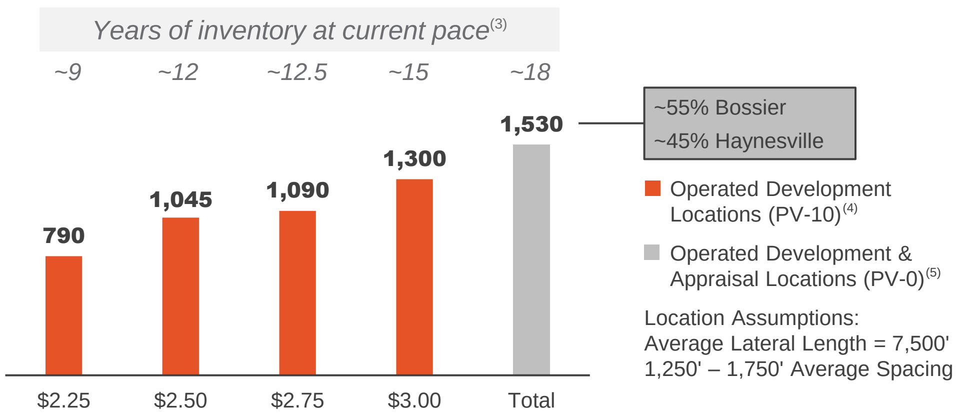
- ~15 years of drilling using 6 – 9 rigs
- 2022E BU EBITDAX[1,2] $2.9B – $3.0B
- First operator to achieve RSG certification basin-wide
- Basis in 2022 of ~$0.60/mcf is 9% of NYMEX vs. 2020–21 of $0.30/mcf and 10% NYMEX
- Vine integration complete, achieved ~$50mm initial annual synergies
- Midstream flexibility with exposure to expanding infrastructure and global gas markets

$4B

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



Gross Inventory by Breakeven



2018 – 2021 Average Capex/12-Month Production
$/mcfe[6]

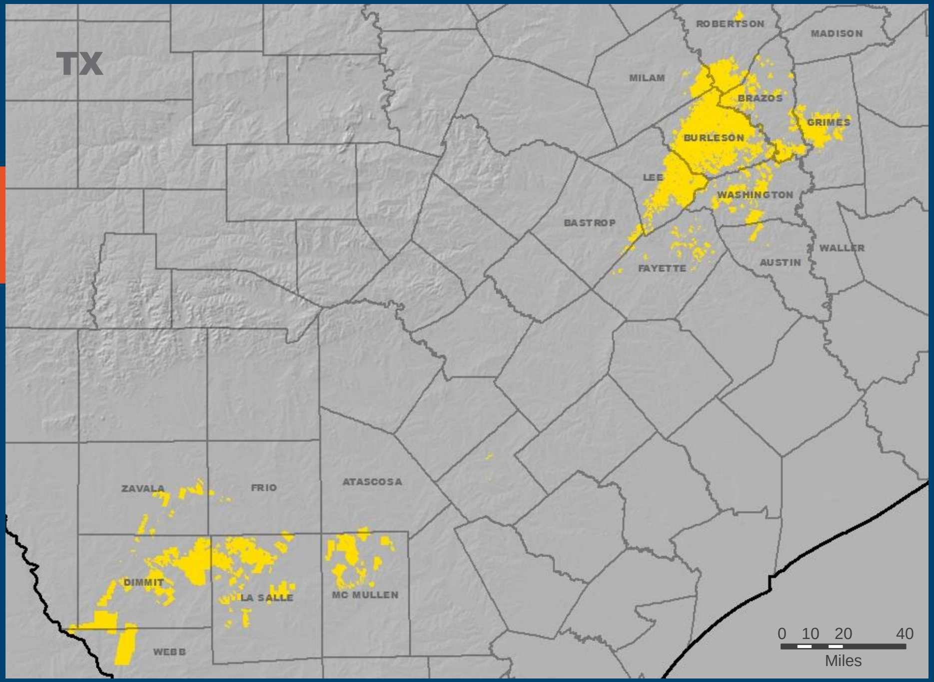
(1) BU level EBITDAX based on adjusted strip deck and excludes hedges and Corporate items
(2) Adjusted strip deck utilizes NYMEX strip pricing as of 6/17/2022 for 2022 ($6.49 HHUB / $102 WTI) and 2023 ($5.49 / $91), then $4.00 / $75 thereafter
(3) Assumes 88 wells per year
(4) 10% IRR at current spacing assumptions, proven development zones
(5) Location counts are based on existing acreage and do not include zones still in early evaluation or exploration wells
(6) Source: Enverus; Peer group includes: Aethon, BP, CRK, XOM, Rockcliff, Sabine, SWN
Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix

Eagle Ford: Superior Margin, Sustainable Free Cash Flow

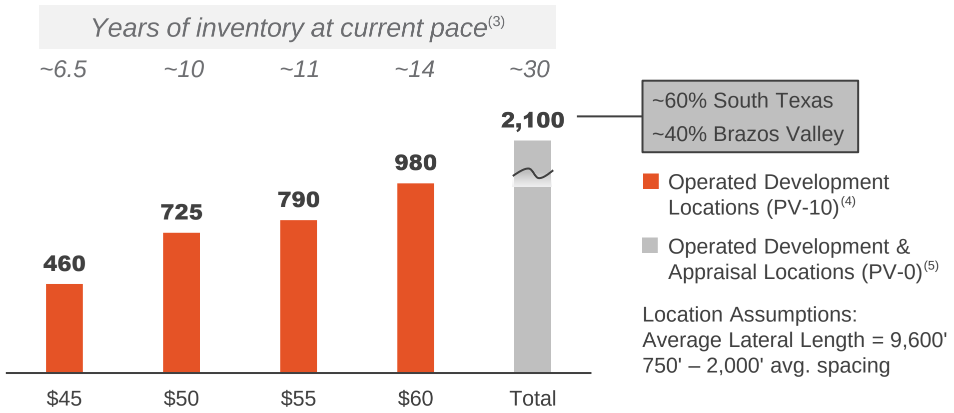
- ~14 years of drilling using 2 – 3 rigs
- 2022E BU EBITDAX[1,2] $1.9B – $2.0B
- Eliminated routine flaring on wells completed 2021+
- Emerging Austin Chalk potential, ~13 wells in 2022 program
- Minimal offtake constraints with access to premium markets
- Gas MVC shortfall projected to decline by 50% YoY

$3B

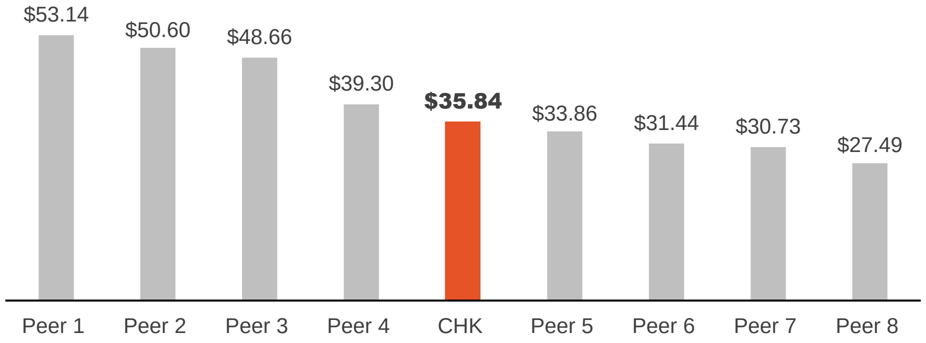
5-year projected FCF[2] *net of allocated hedges, corporate items and taxes*



Gross Inventory by Breakeven



2018 – 2021 Eagle Ford-STX Average Capex/12-Month Production $/boe[6]



(1) BU level EBITDAX based on adjusted strip deck and excludes hedges and Corporate items
(2) Adjusted strip deck utilizes NYMEX strip pricing as of 6/17/2022 for 2022 ($6.49 HHUB / $102 WTI) and 2023 ($5.49 / $91), then $4.00 / $75 thereafter
(3) Assumes 70 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
(6) Source: Enverus; Peer group includes: CPE, DVN, EOG, Mesquite, MGY, MRO, MUR, SM
Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix

Value Creation Through Disciplined Accretive M&A

M&A Non-Negotiables	Vine Acquisition / Chief Acquisition / PRB Divestiture
Don't overpay.	Attractive relative to NAV, recent transactions and public multiples
Protect balance sheet.	Committed to maintaining net debt-to-EBITDAX ratio <1.0x down to $2.50/$50
Accretive to key metrics.	Cash flow/share FCF/share FCF yield
Lowers emissions profile, increases RSG capacity.	100% of Haynesville and Marcellus production RSG certified by YE'22
Better, not just bigger.	Capital efficient assets with deep inventory Estimated annual synergies $100 – $120 million Accelerated returning cash to shareholders by increasing base dividend 45% to $2.00/share

Cohesive culture accelerates integration

Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix

Premier Balance Sheet

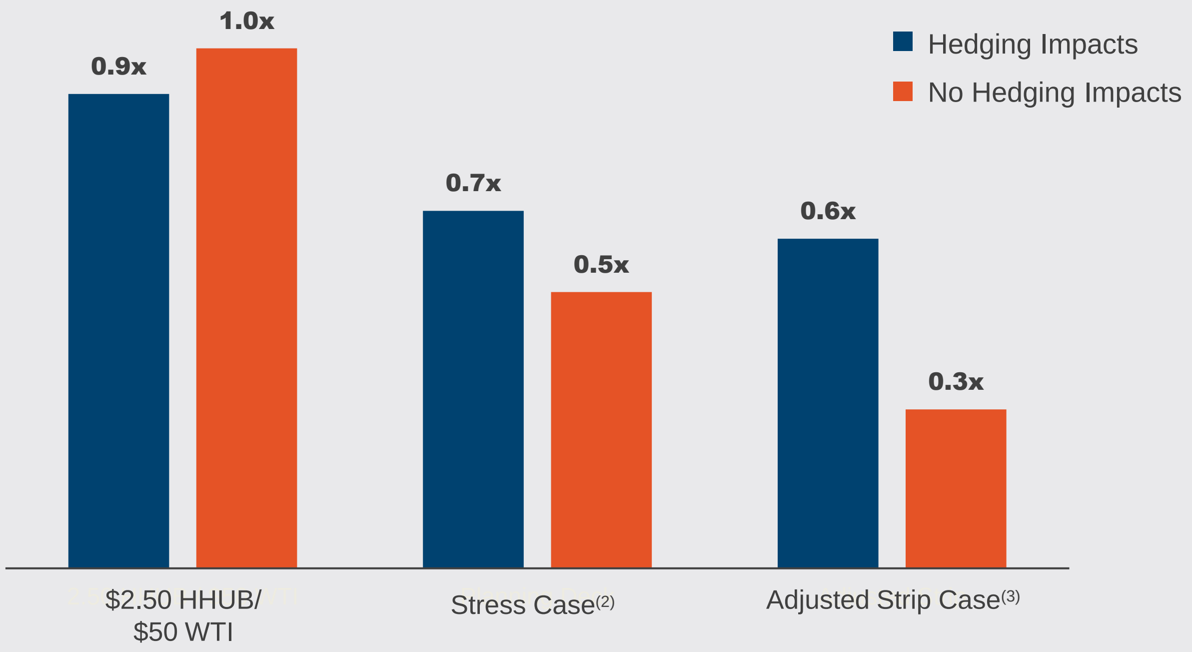
- Committed to maintaining strong balance sheet, net debt-to-EBITDAX of <1.0x
- Investment grade characteristics may facilitate lower cost of capital over time
- Moody's update in May to BB from BB-

Projected YE'22 at 0.5x

maintain <1.0x down to $2.50/$50

2022E Net Debt-to-EBITDAX Resiliency at Various Prices

Normalized[(1)]

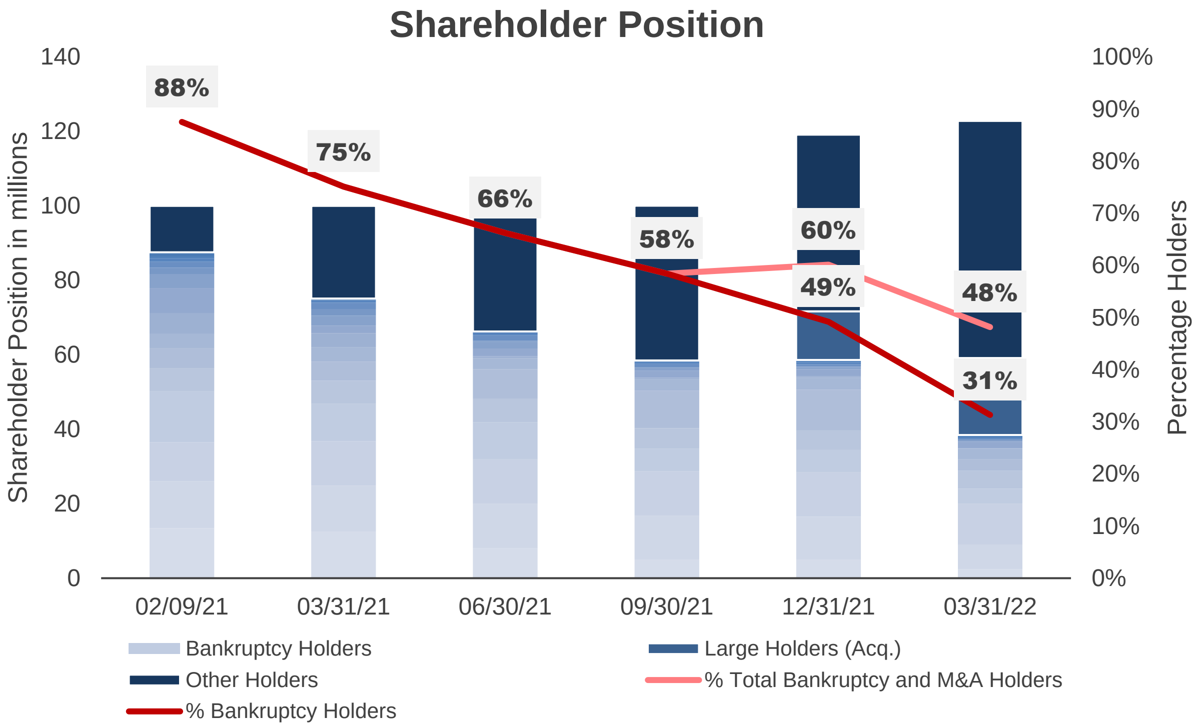


(1) Normalized leverage calculated using 3/31/2022 Net Debt, 2022E production and costs to illustrate EBITDAX at various prices with and without 2022E hedges
(2) Stress case includes $4.50 HHUB / $85 WTI in 2022; $3.50 HHUB / $75 WTI in 2023 and $3.00 HHUB / $65 WTI thereafter
(3) Adjusted strip deck utilizes NYMEX strip pricing as of 6/17/2022 for 2022 ($6.49 HHUB / $102 WTI) and 2023 ($5.49 / $91), then $4.00 / $75 thereafter
Note: Free Cash Flow and EBITDAX are non-GAAP measures which are defined in the appendix

Shareholder Base Transitioning, Buyback Program to Efficiently Accelerate Turnover

- Daily average trading volume has increased by >50% in 2022 vs. 2021
  - May 2022: 2.4mm shares/day
- Bankruptcy holders have declined from 88% to 31% of shares outstanding
  - 62% of creditors have reduced their position by >50%
- Warrants and related short position
  - Warrants transitioned into arbitrage traders
  - Associated short position in CHK also increased

$2B equity repurchase program
authorized by 2023E



First Quarter 2022 Trading	
Total shares traded	111,759,400
Total shares traded by Creditors	15,683,667
Common Stock shorted by Arbs	4,555,012
Percentage traded by Creditors and Arbs	**18%**

Delivering ESG Excellence

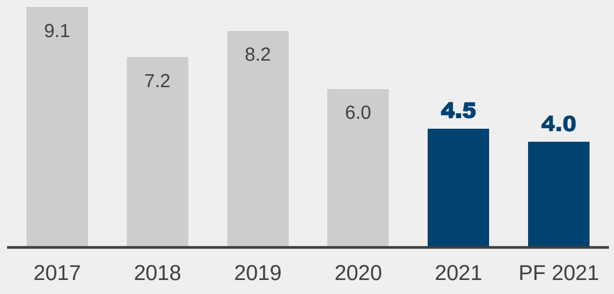
ENVIRONMENTAL

Retrofitting >19,000 pneumatic devices, reducing reported GHG emissions[(1)] by ~40% and methane emissions by ~80% by YE'22

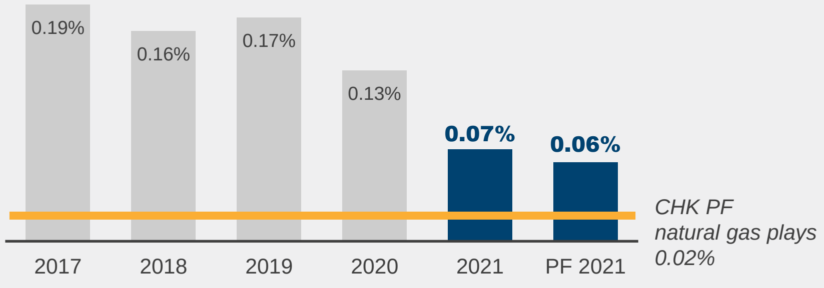
Zero routine flaring on wells completed in 2021 and beyond, enterprise by 2025

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

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 directly tied to company performance, shareholder returns and ESG excellence

(1) As reported under 40 CFR 98 Subpart W

CHK is Poised for Valuation Multiple Re-Rating

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 management incentives

Appendix

2022 ENERGY, POWER & RENEWABLES CONFERENCE

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.

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

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

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

Management's Outlook as of June 22, 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 6/17/2022 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)	**$225 – $275**
Adjusted EBITDAX, based on 6/17/2022 strip prices ($ in millions)(2)	**$4,700 – $4,900**
Total capital expenditures ($ in millions)	$1,500 – $1,800

$ in millions	2022 Projections
Marcellus D&C	$340 – $390
Haynesville D&C	$620 – $670
Eagle Ford D&C	$390 – $440
Powder River D&C	$25
Total D&C	$1,375 – $1,525
Non-D&C Field(3)	$50 – $140
Non-D&C Corp(3)	$75 – $135
Total Capex	$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.

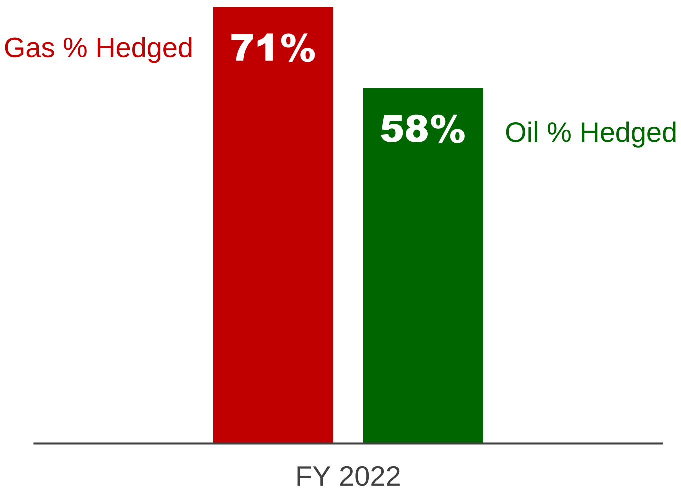
(3) Capex non-D&C Field includes workover, infrastructure and leasehold; Capex non-D&C Corp includes PP&E, G&G and cap G&A and interest.

Hedging Program Reduces Risk, Protects Returns

➤ Since 4/29/2022, CHK has hedged:

- 79 bcf of 2023 gas at $4.34 – $8.49/mcf
- 0.7 mmbbl of 2023 oil at $85.00 – $97.00/bbl

DOWNSIDE PROTECTION LEVELS	RMDR 2022(1)	2023
Gas, $/mcf	$2.90 – $3.40	$3.14 – $4.53
Oil, $/bbl	$44.59	$64.54 – $75.09



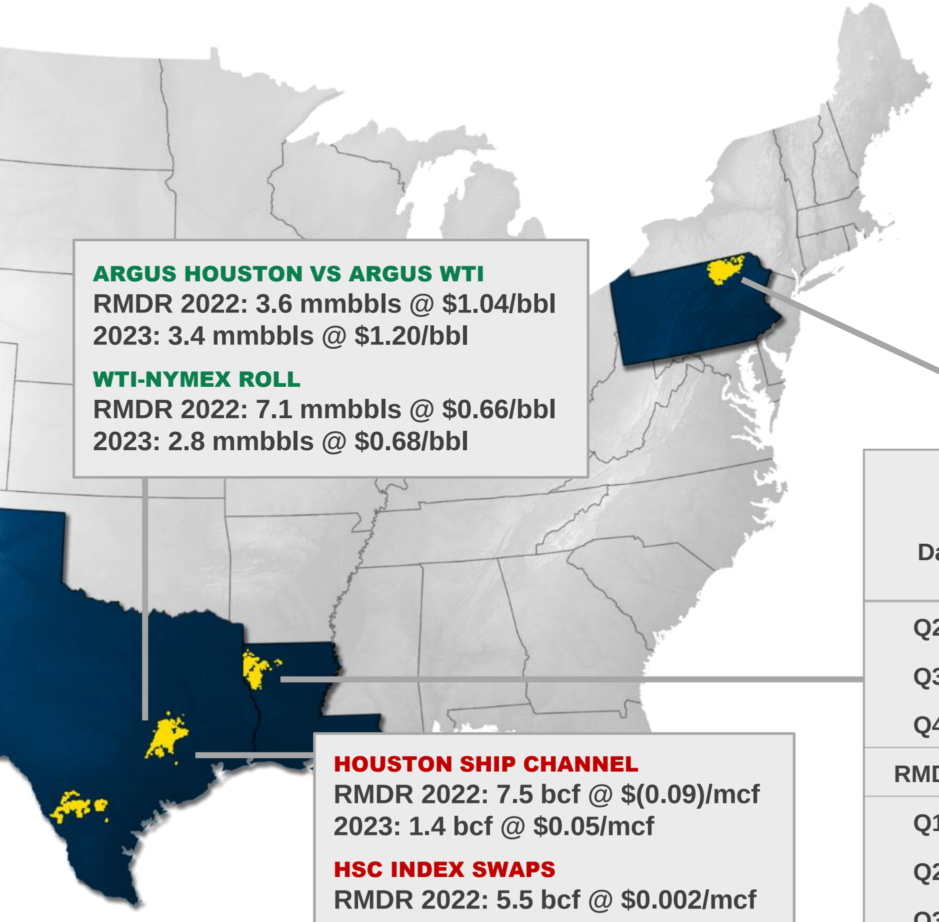
	NATURAL GAS														OIL				
	SWAPS		SWAPTIONS		COLLARS			THREE-WAY COLLARS				CALLS		SWAPS		COLLARS		
Date	Volume *bcf*	Price *$/mcf*	Volume *bcf*	Price *$/mcf*	Volume *bcf*	Bought Put *$/mcf*	Sold Call *$/mcf*	Volume *bcf*	Sold Put *$/mcf*	Bought Put *$/mcf*	Sold Call *$/mcf*	Volume *bcf*	Sold Call *$/mcf*	Volume *mmbbl*	Price *$/bbl*	Volume *mmbbl*	Bought Put *$/bbl*	Sold Call *$/bbl*
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	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 6/17/2022
(1) RMDR 2022 includes 2Q'22 – 4Q'22

Hedged Basis Protection

As of 6/17/2022

- 17% of Marcellus and 42% of Haynesville basis hedged for the remainder of 2022
- Since 4/29/2022, CHK has added basis protection for:
  - 47 bcf of 2Q'22 – 4Q'22 gas at an average differential to NYMEX of $(0.76)
  - 57 bcf of 2023 gas at $(0.61)

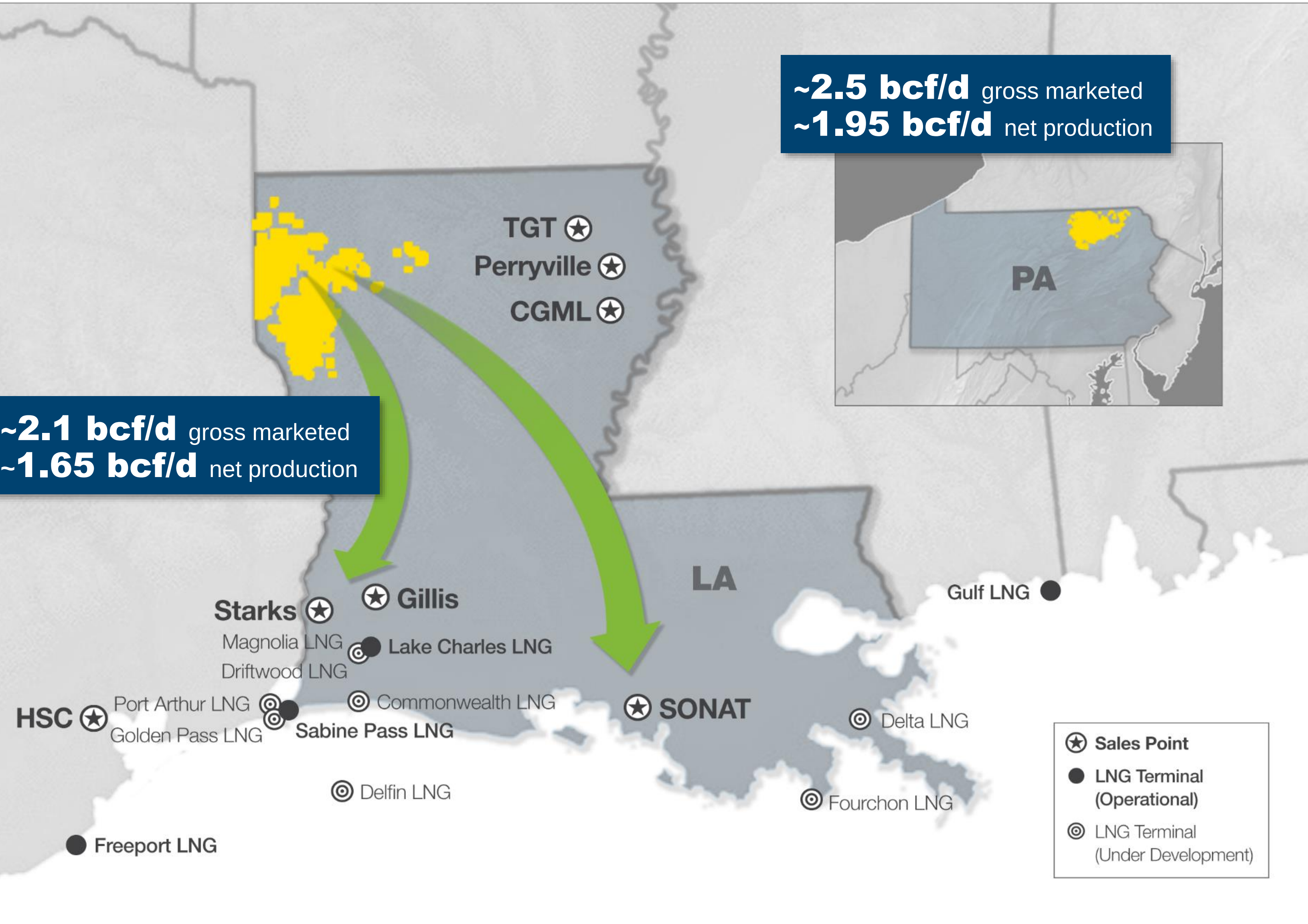


	MARCELLUS						HAYNESVILLE				TRANSPORT SPREAD[(1)]	
	TETCO M3		TGP Z4 300L		LEIDY		CGT MAINLINE		TGT Z1		TETCO M3	
Date	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Price $/mcf
Q2 2022	11.8	(0.80)	4.4	(1.24)	15.6	(1.15)	45.3	(0.37)	15.5	(0.28)	11.3	0.79
Q3 2022	12.0	(0.80)	4.5	(1.24)	26.6	(1.16)	53.1	(0.44)	15.6	(0.28)	11.4	0.79
Q4 2022	8.6	0.68	2.8	(1.08)	10.2	(1.12)	50.7	(0.37)	9.8	(0.23)	9.9	0.77
RMDR '22	**32.4**	**(0.41)**	**11.7**	**(1.20)**	**52.4**	**(1.15)**	**149.1**	**(0.40)**	**41.0**	**(0.26)**	**32.6**	**0.78**
Q1 2023	6.8	1.99	4.2	(1.13)	4.1	(1.07)	32.0	(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)**	**15.1**	**(1.12)**	**106.1**	**(0.28)**	**15.1**	**(0.20)**	**23.4**	**0.76**

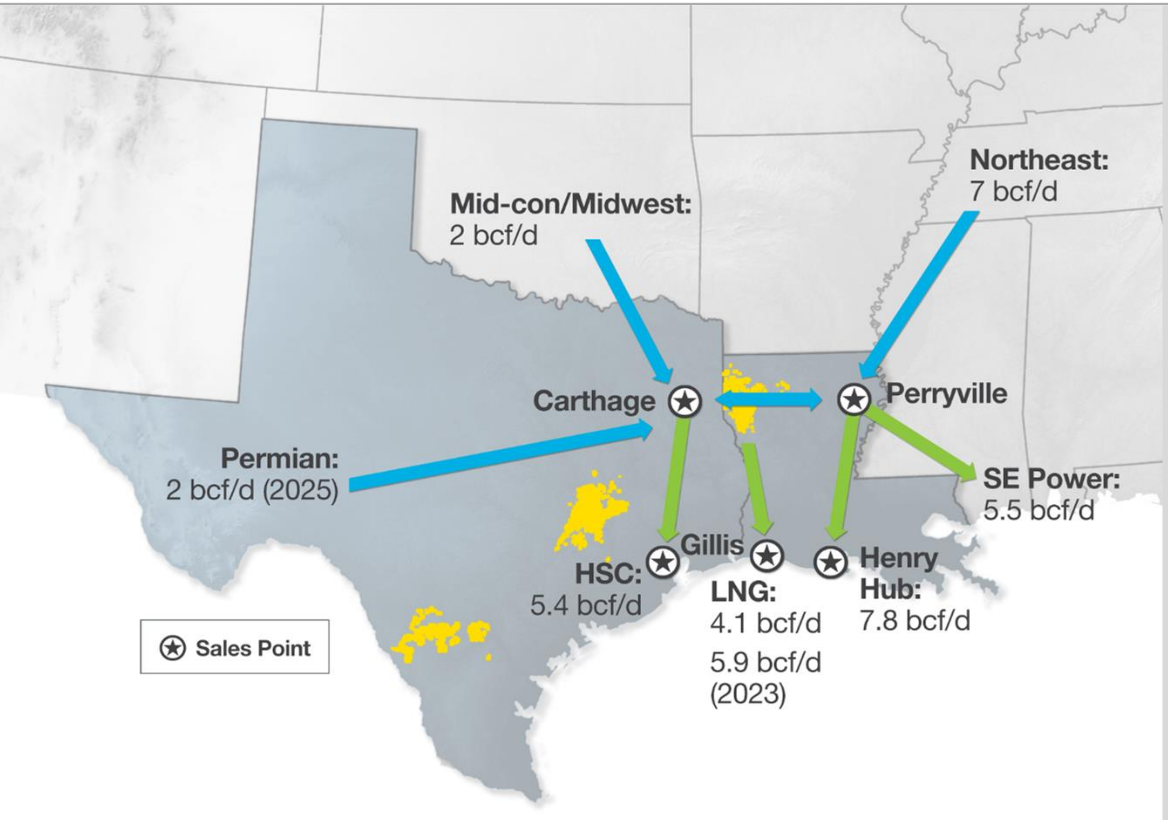
(1) TETCO M3 transport spread vs. TGP Z4 300L

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



Haynesville Supply and Demand

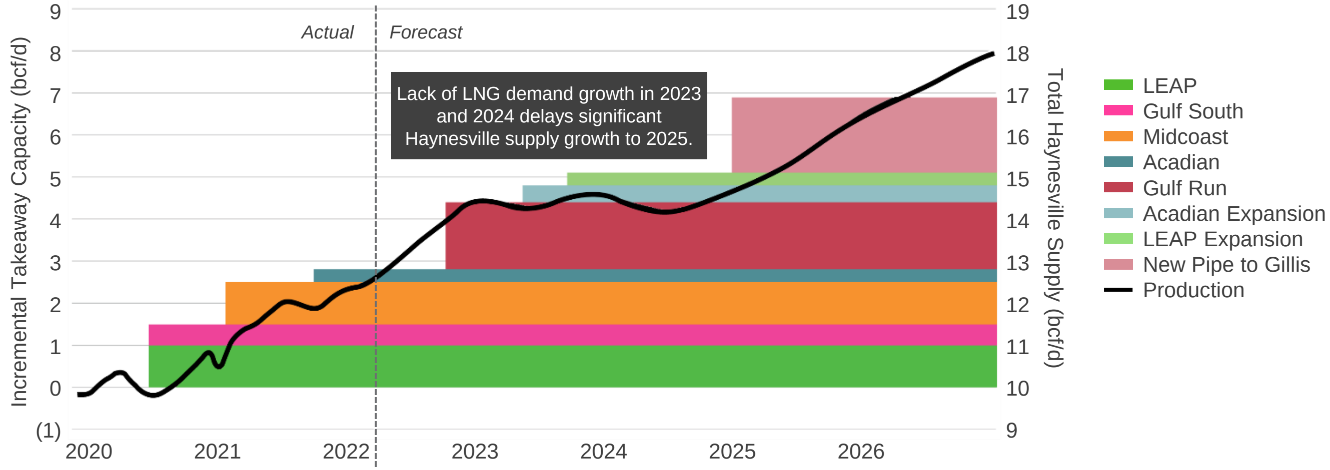


CGML Basis							
2017	2018	2019	2020	2021	2022	2023	2024
($0.12)	($0.15)	($0.21)	($0.21)	($0.35)	($0.49)	($0.31)	($0.27)

	2022	2023	2024	2025
Haynesville	14	15	16	17
Mid-Con/Midwest	2	2	2	2
Permian	0	0	0	2
Northeast	7	7	7	7
Supply	**23**	**24**	**25**	**28**
HSC	5.4	5.4	5.4	5.4
LNG	4.1	5.9	6.7	8.5
HH	7.8	8.3	8.3	8.3
SE Demand	5.5	5.5	5.5	5.5
In Basin	0.9	0.9	0.9	0.9
Demand	**23.7**	**26**	**26.8**	**28.6**

Short-Term Supply Growth and Takeaway

Haynesville Needs Additional Takeaway Projects to Supply Future LNG Demand Growth



Only includes volumes that affect CHK in-basin pricing/takeaway
Sources: WoodMac, Enverus, S&P

Haynesville Gas Sales

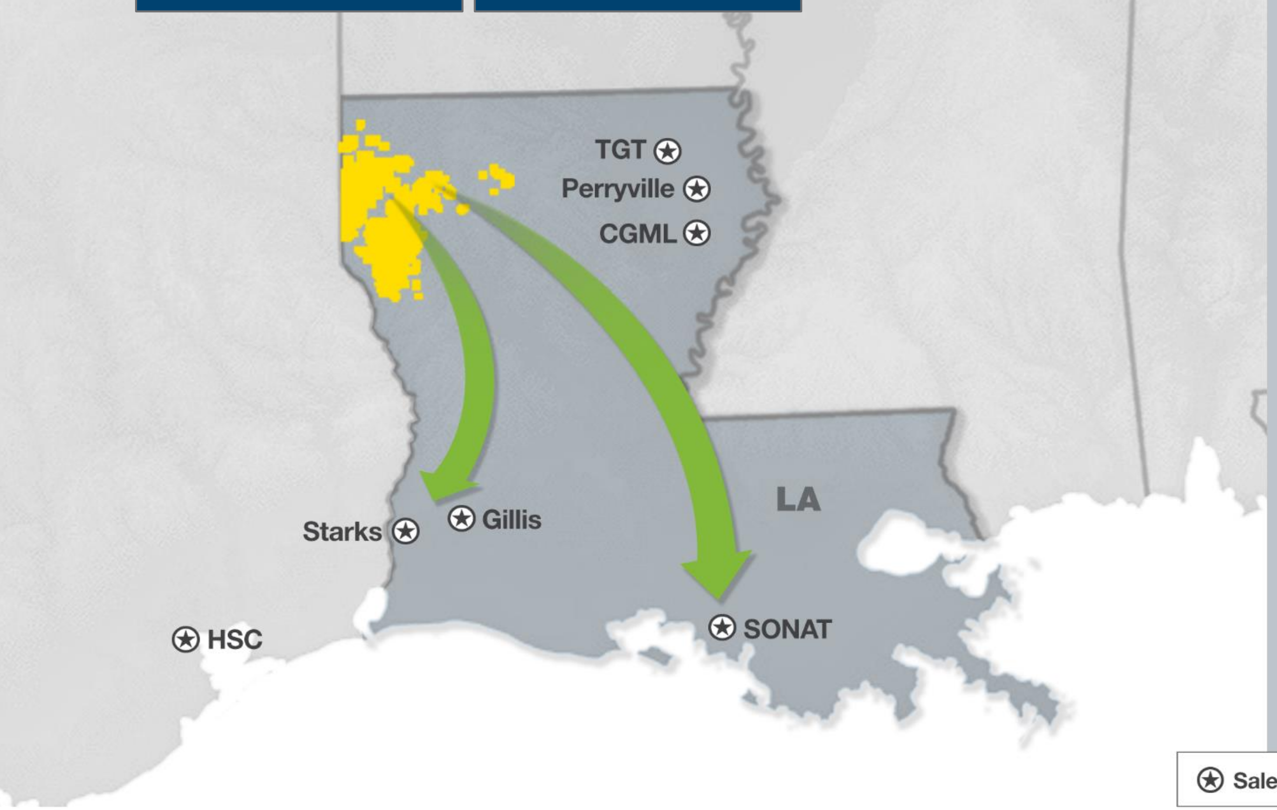
42% of basis hedged for remainder of 2022

HISTORICAL DEDUCT FROM NYMEX ($)[1]	
CGML	($0.28)
TGT	($0.20)
10% of NYMEX	

CURRENT DEDUCT FROM NYMEX ($)[1]	
CGML	($0.42)
TGT	($0.36)
9% of NYMEX	

HAYNESVILLE TOTAL PRODUCTION

CGML: 60%
TGT: 25%
Other Gulf Coast: 15%



Marcellus Gas Sales

17% of basis hedged for remainder of 2022

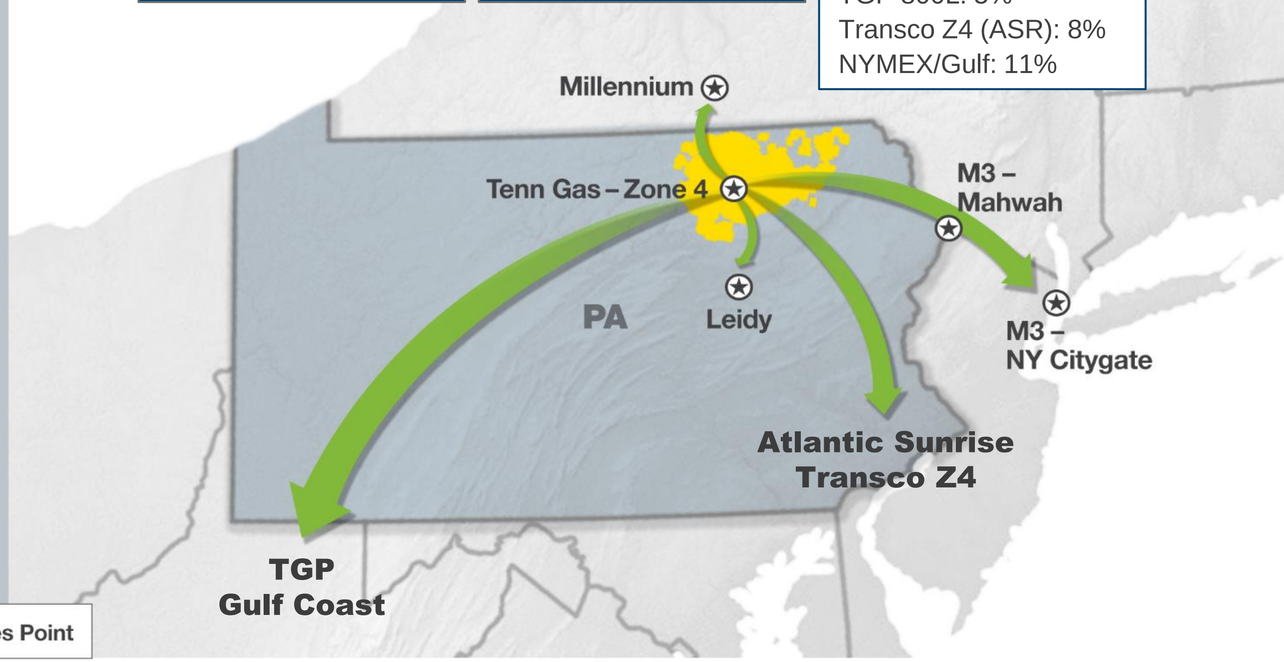
HISTORICAL DEDUCT FROM NYMEX ($)[1]	
TGP 800L	($0.11)
Transco Z4	($0.03)
TETCO M3	($0.30)
TGP Z4	($0.90)
Leidy	($0.83)
Atlantic Sunrise	($0.02)
19% of NYMEX	

CURRENT DEDUCT FROM NYMEX ($)[1]	
TGP 800L	($0.18)
Transco Z4	$0.12
TETCO M3	$0.50
TGP Z4	($1.26)
Leidy	($1.16)
Atlantic Sunrise	$0.12
8% of NYMEX	

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 compared to FY 2022 guided midpoint and strip as of 6/17/2022

5-Year Development Plan Assumptions

	Marcellus		Haynesville		Eagle Ford	
	Lower	Upper	Haynesville	Bossier	South Texas	Brazos Valley
FY'22E Net Prod (bcf/d) / (mboe/d)	1.9 – 2.0		1.6 – 1.7		62 – 68	28 – 32
5-yr Annual PDP Decline	~20%		~30%		~15%	
Production Expense ($/mcf) / ($/boe)	$0.09 – $0.11		$0.25 – $0.35		$4.00 – $5.50	$7.50 – $7.75
Differential to NYMEX ($/mcf) / ($/bbl)	($0.50) – ($0.60)		($0.55) – ($0.65)		$1.25 – $1.50	($0.10) – ($0.30)
GP&T[1] ($/mcf) / ($/boe)	$0.55 – $0.65		$0.45 – $0.55		2022: $14.50 – $15.50 2024+: $10.75 – $11.75	$0.30 – $0.40
FY'22E BU EBITDAX[2] Margin ($/mcf) / ($/boe)	$5.05 – $5.20		$4.90 – $5.00		$48.50 – $50.50	$68.50 – $72.50

	Lower	Upper	Haynesville	Bossier	South Texas	Brazos Valley
Net Acreage	~650,000		~350,000		~220,000	~390,000
Well Spacing (ft)	1,300 – 1,500		1,250 – 1,500		750 – 1,200	1,500 – 2,000
Avg LL of 2022–26 Drilling Program (ft)	9,500 – 10,500		8,500 – 9,500		10,000 – 11,000	10,000 – 11,000
% of 2022–26 BU Activity	~70%	~30%	~70%	~30%	~65%	~35%
Avg WI / NRI	~50% / ~40%		~85% / ~70%		~60% / ~45%	~95% / ~75%
Drilling[3] ($/ft)	$330	$340	$630	$700	$250	$380
Completion[3] ($/ft)	$360	$400	$550	$740	$330	$480
TIL[3] ($/ft)	$80	$80	$90	$110	$90	$140
Total[3] ($/ft)	**$770**	**$820**	**$1,270**	**$1,550**	**$670**	**$1,000**

(1) GP&T includes fixed Minimum Volume Commitment contract
(2) BU level EBITDAX based on adjusted strip deck and excludes hedges and Corporate items
(3) Represents 5-year gross average: 2022 as previously guided, current market conditions for 2023+