Consistent Returns, Sustainable Future

1Q 2021 Earnings
May 12, 2021

CHESAPEAKE ENERGY

Disclaimers

FORWARD-LOOKING STATEMENTS

This document includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. In some cases, forward-looking statements can be identified by the use of forward-looking terms such as “anticipate,” “estimate,” “believe,” “continue,” “could,” “intend,” “may,” “plan,” “potential,” “predict,” “should,” “will,” “expect,” “objective,” “projection,” “forecast,” “goal,” “guidance,” “outlook,” “effort,” “target,” “trajectory” or the negative of these terms or other comparable terms. However, the absence of these words does not mean that the statements are not forward-looking. These forward-looking statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. These forward-looking statements are subject to known and unknown risks, uncertainties and assumptions that may cause actual results, levels of activity, performance or achievements to be materially different from any future results, levels of activity, performance or achievements expressed or implied by such forward-looking statements. Factors that might cause or contribute to a material difference include the risks discussed in our filings with the SEC and the following: our ability to successfully consummate the restructuring of our existing debt, existing equity interests, and certain other obligations, and emerge from the chapter 11 in bankruptcy court; the impact of the COVID-19 pandemic and its 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; the effects of chapter 11 on our business and the interests of various constituents; risks associated with assumption of contracts in chapter 11, our ability to comply with the covenants under our exit facility and the related impact on our ability to continue as a going concern; the volatility of oil, natural gas and natural gas liquids prices, which are affected by general economic and business conditions, as well as increased demand for (and availability of) alternative fuels and electric vehicles; 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 replace reserves and sustain production; drilling and operating risks and resulting liabilities; our ability to generate profits or achieve targeted results in drilling and well operations; 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 finance reserve replacement costs or satisfy our debt obligations; adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims; legislative and regulatory initiatives addressing environmental concerns, including initiatives addressing the impact of global climate change or further regulating hydraulic fracturing, methane emissions, flaring or water disposal; terrorist activities and/or cyber-attacks adversely impacting the our operations; effects of acquisitions and dispositions and our ability to realize related synergies and cost savings; and effects of purchase price adjustments and indemnity obligations. Additional factors that could affect our future results or events are described under the heading “Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2019 (the “2019 10-K”) and our Quarterly Reports on Form 10-Q for the quarters ended March 31, June 30, and September 30, 2020, and in other reports we file with the U.S. Securities and Exchange Commission from time to time. Readers are cautioned not to place undue reliance on forward-looking statements. All forward-looking statements set forth in this document are qualified by these cautionary statements and there can be no assurance that the actual results or developments anticipated by us will be realized or, even if substantially realized, that they will have the expected consequences to, or effects on, us or our business or operations. Forward-looking statements set forth in this document speak only as of the date hereof, and we do not undertake any obligation to update forward-looking statements to reflect subsequent events or circumstances, changes in expectations or the occurrence of unanticipated events, except to the extent required by law.

NON-GAAP FINANCIAL MEASURES

Certain financial information included herein, including Adjusted EBITDA and Adjusted EBITDAX, are not presentations made in accordance with U.S. GAAP, and use of such terms varies from others in the same industry. Non-GAAP financial measures should not be considered as alternatives to net income (loss), total operating expenses or any other performance measures derived in accordance with U.S. GAAP as measures of operating performance or cash flows as measures of liquidity. Non-GAAP financial measures have important limitations as analytical tools, and you should not consider them in isolation or as substitutes for results as reported under U.S. GAAP. See the Appendix to this presentation for a reconciliation of certain non-GAAP financial measures to the most directly comparable financial measures calculated in accordance with U.S. GAAP.

NATURAL GAS, OIL & NATURAL GAS LIQUIDS RESERVES

The Company’s proved reserves and adjusted proved reserves are those quantities of natural gas, oil, and natural gas liquids, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

The Company’s estimate of its total proved reserves is based on reports prepared by LaRoche Petroleum Consultants, Ltd., independent petroleum engineers, and internal estimates. Factors affecting ultimate recovery include the scope of the Company’s ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, actual drilling results, including geological and mechanical factors affecting recovery rates, and other factors. Estimates may change significantly as development of the Company’s natural gas, oil and natural gas liquids assets provide additional data. The Company’s production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

Chesapeake Today: A Fundamentally Different Company

Strong balance sheet with low leverage

Built to generate sustainable free cash flow

Disciplined capital reinvestment strategy

World-class natural gas assets, with oil optionality and scale to win

Committed to ESG and safety excellence

Chesapeake Value Drivers

Maintain balance sheet strength

Targeting **<1x** long-term leverage[(1)]

Returning cash to shareholders

Launched initial base dividend of $1.375/share/year

~$3B of **FCF**

projected over next five years[(2)]

Disciplined capital reinvestment rate targeting

60 – 70%

to yield positive FCF and 400+ mboe/d on $700mm – $750mm of annual capex

Achieve **net-zero** direct GHG emissions by 2035

Eliminate routine flaring on all new wells completed from 2021 forward, and enterprise-wide by 2025

Reduce methane intensity[(3)] to 0.09% and GHG intensity[(4)] to 5.5 by 2025

(1) Defined as net debt / adjusted EBITDAX. Net debt (non-GAAP) = Total debt (GAAP) – Premiums and issuance costs on debt – Cash and cash equivalents. Adjusted EBITDAX is a non-GAAP financial measure and is defined as earnings before interest, taxes, depreciation and amortization and exploration expenses. See the appendix for a reconciliation of net cash from operating activities to EBITDAX. (2) Free cash flow (non-GAAP) = Net cash provided by (used in) operating activities (GAAP) + Cash paid for reorganization items, net – Capital expenditures. Estimated based on 4/30/2021 strip pricing from 2021 to 2025. (3) Defined as volume methane emissions / volume gross gas produced. (4) Defined as tCO_2e/gross mboe produced.

Starting Strong: 1Q Highlights

Adjusted EBITDAX

$510mm

Strong projected FCF and cash return on capital invested for 2021 and 2022

Balance Sheet Cash

$340mm

~$500mm as of April 30, 2021

Free Cash Flow[(2)]

$329mm

Current net debt[(1)] to 2021E adjusted EBITDAX

0.6x

Launched dividend of

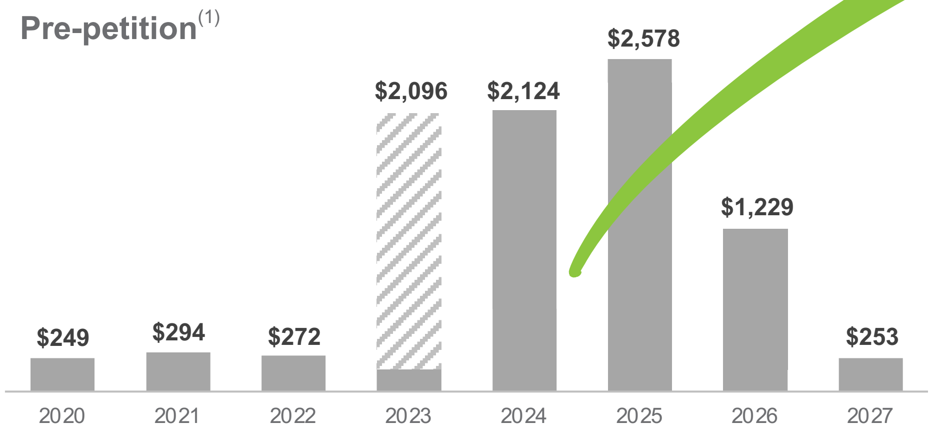
$1.375/share/year

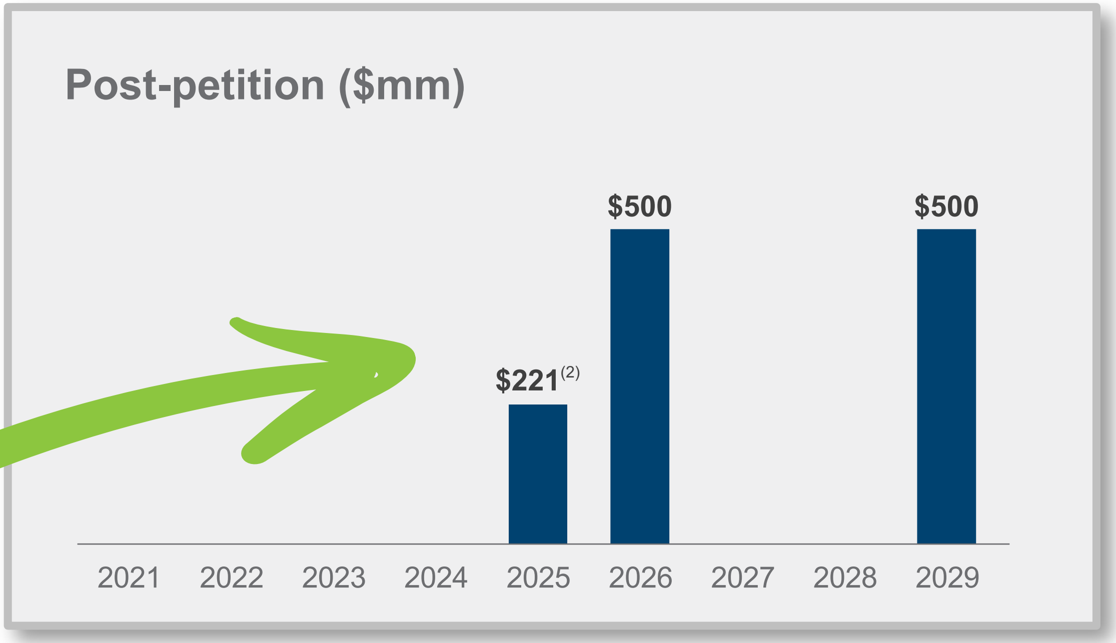
~3.0% annual yield (beginning 2Q'21)

(1) Net debt (non-GAAP) = Total debt (GAAP) – Premiums and issuance costs on debt – Cash and cash equivalents.
(2) Free Cash Flow (non-GAAP) = Net cash provided by (used in) operating activities (GAAP) + Cash paid for reorganization items, net – Capital expenditures.

Restored Balance Sheet

- Significant liquidity
  - $2.5B borrowing base at exit
  - $1.7B available today
- Expected substantial FCF targeted to maintain an undrawn revolver through year-end 2021
- Cash flow projections substantially de-risked through robust hedging program



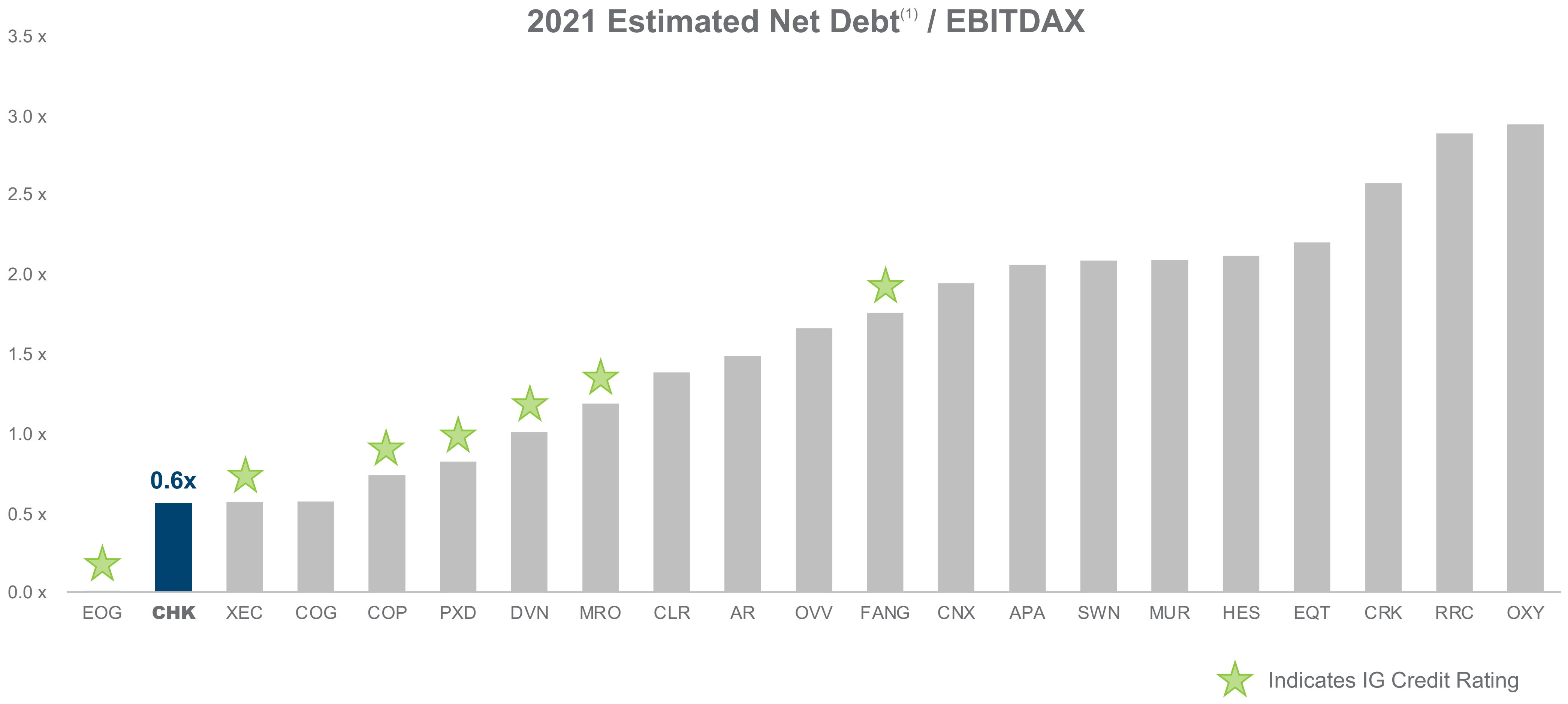


- Total net debt[3] of $881mm as of March 31, 2021

$340mm
cash on hand

(1) As of 6/28/2020. (2) Represents $221mm of CA-CIB and Natixis Tranche B. (3) Net debt (non-GAAP) = Total debt (GAAP) – Premiums and issuance costs on debt – Cash and cash equivalents.

Balance Sheet Improved vs. IG Peers



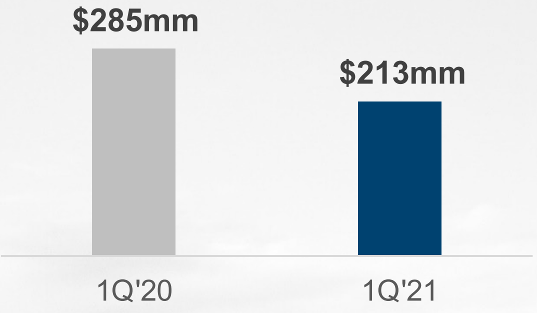
Source: Sell-side analysts' models from Bloomberg as of 5/5/2021. Note: CHK data based on NYMEX strip prices as of 4/30/2021.
(1) CHK calculated as net debt at 3/31/2021 over midpoint of 2021 adjusted EBITDAX guidance as of 5/11/2021. Net debt (non-GAAP) = Total debt (GAAP) – Premiums and issuance costs on debt – Cash and cash equivalents.

Fundamentally Resetting Our Cost Structure

1Q'20 vs. 1Q'21

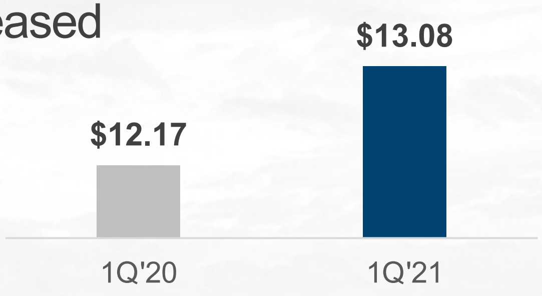
G&A decreased
45%

GP&T decreased
25%



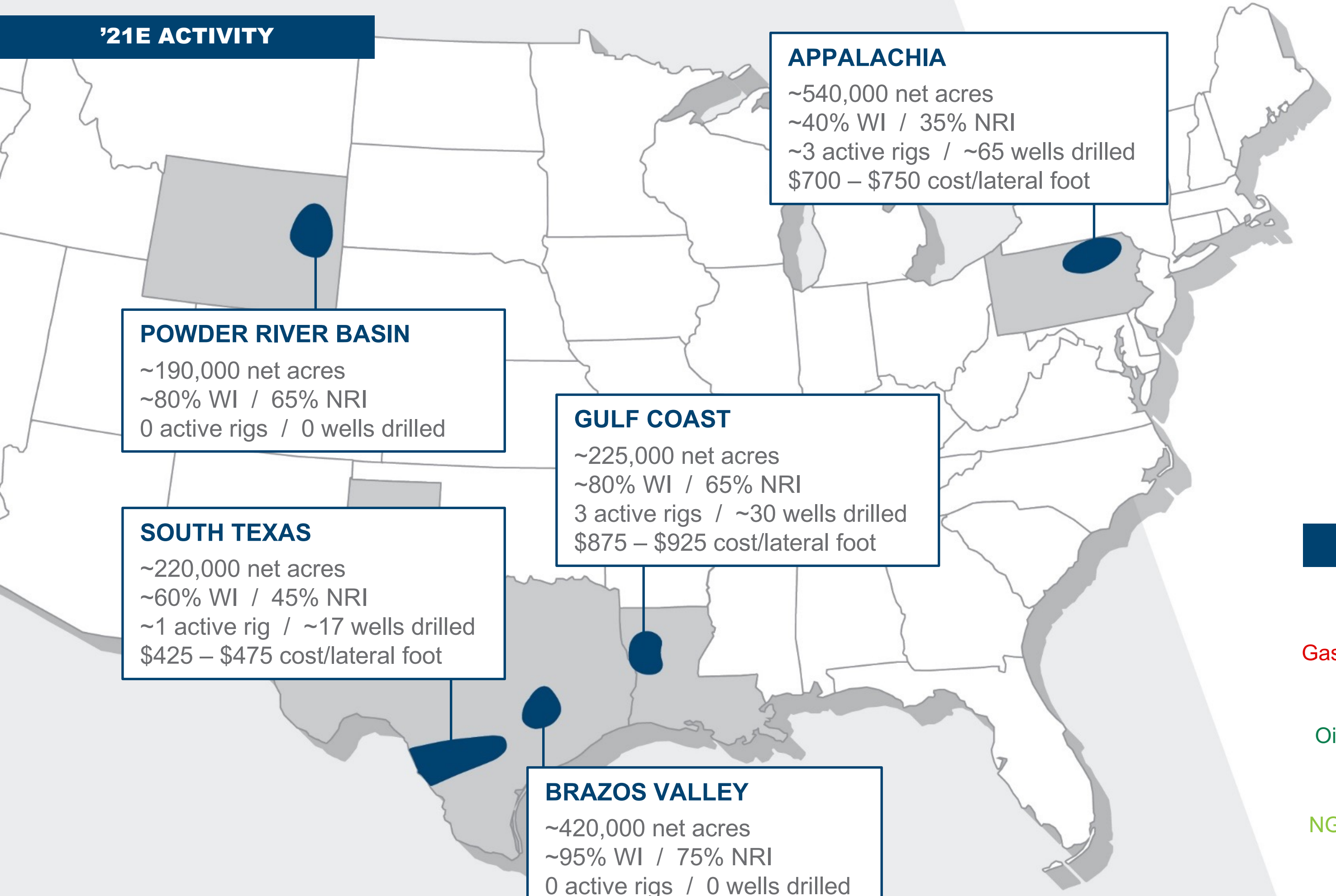
LOE decreased
41%

Adjusted EBITDAX/boe produced increased
7%



Deep Portfolio: Diversified Positions Across Multiple Basins

'21E ACTIVITY



APPALACHIA
~540,000 net acres
~40% WI / 35% NRI
~3 active rigs / ~65 wells drilled
$700 – $750 cost/lateral foot

POWDER RIVER BASIN
~190,000 net acres
~80% WI / 65% NRI
0 active rigs / 0 wells drilled

GULF COAST
~225,000 net acres
~80% WI / 65% NRI
3 active rigs / ~30 wells drilled
$875 – $925 cost/lateral foot

SOUTH TEXAS
~220,000 net acres
~60% WI / 45% NRI
~1 active rig / ~17 wells drilled
$425 – $475 cost/lateral foot

BRAZOS VALLEY
~420,000 net acres
~95% WI / 75% NRI
0 active rigs / 0 wells drilled

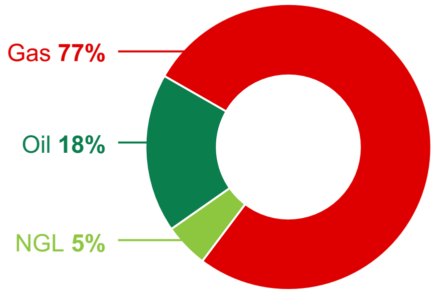
1Q'21 PRODUCTION

~436 mboe/d

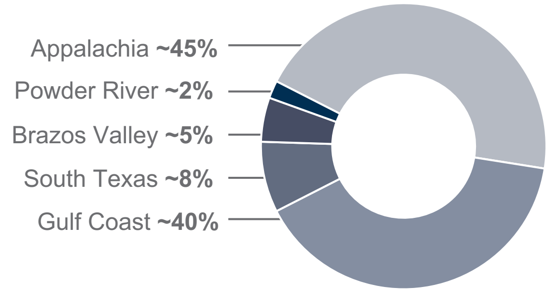
Appalachia: 1,261 mmcf/d	Brazos Valley: 41 mboe/d
Gulf Coast: 532 mmcf/d	Powder River: 23 mboe/d
South Texas: 73 mboe/d	

Projected 2021 Capex
$670mm – $740mm

1Q'21 PRODUCTION MIX



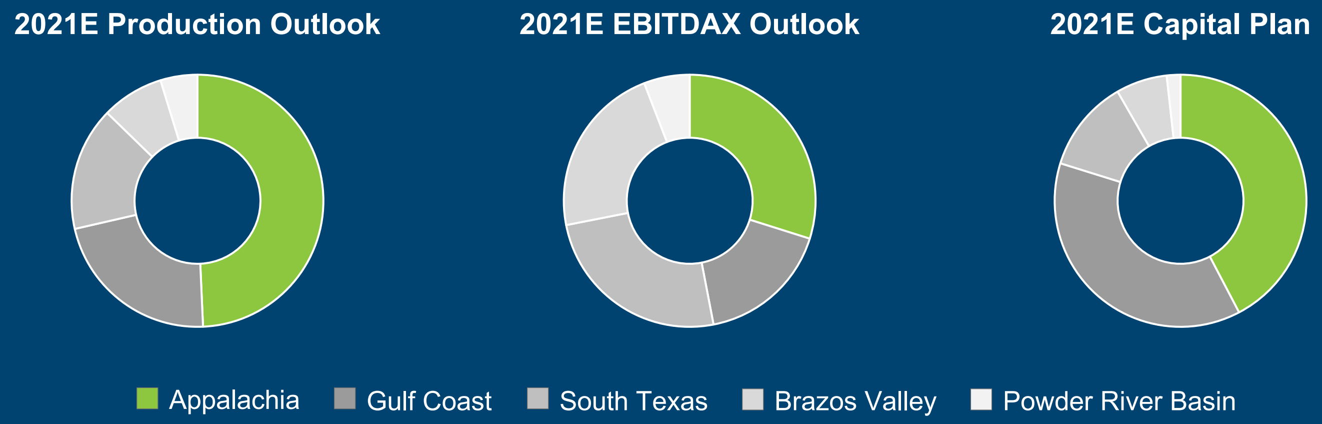
'21E ASSET DEVELOPMENT DETAIL

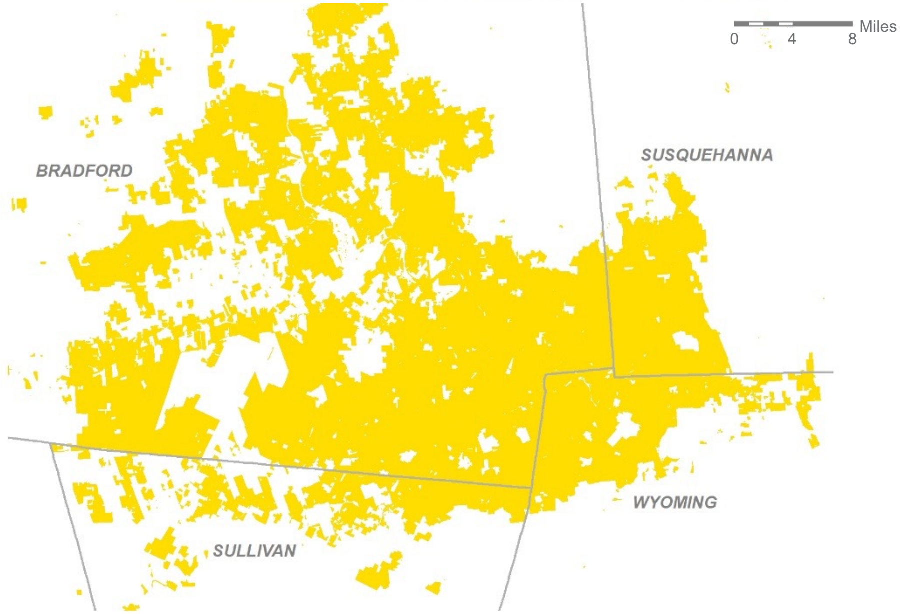


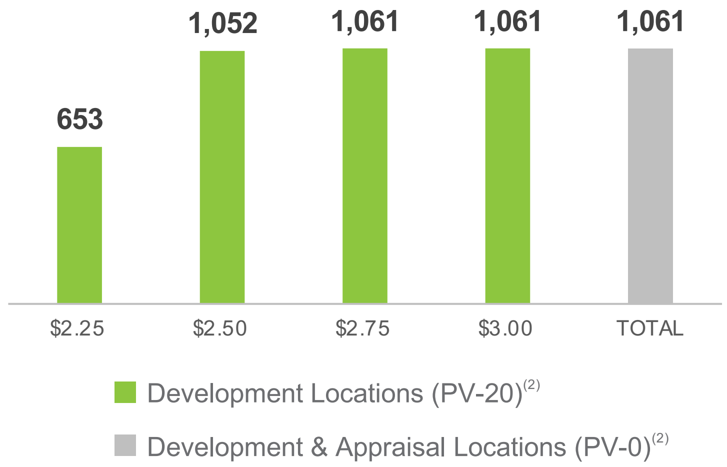
Note: Net acres and projected WI and NRI estimates as of 12/31/2020.

Appalachia: Overview

Acres	PDP Well Count	PDP Decline	1Q'21 Activity
~540,000 ~40% WI, 35% NRI	Op: 963 Non-Op: 292	2020 TILs: 53% Field: 23% (5-yr avg)	Wells drilled: 16 Wells TIL'd: 18

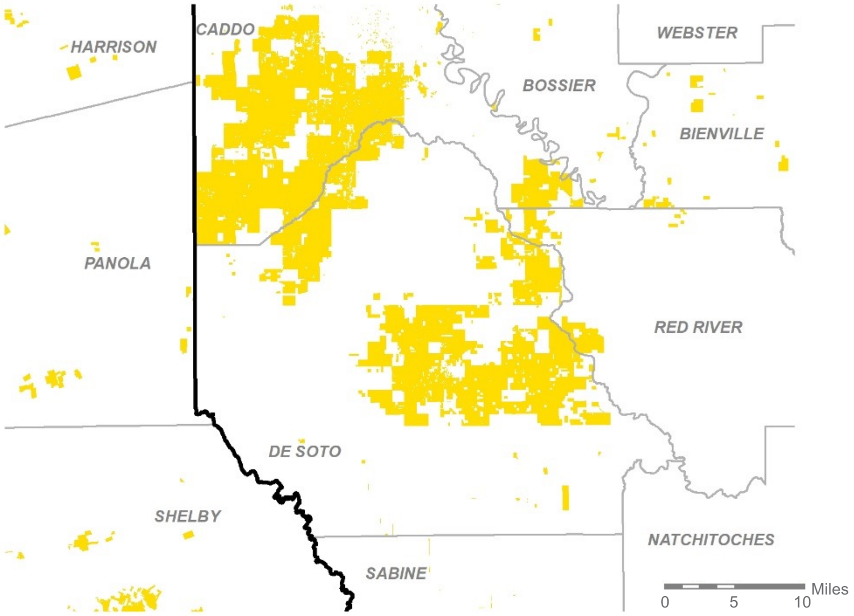






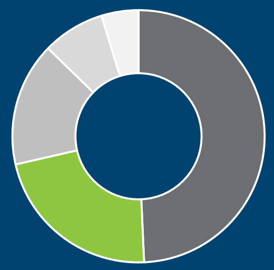
(1) 20% ROR at current spacing assumption, proven development zones.
(2) Location counts do not include exploration wells or zones still in early evaluation.

Gulf Coast: Overview

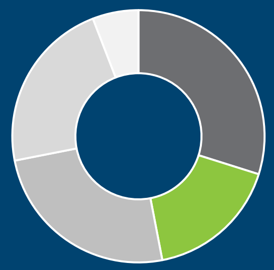


Acres	PDP Well Count	PDP Decline	1Q’21 Activity
~225,000 ~80% WI, 65% NRI	Op: 568 Non-Op: 145	2020 TILs: 62% Field: 22% (5-yr avg)	Wells drilled: 5 Wells TIL’d: 3

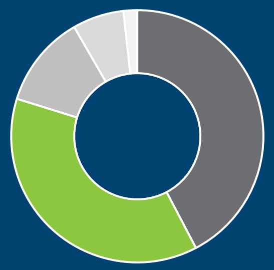
2021E Production Outlook



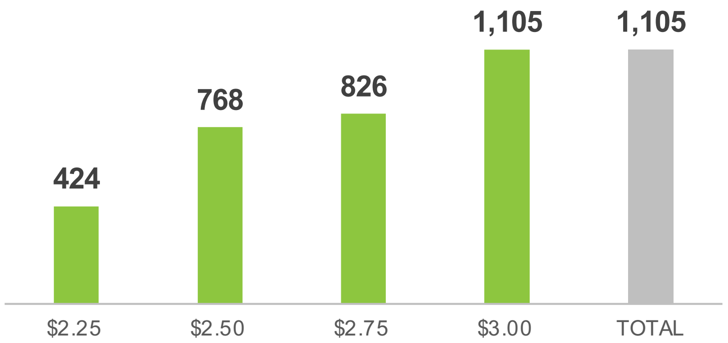
2021E EBITDAX Outlook



2021E Capital Plan



Appalachia Gulf Coast South Texas Brazos Valley Powder River Basin



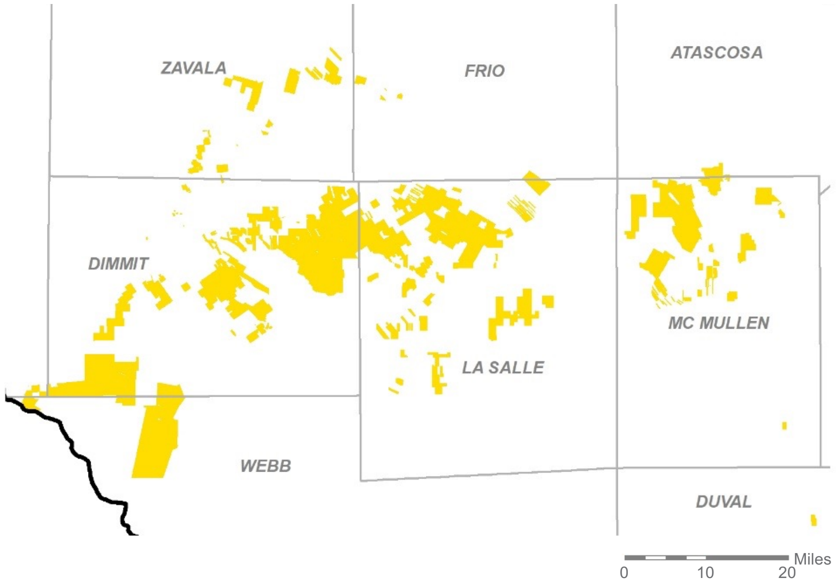
Development Locations (PV-20)[(1)]

Development & Appraisal Locations (PV-0)[(2)]

(1) 20% ROR at current spacing assumption, proven development zones.
(2) Location counts do not include exploration wells or zones still in early evaluation.

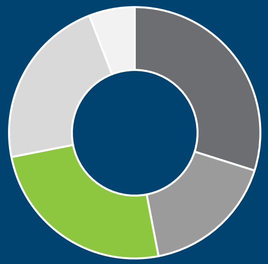
South Texas: Overview

Acres	PDP Well Count	PDP Decline	1Q'21 Activity
~220,000	Op: 2,043	2020 TILs: 59%	Wells drilled: 0
~60% WI, 45% NRI	Non-Op: 119	Field: 16% (5-yr avg)	Wells TIL'd: 3

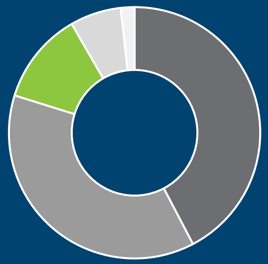


2021E Production Outlook

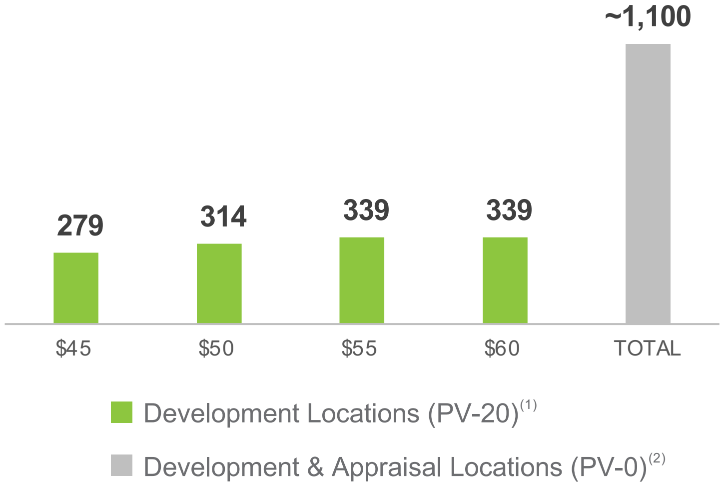
2021E EBITDAX Outlook



2021E Capital Plan



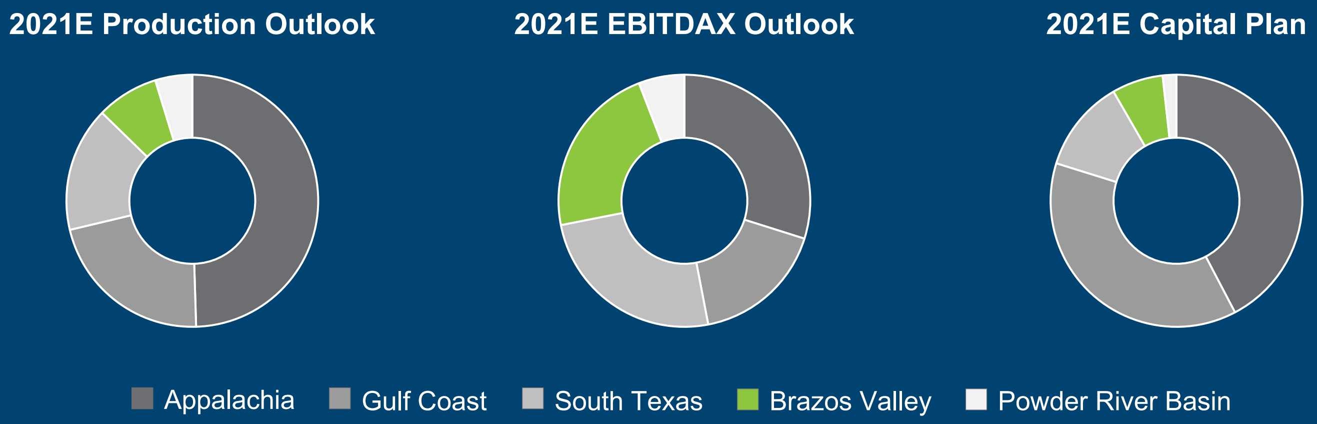
Appalachia | Gulf Coast | South Texas | Brazos Valley | Powder River Basin

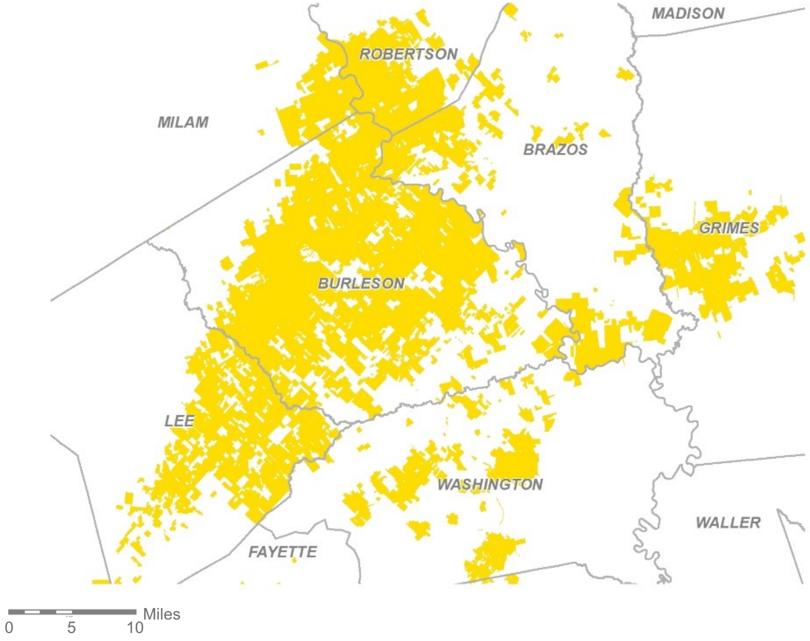


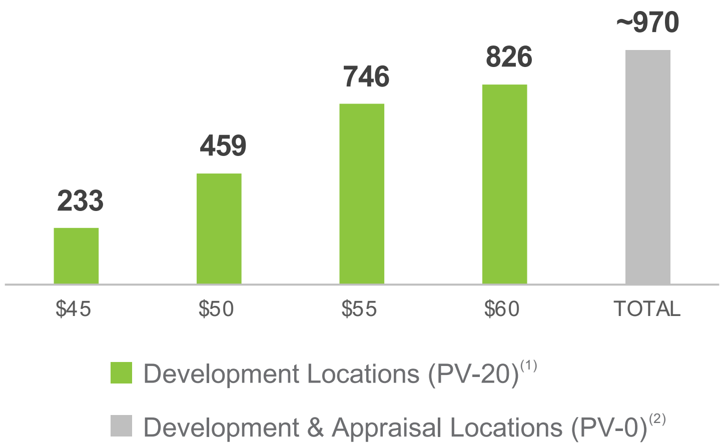
(1) 20% ROR at current spacing assumption, proven development zones; Gas price held constant at $2.50 for location counts.
(2) Location counts do not include exploration wells or zones still in early evaluation.

Brazos Valley: Overview

Acres	PDP Well Count	PDP Decline	1Q'21 Activity
~420,000	Op: 826	2020 TILs: 62%	Wells drilled: 0
~95% WI, 75% NRI	Non-Op: 190	Field: 19% (5-yr avg)	Wells TIL'd: 6







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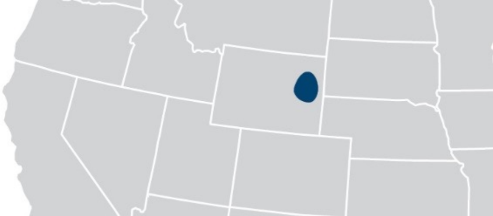
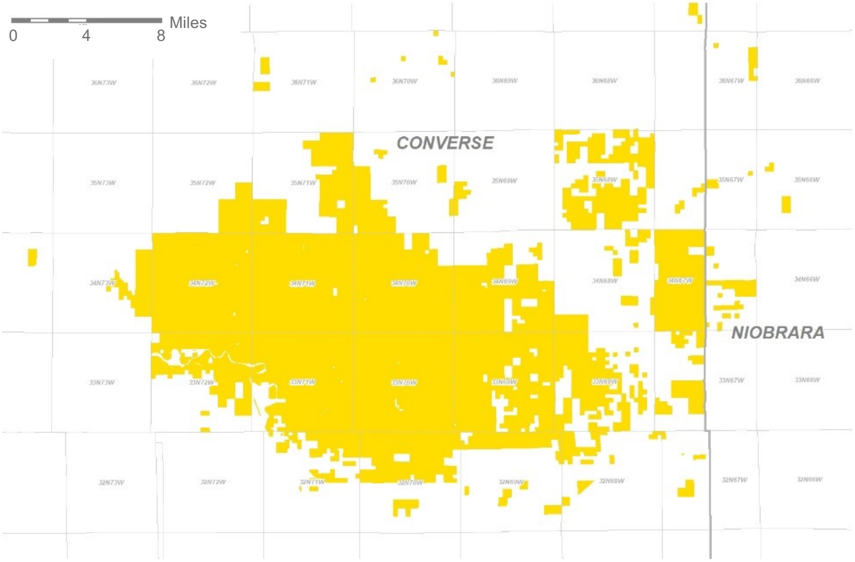
Powder River Basin: Overview

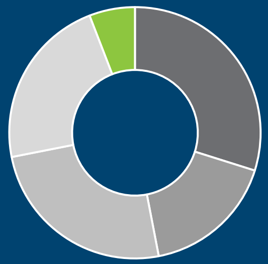




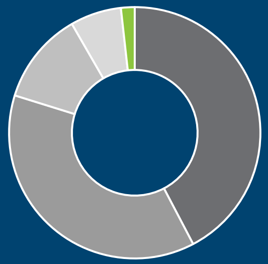
Acres	PDP Well Count	PDP Decline	1Q’21 Activity
~190,000 ~85,500 (Federal)	Op: 300	2020 TILs: 58%	Wells drilled: 0
~80% WI, 65% NRI	Non-Op: 40	Field: 18% (5-yr avg)	Wells TIL’d: 0

2021E Production Outlook

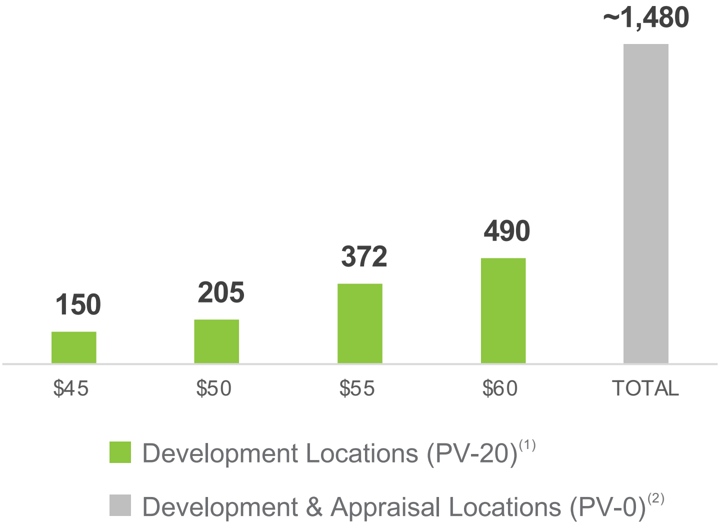
2021E EBITDAX Outlook



2021E Capital Plan



Appalachia Gulf Coast South Texas Brazos Valley Powder River Basin



(1) 20% ROR at current spacing assumption, proven development zones; Gas price held constant at $2.50 for location counts.
(2) Location counts do not include exploration wells or zones still in early evaluation.

Leading a Responsible Energy Future

Our path to achieving net-zero direct GHG emissions by 2035

Environmental Stewardship

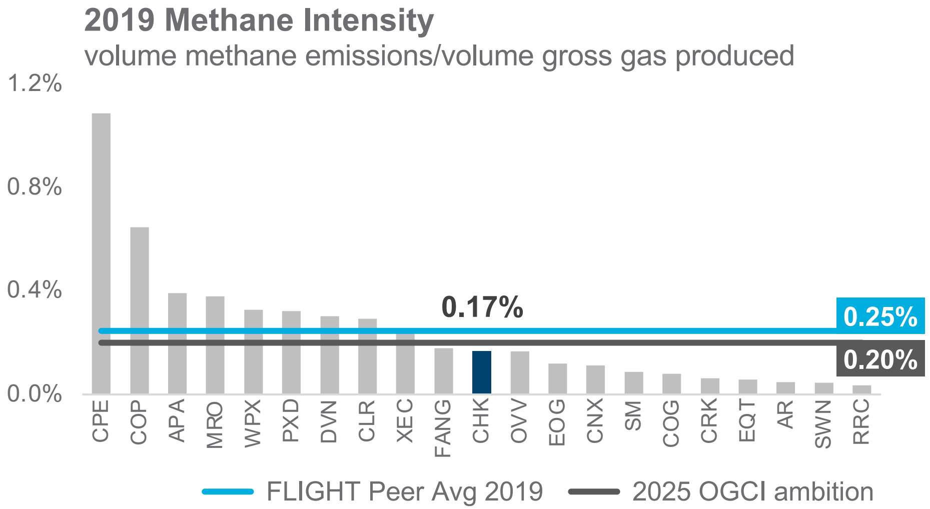
- Eliminate routine flaring on all wells completed from 2021 forward, and enterprise-wide targeted by 2025
- Targeted reduction of GHG intensity and methane intensity by 2025
- Intend to initiate first electric frac in 2021, opportunity to implement enterprise-wide

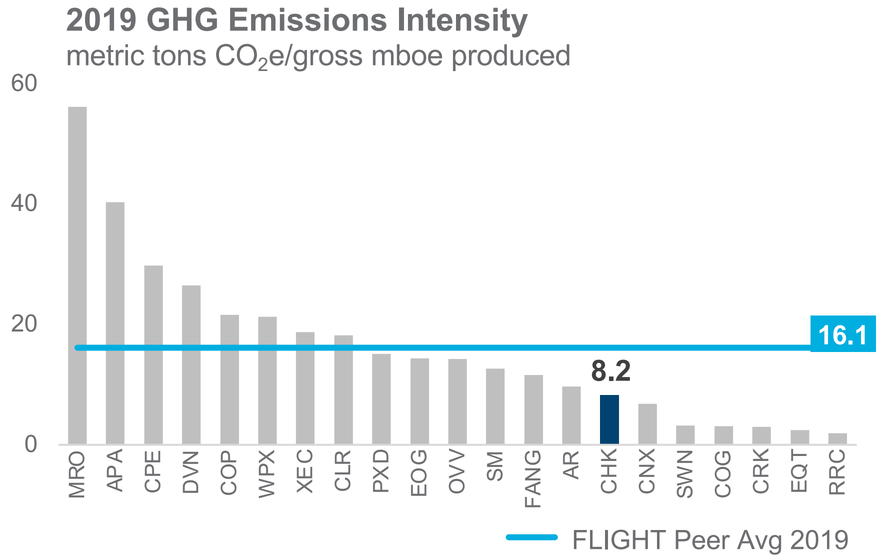
Social Engagement

- One CHK culture and company core values promote a diverse, inclusive and productive workplace
- Commitment to increased I&D education and training

Governance Reform

- Board committee dedicated to ESG oversight





Source: Company disclosure

CHK's RSG Pilot with Project Canary/IES TrustWell™

- Currently engaged with IES TrustWell™ (Project Canary) to conduct a pilot project on two pad locations in both the Haynesville and Appalachia Plays
  - To date, IES TrustWell™ has certified the majority of publicly-announced RSG transactions
- Achieving the Responsibly Sourced Gas (RSG) certification will allow us the opportunity to participate in an increasing trend of purchasers including certified gas in their RFP's (domestic and international)

> *"Chesapeake is an industry pioneer and top producer, and we're proud to help them reach the highest environmental standards."*
>
> *– Project Canary Co-founder and CEO*

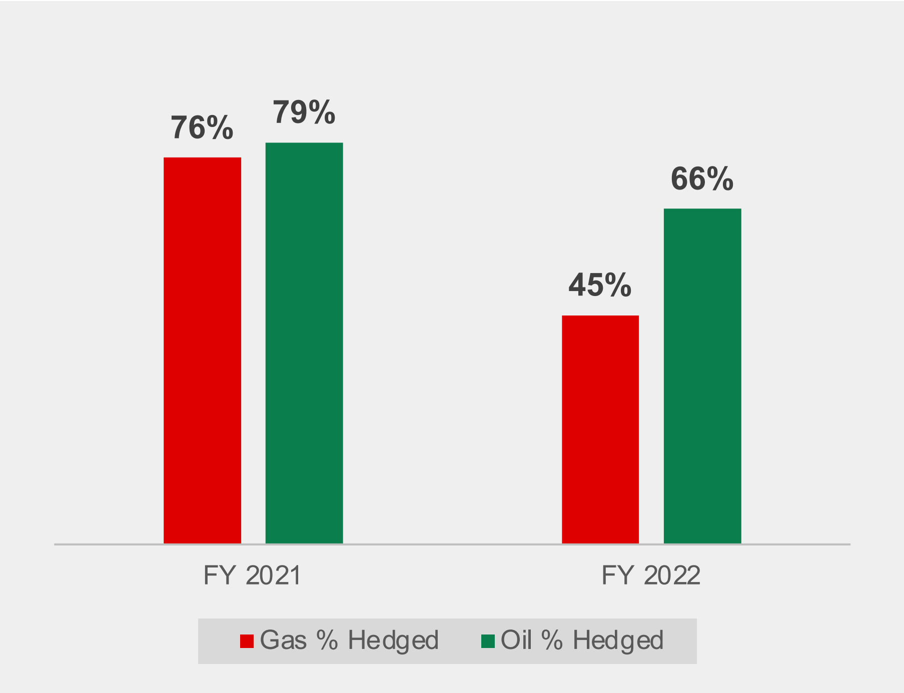
Project Canary

TrustWell™
IES
E&P Well
GOLD
2020

IES VERIFIED ATTRIBUTES
CH4 LOW-METHANE
FRESHWATER FRIENDLY
SAFE OPERATOR
CHEMICAL STEWARD

Appendix

Hedging Program Reduces Risk, Protects Returns



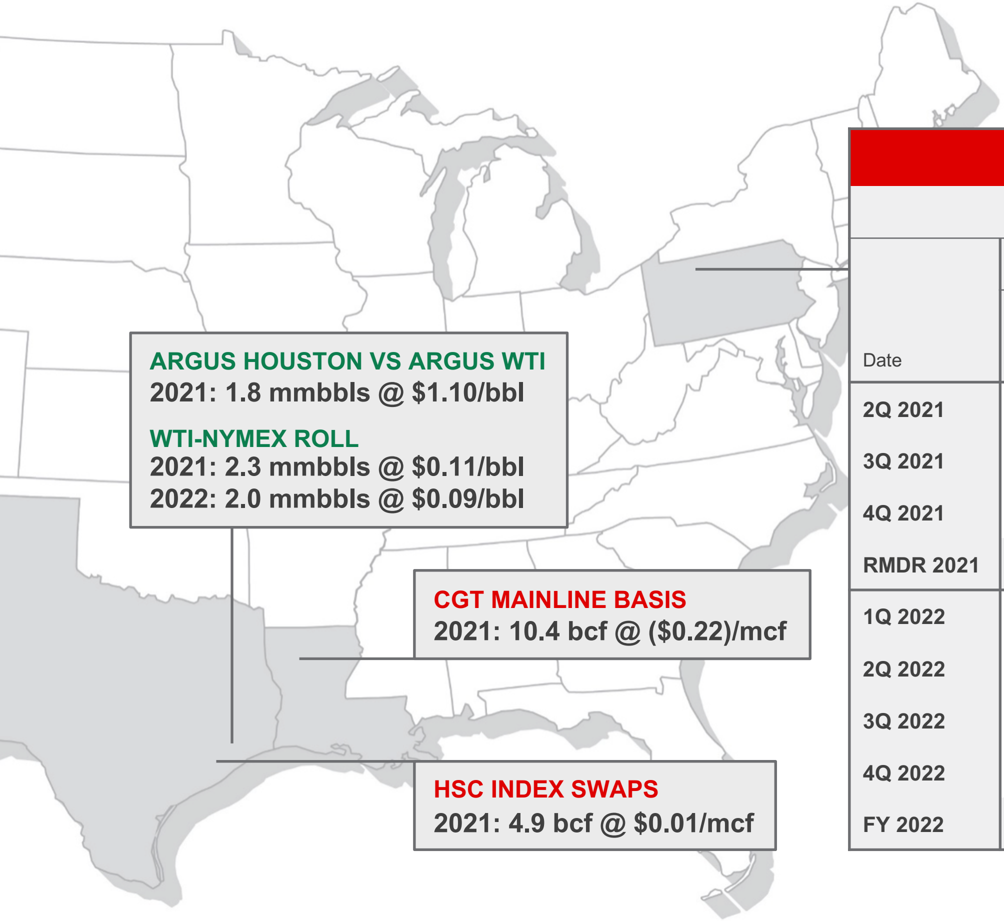
AVERAGE HEDGED PRICE FY	2021	2022
Gas ($/mcf)	$ 2.67	$ 2.52
Oil ($/bbl)	$ 42.62	$ 44.30

	NATURAL GAS					OIL	
	SWAPS		COLLARS			SWAPS	
Date	Volume bcf	Avg. Price $/mcf	Volume bcf	Avg. Put $/mcf	Avg. Call $/mcf	Volume mmbbl	Avg. Price $/bbl
2Q 2021	135.3	2.66	8.2	2.80	3.29	4.8	42.62
3Q 2021	126.6	2.66	8.3	2.80	3.29	4.6	42.62
4Q 2021	115.2	2.67	8.3	2.80	3.29	4.3	42.62
RMDR 2021	**377.1**	**2.66**	**24.8**	**2.80**	**3.29**	**13.7**	**42.62**
1Q 2022	77.7	2.55	18.0	2.50	2.86	3.2	43.57
2Q 2022	69.0	2.51	18.2	2.50	2.86	2.8	43.12
3Q 2022	66.8	2.55	18.4	2.50	2.86	2.7	44.85
4Q 2022	35.9	2.62	41.8	2.39	2.90	2.6	45.92
FY 2022	**249.5**	**2.55**	**96.4**	**2.45**	**2.88**	**11.2**	**44.30**

Note: Hedged volumes and prices reflect positions as of 4/30/2021, percentages are fixed price hedges vs. forecast volume. .

Hedged Basis Projection

As of 5/10/2021

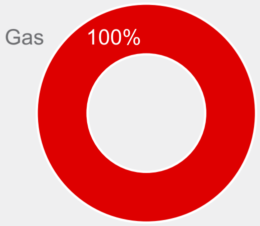


APPALACHIA NATURAL GAS HEDGES																		
	BASIS												TRANSPORT SPREAD[1]					
	TOTAL APPALACHIA			TETCO M3			TGP Z4 300L			LEIDY			TETCO M3			LEIDY		
Date	Volume bcf	% of Exposure	Avg. Price $/mcf	Volume bcf	% of Exposure	Avg. Price $/mcf	Volume bcf	% of Exposure	Avg. Price $/mcf	Volume bcf	% of Exposure	Avg. Price $/mcf	Volume bcf	% of Exposure	Avg. Price $/mcf	Volume bcf	% of Exposure	Avg. Price $/mcf
2Q 2021	37.6	33%	(0.84)	13.7	53%	(0.61)	16.4	36%	(0.98)	7.6	22%	(0.96)	–	–	–	2.3	7%	0.11
3Q 2021	43.2	37%	(0.88)	13.8	52%	(0.61)	18.2	40%	(0.99)	11.3	32%	(1.02)	–	–	–	2.3	7%	0.11
4Q 2021	25.9	23%	(0.58)	9.2	35%	(0.01)	10.1	23%	(0.89)	6.6	19%	(0.90)	5.4	20%	0.79	0.8	2%	0.11
RMDR 2021	**106.8**	**31%**	**(0.79)**	**36.7**	**46%**	**(0.46)**	**44.7**	**33%**	**(0.96)**	**25.4**	**25%**	**(0.97)**	**5.4**	**7%**	**0.79**	**5.4**	**5%**	**0.11**
1Q 2022	18.3	16%	(0.28)	6.8	26%	0.59	7.4	18%	(0.82)	4.1	12%	(0.74)	11.1	43%	0.79	–	–	–
2Q 2022	1.4	1%	(0.07)	1.4	5%	(0.07)	–	–	–	–	–	–	11.3	42%	0.79	–	–	–
3Q 2022	1.4	1%	(0.07)	1.4	5%	(0.07)	–	–	–	–	–	–	11.4	42%	0.79	–	–	–
4Q 2022	0.5	0%	(0.07)	0.5	2%	(0.07)	–	–	–	–	–	–	9.9	37%	0.77	–	–	–
FY 2022	**21.5**	**5%**	**(0.25)**	**10.0**	**9%**	**0.38**	**7.4**	**3%**	**(0.82)**	**4.1**	**6%**	**(0.74)**	**43.7**	**41%**	**0.78**	**–**	**–**	**–**

(1) Transport spread vs. TGP Z4 300L

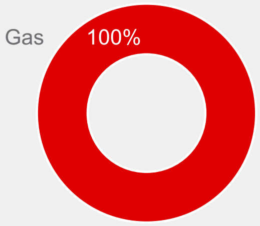
Gas Assets: Appalachia and Gulf Coast

1Q'21 Production:
1,261 mmcf/d



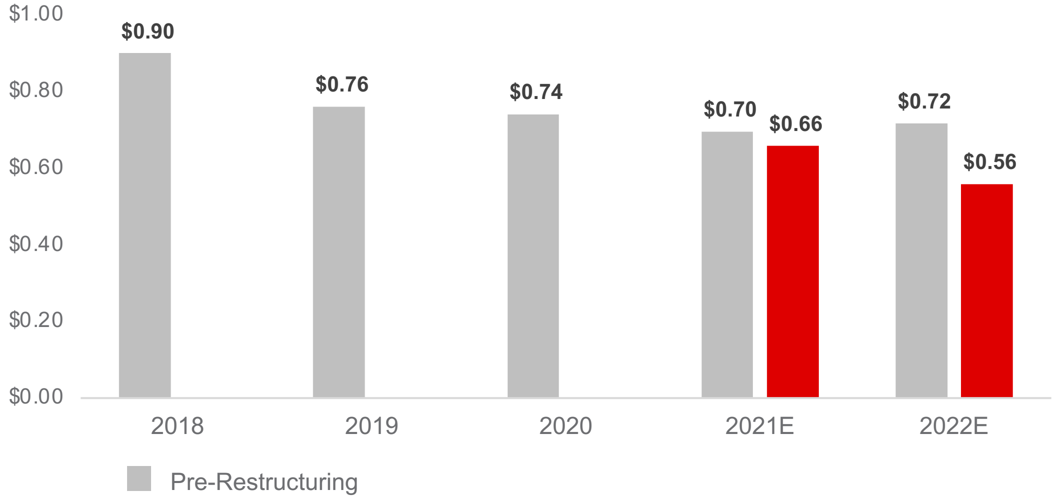
- ($0.50)/mcf annual average in-basin to NYMEX pricing
- Premium realizations in winter months

1Q'21 Production:
532 mmcf/d

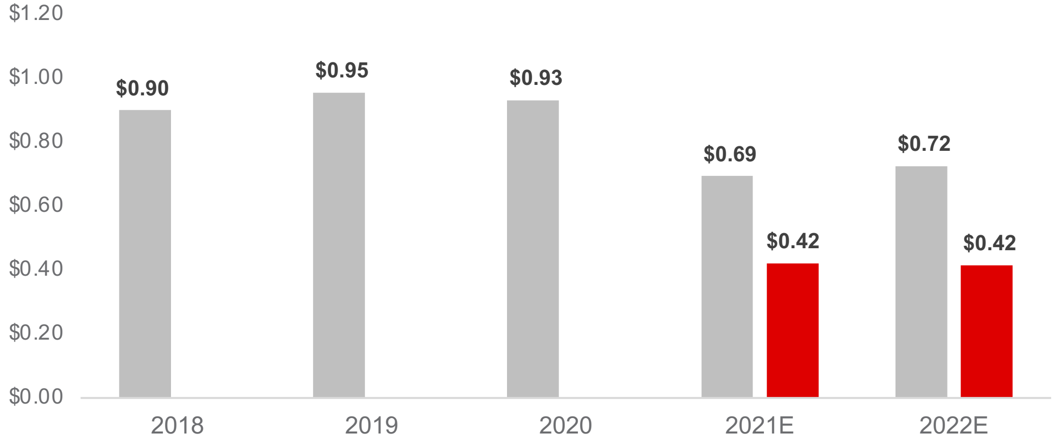


- ($0.18)/mcf annual average in-basin to NYMEX pricing

Appalachia: Gas GP&T ($/mcf)

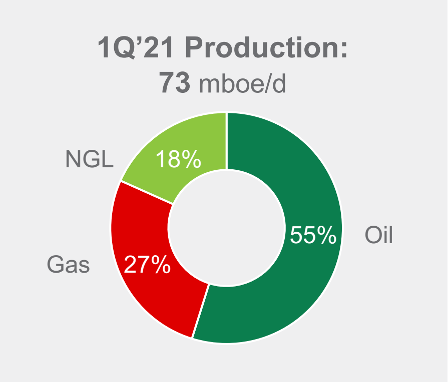


Gulf Coast: Gas GP&T ($/mcf)

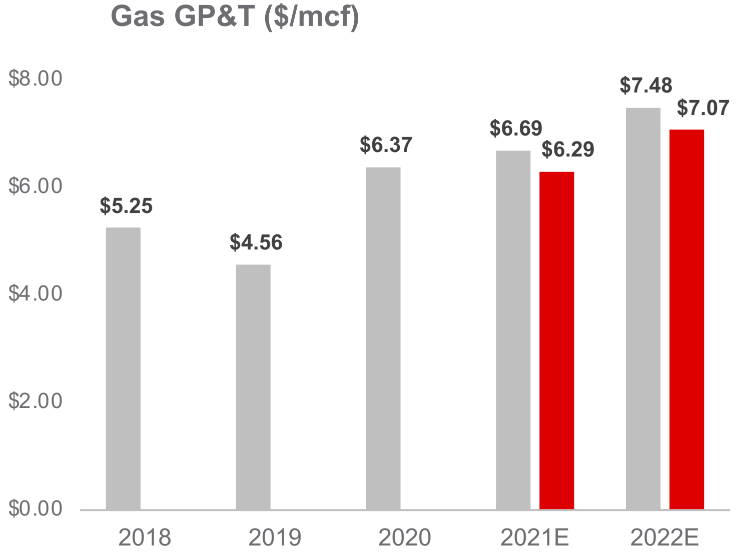


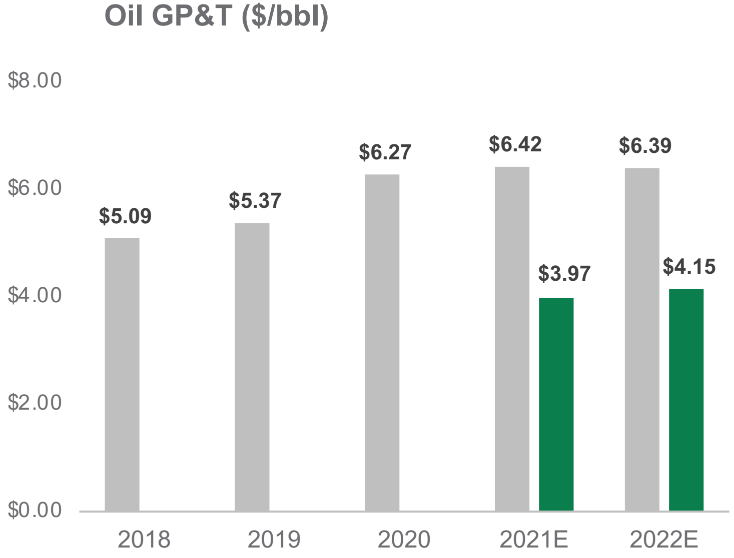
Marketing fee excluded. Basis based on periods 2021E – 2025E.

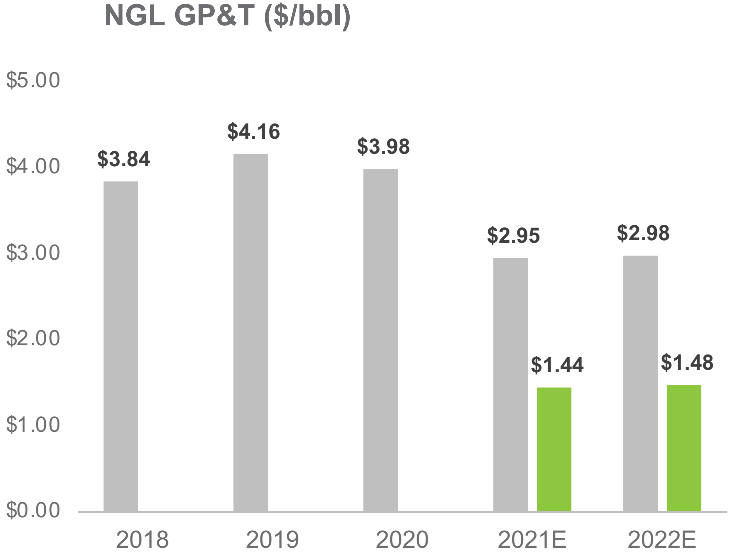
South Texas



- +$0.15/mcf, +$0.30/bbl oil, and +$0.15/bbl NGL annual average in-basin to NYMEX pricing
- Eliminated processing and crude MVCs, only gas gathering MVCs remain



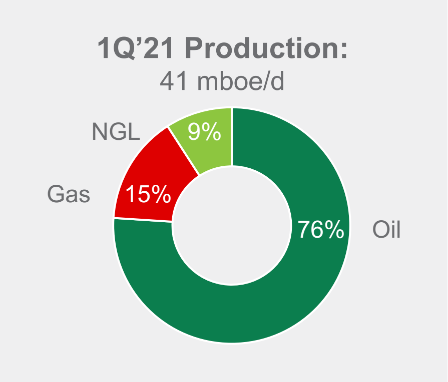




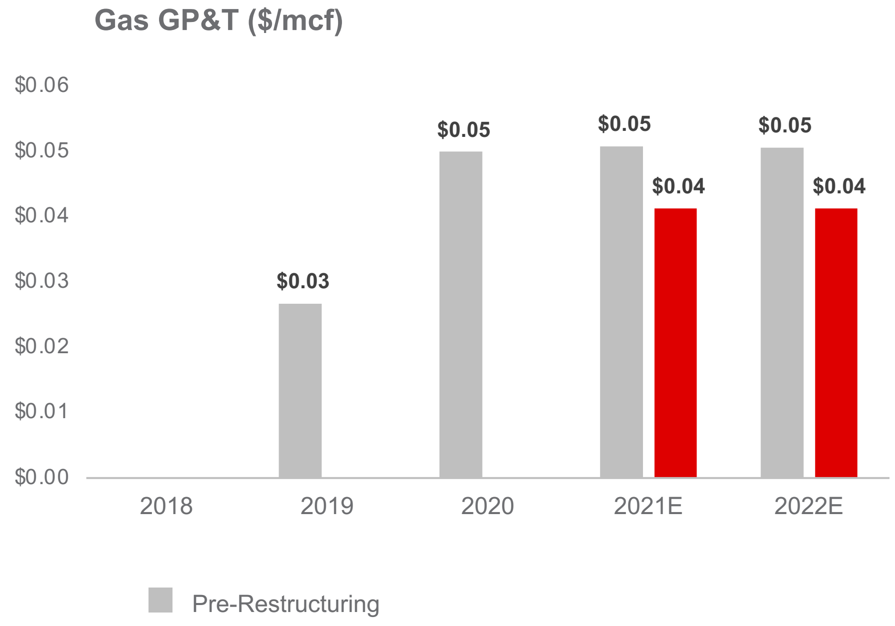
Pre-Restructuring

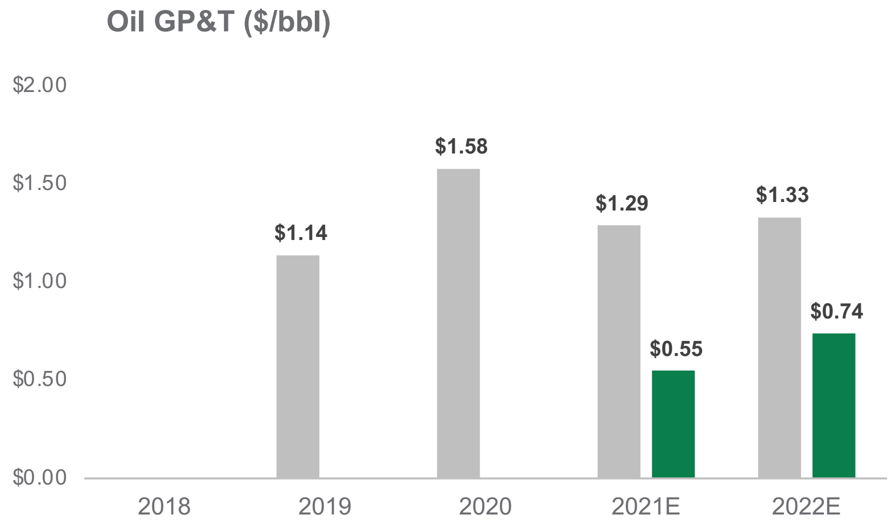
Marketing fee excluded. Basis based on periods 2021E – 2025E.

Brazos Valley



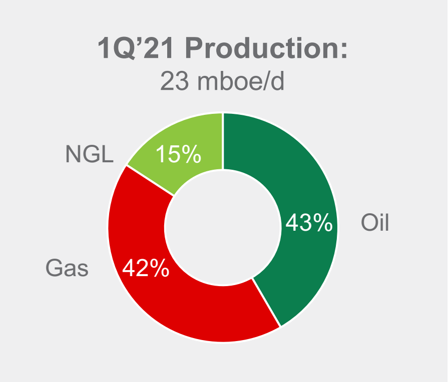
- ($0.50)/mcf, ($0.75)/bbl oil, and ($8.30)/bbl NGL annual average in-basin to NYMEX pricing
- Eliminated all MVCs



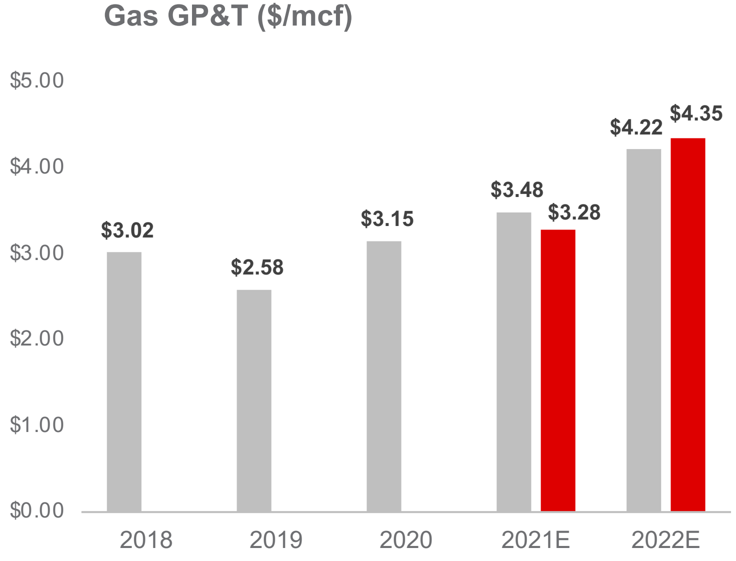


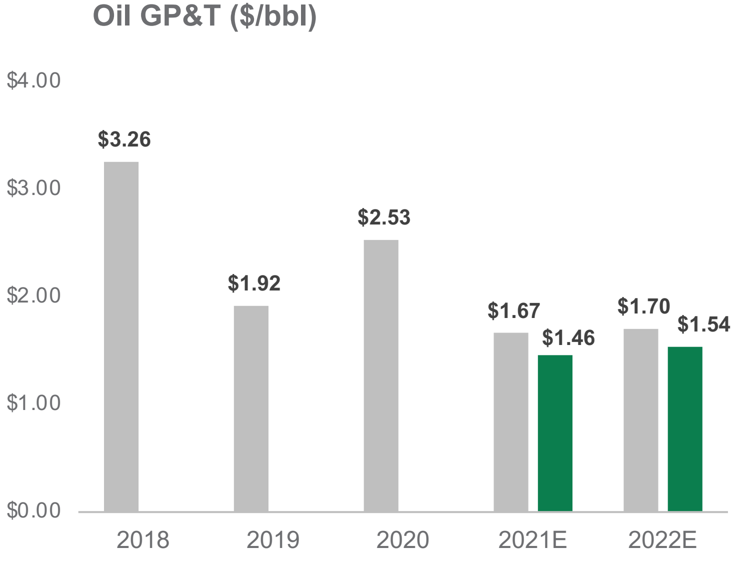
Marketing fee excluded. Basis based on periods 2021E – 2025E.

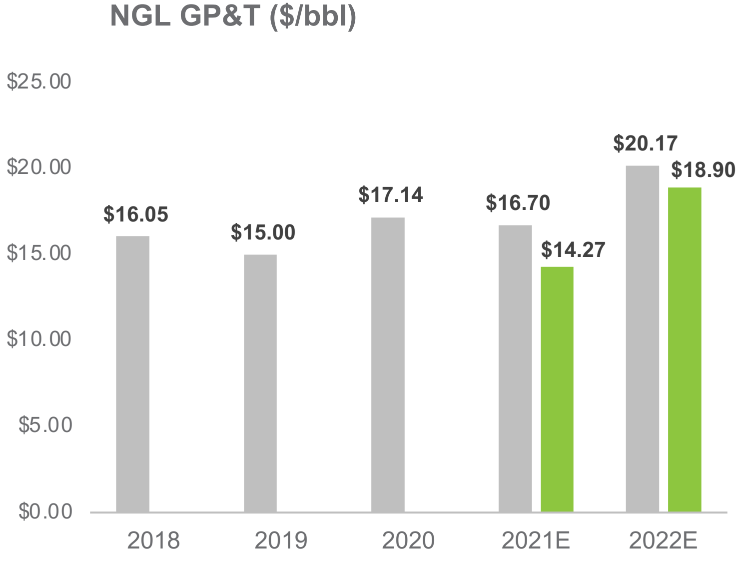
Powder River Basin



- ($0.05)/mcf, ($2.25)/bbl oil, and ($4.15)/bbl NGL annual average in-basin to NYMEX pricing
- MVC/EBITDAX recoupment converted to straight MVC, four years, 90% of PDP



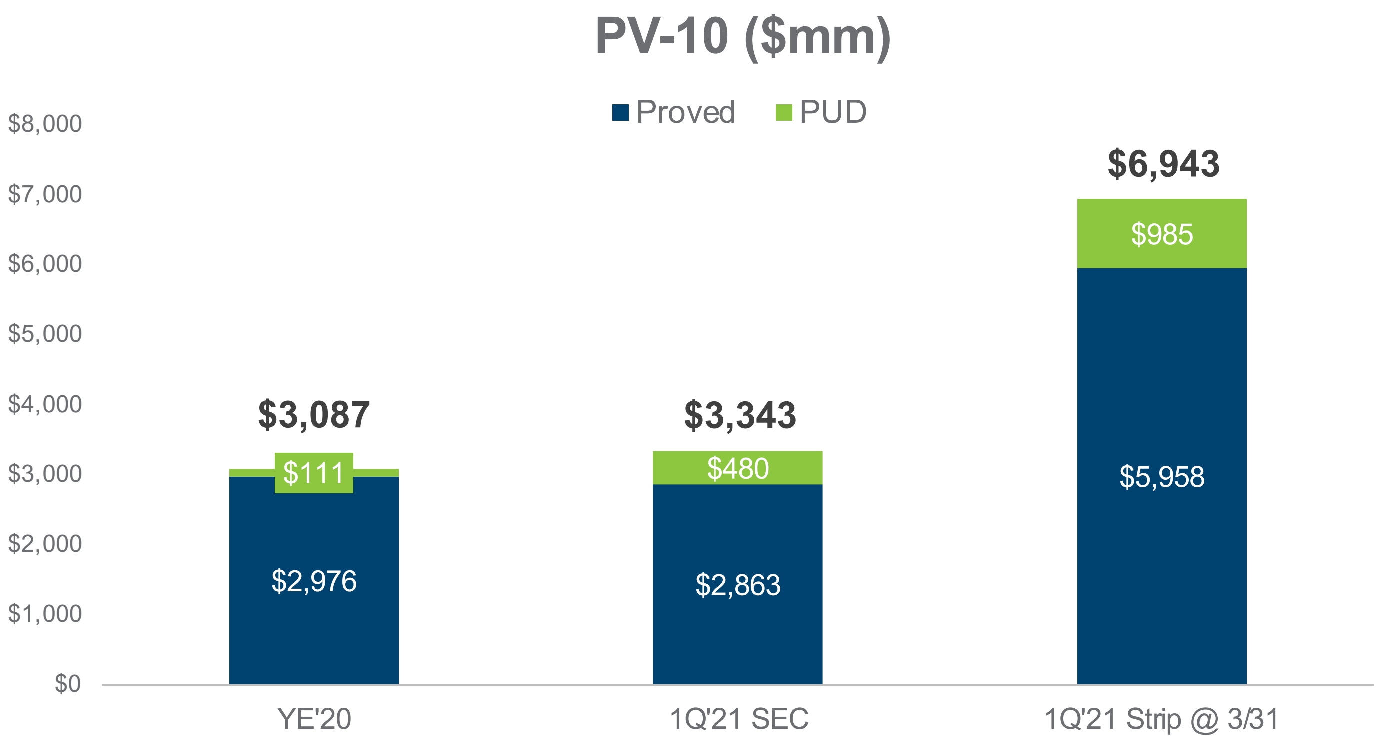


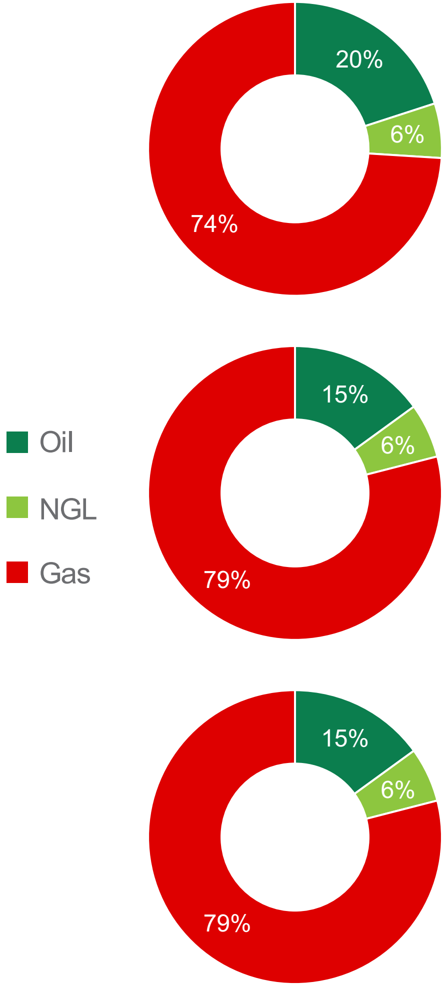


Pre-Restructuring

Marketing fee excluded. Basis based on periods 2021E – 2025E.

Reserves Update





YE'20 SEC
802 mmboe
7% PUD

1Q'21 SEC
1,099 mmboe
29% PUD

1Q'21 @ 3/31 Strip
1,127 mmboe
28% PUD

Note: Estimated proved reserves and PV-10 value for year-end 2020 were computed using first-day-of-the-month 12-month average prices of $39.57 per bbl of oil and $1.98 per mcf of natural gas, before basis differential adjustments. Comparable prices for first quarter 2021 were $40.01 per bbl and $2.16 per mcf. PV-10, a non-GAAP measure, is an estimated discounted net present value of proved reserves, before projected income taxes, using a 10% per annum discount rate and should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

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

	Successor	Predecessor	Non-GAAP Combined	Predecessor
	Period from February 10, 2021 through March 31, 2021	Period from January 1, 2021 through February 9, 2021	Three Months Ended March 31, 2021	Three Months Ended March 31, 2020
($ in millions)				
Net income (loss) (GAAP)	$ 295	$ 5,383	$ 5,678	$ (8,313)
Adjustments:				
Interest expense	12	11	23	145
Income tax benefit	—	(57)	(57)	(13)
Depreciation, depletion and amortization	122	72	194	603
Exploration	1	2	3	282
Unrealized (gains) losses on oil, natural gas and NGL derivatives	(113)	369	256	(729)
Separation and other termination costs	—	22	22	5
Gains on sales of assets	(4)	(5)	(9)	—
Other operating expense (income)	2	(12)	(10)	68
Impairments	—	—	—	8,522
Gains on purchases or exchanges of debt	—	—	—	(63)
Reorganization items, net	—	(5,569)	(5,569)	—
Other	(21)	—	(21)	23
Adjusted EBITDAX (Non-GAAP)	$ 294	$ 216	$ 510	$ 530

Adjusted EBITDAX is not a measure of financial performance under GAAP, and should not be considered as an alternative to, or more meaningful than, cash flow provided by operating activities 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 Free Cash Flow and Net Debt

FREE CASH FLOW

($ in millions)	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	Predecessor Three Months Ended March 31, 2020
Net cash provided by (used in) operating activities (GAAP)	$ 409	$ (21)	$ 388	$ 397
Cash paid for reorganization items, net	18	66	84	—
Capital expenditures	(77)	(66)	(143)	(518)
Free cash flow (Non-GAAP)	$ 350	$ (21)	$ 329	$ (121)

NET DEBT

($ in millions)	Successor March 31, 2020
Total debt (GAAP)	$ 1,262
Premiums and issuance costs on debt	(41)
Principal amount of debt	1,221
Cash and cash equivalents	(340)
Net debt (Non-GAAP)	$ 881

Management's Outlook as of May 11, 2021

	Year Ending 12/31/2021
Total production:	
Oil – mmbbls	23.0 – 25.0
NGL – mmbbls	6.5 – 8.5
Natural gas – bcf	715 – 735
Total daily rate – mboe per day	410 – 420
Estimated basis to NYMEX prices, based on 4/30/21 strip prices:	
Oil – $/bbl	($0.20) – ($0.60)
Natural gas – $/mcf	($0.40) – ($0.50)
NGL – realizations as a % of WTI	40% – 45%
Operating costs per boe of projected production:	
Production expense	$1.85 – $2.15
Gathering, processing and transportation expenses	$4.90 – $5.40
Oil – $/bbl	$2.65 – $2.85
Natural Gas – $/mcf	$0.90 – $1.00
Severance and ad valorem taxes	$0.90 – $1.10
General and administrative[a]	$0.85 – $1.15
Depreciation, depletion and amortization expense	$5.00 – $6.00
Marketing net margin and Other ($ in millions)	$0 – $10
Interest expense ($ in millions)[b]	$70 – $80
Cash taxes ($ in millions)	$0 – $20
Adjusted EBITDAX, based on 4/30/21 strip prices ($ in millions)[c]	$1,550 – $1,650
Total capital expenditures ($ in millions)	$670 – $740

(a) Includes ~$0.08/boe of expenses associated with stock-based compensation, which are recorded in general and administrative expenses in Chesapeake's Condensed Consolidated Statement of Operations.
(b) Includes ~$15 million of non-cash interest expense due to timing of interest payments in 2021.
(c) 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 to arrive at adjusted EBITDAX include interest expense, income taxes, and depreciation, depletion and amortization expense, exploration expense as well as one-time items or items whose timing or amount cannot be reasonably estimated.