4Q 2019 EARNINGS

February 26, 2020

CHESAPEAKE ENERGY

FORWARD-LOOKING STATEMENT

This presentation includes “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, cost-cutting measures, reductions in expenditures, proposed refinancing transactions, capital exchange transactions, asset divestitures, reductions in capital expenditures, operational efficiencies, production and well connection forecasts, estimates of operating costs, anticipated capital and operational efficiencies, planned development drilling and expected drilling cost reductions, expected lateral lengths of wells, anticipated timing and number of wells to be placed into production, expected oil growth trajectory, projected capital expenditures, projected cash flow and liquidity, our ability to enhance our cash flow and financial flexibility, plans and objectives for future operations, 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 the forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate or changed assumptions or by known or unknown risks and uncertainties.

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 our ability to comply with the covenants under our revolving credit facilities and other indebtedness, 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 finance reserve replacement costs or satisfy our debt obligations; downgrade in our credit rating requiring us to post more collateral under certain commercial arrangements; 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 and in connection with our ongoing actions to reduce financial leverage and complexity; drilling and operating risks and resulting liabilities; effects of environmental protection laws and regulation 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; an interruption in operations at our headquarters due to a catastrophic event; certain anti-takeover provisions that affect shareholder rights; and our inability to increase or maintain our liquidity through debt repurchases, capital exchanges, asset sales, joint ventures, farmouts or other means.

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. Expected asset sales may not be completed in the time frame anticipated or at all. We caution you not to place undue reliance on our forward-looking statements, which speak only as of the date of this presentation, and we undertake no obligation to update any of the information provided in 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.

BUSINESS STRATEGY

Remains Unchanged, Resilient to Commodity Price Volatility

- Financial discipline
- Profitable and efficient growth from captured resources
- Exploration
- Business development

STRATEGIC GOALS

- Margin enhancement
- Free cash flow
- Net debt to EBITDAX of 2X
- Excellence in HSER

BUILDING THE FOUNDATION FOR FREE CASH FLOW

2019 ACCOMPLISHMENTS

- Grew oil production **~30%** yoy
- Increased adjusted EBITDAX margin per boe **14%** yoy
- Principal debt removed in debt exchange **$900mm** in 4Q'19
- Total production mix **26%** oil
- Reduced G&A and GP&T **$336mm** yoy
- Since 2014, generated highest adjusted **EBITDAX** per boe

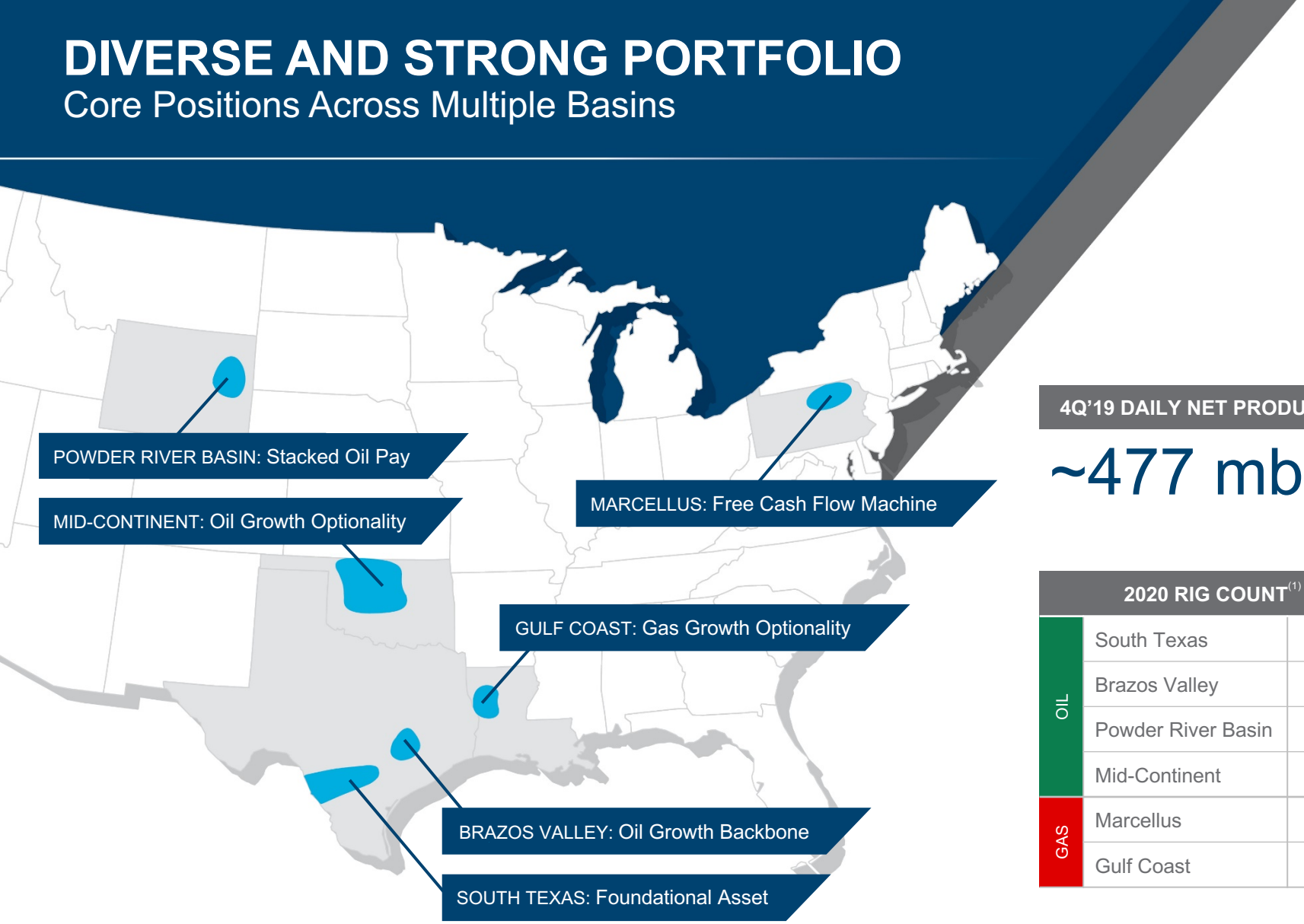
2020 PRIORITIES

Targeting free cash flow

- Reducing capex budget **~30%** yoy
- Reducing LOE and G&A **>10%** yoy
- Continuing to recognize capital efficiency improvements
- Funding 2020 debt maturities and enhancing liquidity through **$300 – $500mm** in expected non-core asset sales

DIVERSE AND STRONG PORTFOLIO

Core Positions Across Multiple Basins



4Q'19 DAILY NET PRODUCTION

~477 mboe

2020 RIG COUNT[1]		
OIL	South Texas	3 – 4
	Brazos Valley	2 – 3
	Powder River Basin	2 – 3
	Mid-Continent	~1
GAS	Marcellus	2 – 3
	Gulf Coast	~1

(1) Based on 2/26/20 Outlook

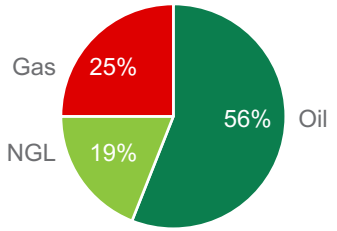
SOUTH TEXAS
Foundational Asset

- Generated over $300mm in free cash flow in 2019[1]
- Base optimization efforts yielded 1.8mm additional barrels of oil in 2019
- ~10% reduction in D&C capex per well year over year

OVERVIEW	
4Q'19 Production	104 mboe/d[2]
Net Acres	~232,000

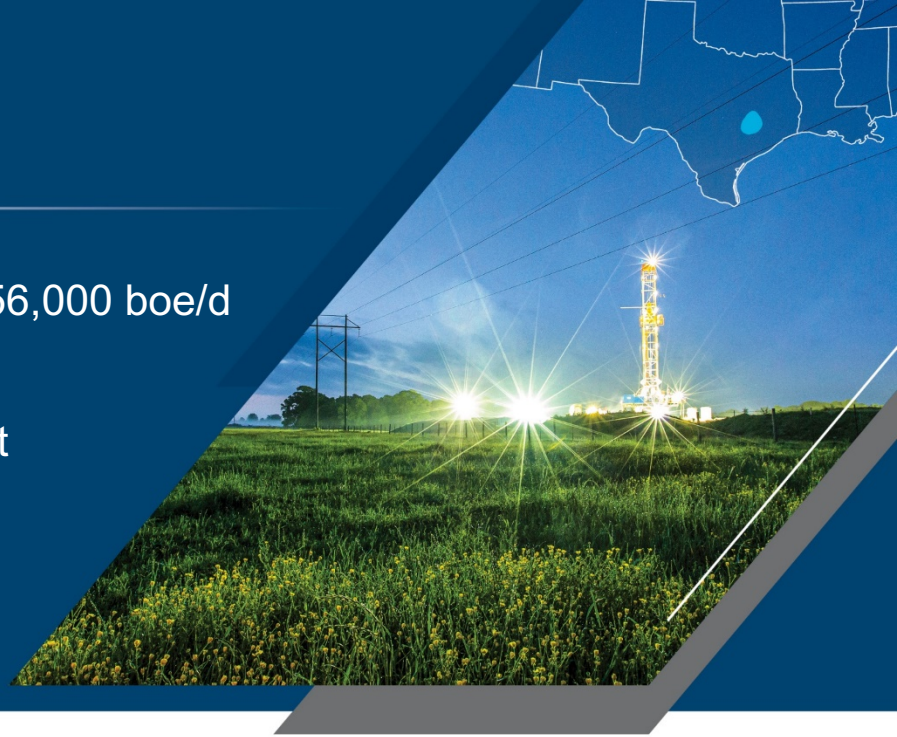
2020 ACTIVITY[3]	
Wells to Turn in Line	110 – 120
Rigs	3 – 4
Frac Crews	~2
Total Capex (mm)	$400 – $475

2020 PRODUCTION MIX[3]



(1) Free cash flow defined as net revenue less all operating costs and capital expenditures, excluding general and administrative and interest expenses
(2) Represents average net production volumes for 4Q'19
(3) Based on 2/26/20 Outlook

BRAZOS VALLEY
Oil Growth Backbone

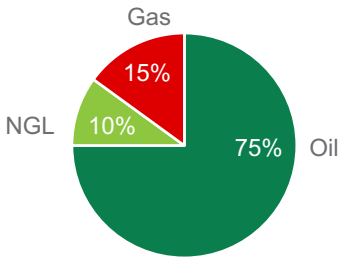


- Established field net oil production record of ~56,000 boe/d including ~40,000 bo/d in 4Q
- Recognized >35% year over year improvement in peak oil rates(1)
- Realized ~$250mm in cost savings and revenue improvements year over year(1)

OVERVIEW	
4Q'19 Production	56 mboe/d(2)
Net Acres	~477,000

2020 ACTIVITY(3)	
Wells to Turn in Line	55 – 65
Rigs	2 – 3
Frac Crews	~2
Total Capex (mm)	$500 – $600

2020 PRODUCTION MIX(3)



(1) Data compared to 2018 WRD results
(2) Represents average net production volumes for 4Q'19
(3) Based on 2/26/20 Outlook

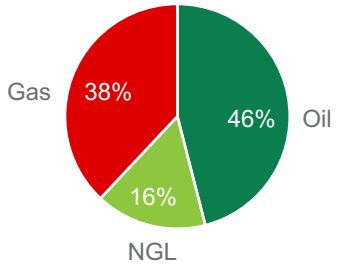
POWDER RIVER BASIN
Stacked Oil Pay

- Averaged ~21,000 bo/d in December 2019
- Four Niobrara wells turned to sales averaging 24-hour peak production rates of >2,000 boe/d (~1,200 bo/d)
- GP&T declined ~23% in 2019 and is expected to decrease another 7% to ~$8.70/boe in 2020

OVERVIEW	
4Q'19 Production	38 mboe/d[(1)]
Net Acres	~206,000

2020 ACTIVITY[(2)]	
Wells to Turn in Line	25 – 30
Rigs	2 – 3
Frac Crews	~1
Total Capex (mm)	$160 – $215

2020 PRODUCTION MIX[(2)]



(1) Represents average net production volumes for 4Q'19
(2) Based on 2/26/20 Outlook

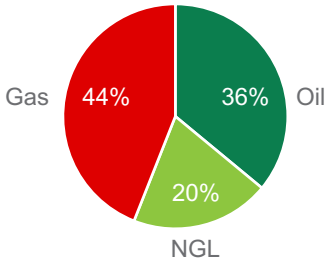
MID-CONTINENT
Oil Growth Optionality

- Generated over $20mm in free cash flow in 2019[1]
- High-grading 2020 and 2021 program
- Integrating new 3D data and recent appraisal program results

OVERVIEW	
4Q'19 Production	14 mboe/d[2]
Net Acres	~736,000

2020 ACTIVITY[3]	
Wells to Turn in Line	10 – 15
Rigs	~1
Frac Crews	~1
Total Capex (mm)	$35 – $50

2020 PRODUCTION MIX[3]



(1) Free cash flow defined as net revenue less all operating costs and capital expenditures, excluding general and administrative and interest expenses
(2) Represents average net production volumes for 4Q'19
(3) Based on 2/26/20 Outlook

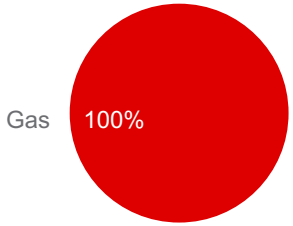
MARCELLUS
Free Cash Flow Machine

- Generated ~$320mm in free cash flow in 2019[1]
- 10 years of drilling inventory at $1.50 – $1.75/mcf break-even[2]
- Set daily gross field production record of 2.67 bcf/d in November 2019

OVERVIEW	
4Q'19 Production	980 mmcf/d[3]
Net Acres	~538,000

2020 ACTIVITY[4]	
Wells to Turn in Line	50 – 55
Rigs	2 – 3
Frac Crews	~1
Total Capex (mm)	$175 – $215

2020 PRODUCTION MIX[4]



(1) Free cash flow defined as net revenue less all operating costs and capital expenditures, excluding general and administrative and interest expenses
(2) Assumes current drilling activity level
(3) Represents average net production volumes for 4Q'19
(4) Based on 2/26/20 Outlook

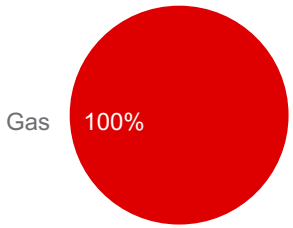
GULF COAST
Gas Growth Optionality

- Generated ~$150mm in free cash flow in 2019[(1)]
- Access to premium markets
- Base optimization yielding significant results

OVERVIEW	
4Q'19 Production	605 mmcf/d[(2)]
Net Acres	~293,000

2020 ACTIVITY[(3)]	
Wells to Turn in Line	5 – 10
Rigs	~1
Frac Crews	~1
Total Capex (mm)	$30 – $45

2020 PRODUCTION MIX[(3)]



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(2) Represents average net production volumes for 4Q'19
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FUELING A RESPONSIBLE ENERGY FUTURE
Focused on ESG Excellence

Environmental

Leading Emissions Management

- Reported 2018 methane loss rate of 0.14% – well below Oil and Gas Climate Initiative target of <0.25% by 2025[(1)]
- Environmental engineering integrated with facility engineering to maintain strong emissions management and reduction practices

Social

People Focused, Performance Driven

- Safety – more than a company metric – is a value that drives our commitment to responsible operations
- One CHK culture promotes a diverse, inclusive and productive workplace
- In 2019, Doug Lawler was the first E&P CEO to sign the pledge to advance diversity and inclusion in the workplace through the CEO Action for Diversity & Inclusion™

Governance

A Focus on Accountability

- Board and executive-level oversight of risk, climate and ESG initiatives
- ESG Advisory Group made up of senior leaders provides direction and leadership on ESG matters that influence our operations, our strategy and our business performance

(1) Methane loss rate based upon Subpart W reported values for tonne methane and tonne gas produced; 2019 number will be released 2Q'20

HEDGE POSITION
As of 2/26/2020

WEIGHTED AVERAGE PRICE

OIL	Volume (mmbbl)	Hedged %	Fixed	Call ($ per bbl)	Put Bought	Put Sold
Swaps:						
2020	30.3	72%	$59.59			
Collars:						
2020	1.8	4%		$83.25	$65.00	
Total 2020	**32.1**	**76%**				

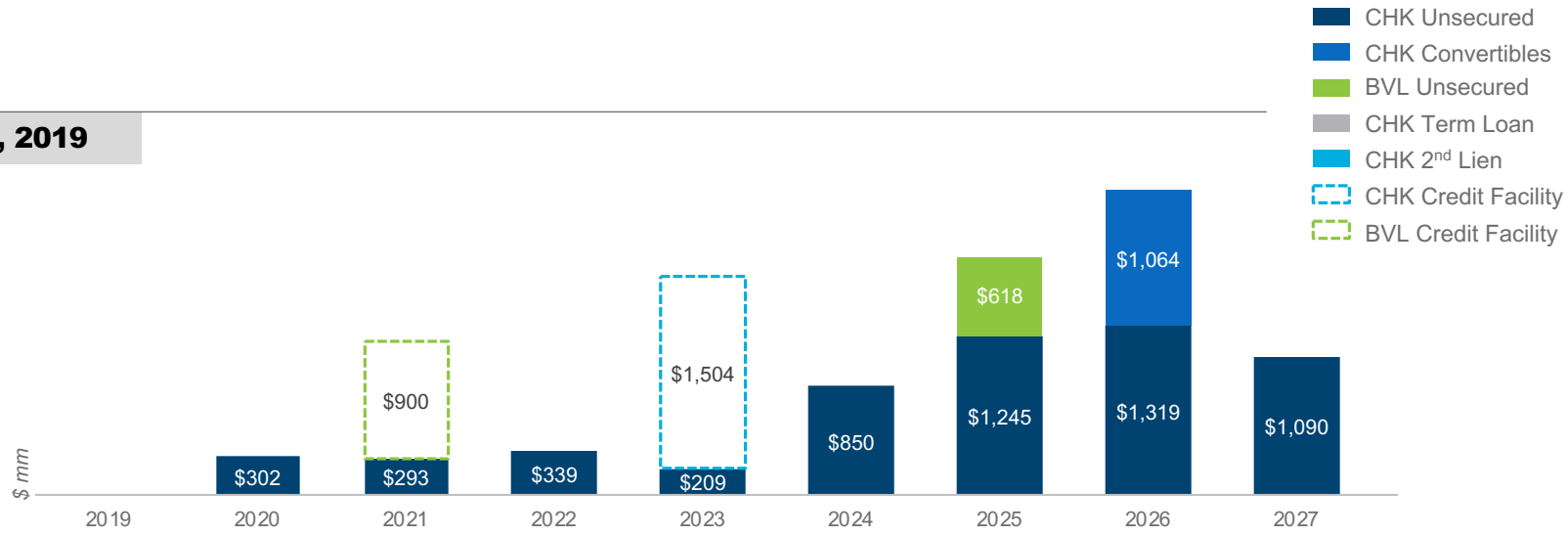
NATURAL GAS	Volume (bcf)	Hedged %	Fixed	Call ($ per mcf)	Put Bought	Put Sold
Swaps:						
2020	264.7	39%	$2.76			
Put Spread:						
2020	94.2	14%			$2.05	$1.80
Swaptions:						
2021	14.6			$2.80		
2022	14.6			$2.80		
Total 2020	**264.7**	**53%**				

2020 BASIS HEDGES	
Argus Houston vs Argus WTI	8.4 mmbbls @ $2.49 / bbl
CIG	2.7 bcf @ ($0.50) / mcf
HSC	46.7 bcf @ ($0.07) / mcf
TETCO M3	4.1 bcf @ $1.47 / mcf

Includes January and February 2020 derivative contracts that have settled

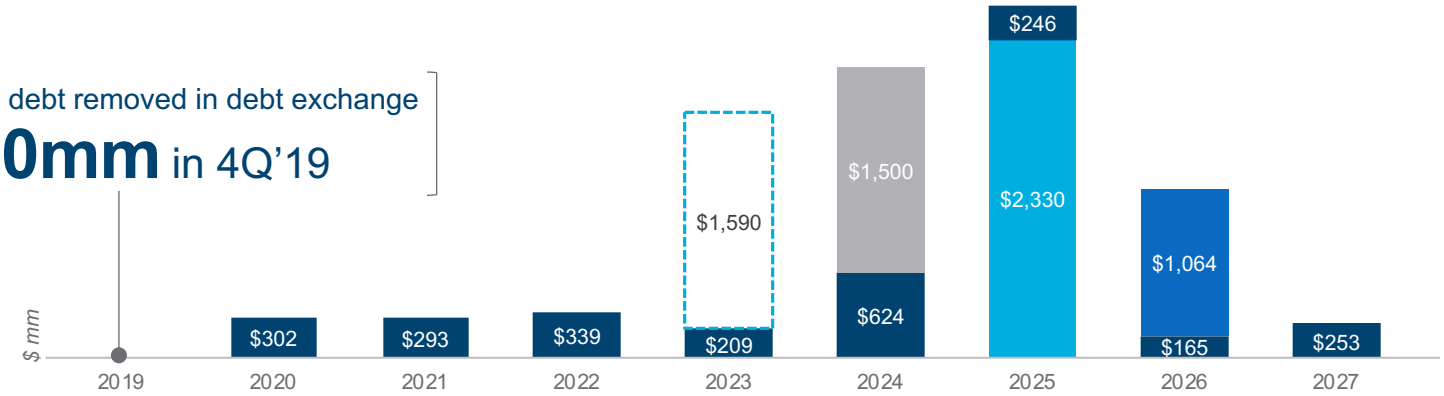
PRUDENTLY MANAGING OUR MATURITIES

SEPT. 30, 2019



DEC. 31, 2019

Principal debt removed in debt exchange
$900mm in 4Q'19



CORPORATE INFORMATION

HEADQUARTERS

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Vice President – Investor Relations and Communications

DOMENIC J. DELL'OSSO, JR.
Executive Vice President and Chief Financial Officer

Investor Relations department can be reached at ir@chk.com

CHK
LISTED
NYSE

PUBLICLY TRADED SECURITIES	CUSIP	TICKER
6.625% Senior Notes due 2020	#165167CF2	CHK20A
6.875% Senior Notes due 2020	#165167BU0 #165167BT3 #U16450AQ8	CHK20
6.125% Senior Notes Due 2021	#165167CG0	CHK21
5.375% Senior Notes Due 2021	#165167CK1	CHK21A
4.875% Senior Notes Due 2022	#165167CN5	CHK22
5.75% Senior Notes Due 2023	#165167CL9	CHK23
7.00% Senior Notes due 2024	#165167DA2	N/A
Term Loan Due 2024	#16516FAG4	N/A
8.00% Senior Notes due 2025	#165167CT2 #165167CU9 #U16450AU9	N/A
11.5% Senior Secured Second Lien Notes due 2025	#U16450AZ8 #165167DD6	N/A
7.50% Senior Notes due 2026	#165167DB0	N/A
8.00% Senior Notes due 2026	#165167DC8 #U16450AY1	N/A
5.50% Contingent Convertible Senior Notes due 2026	#165167CY1	N/A
8.00% Senior Notes due 2027	#165167CV7 #U16450AV7	N/A
4.5% Cumulative Convertible Preferred Stock	#165167842	CHK PrD
5.0% Cumulative Convertible Preferred Stock (Series 2005B)	#165167834 #165167826	N/A
5.75% Cumulative Convertible Preferred Stock	#U16450204 #165167776 #165167768	N/A
5.75% Cumulative Convertible Preferred Stock (Series A)	#U16450113 #165167784 #165167750	N/A
Chesapeake Common Stock	#165167107	CHK

As of 2/26/20