FORWARD-LOOKING STATEMENTS

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, guidance or forecasts of future events, production and well connection forecasts, estimates of operating costs, anticipated capital and operational efficiencies, planned development drilling and expected drilling cost reductions, general and administrative expenses, capital expenditures, the timing of anticipated asset sales and proceeds to be received therefrom, projected cash flow and liquidity, our ability to enhance our cash flow and financial flexibility, plans and objectives for future operations, 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: 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; 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/or cyber-attacks adversely impacting our operations; potential challenges by SSE’s former creditors of our spin-off of in connection with SSE’s recently completed bankruptcy under Chapter 11 of the U.S. Bankruptcy Code; an interruption in operations at our headquarters due to a catastrophic event; the continuation of suspended dividend payments on our common stock; the effectiveness of our remediation plan for a material weakness; 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 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.

We use certain terms in this presentation such as “Resource Potential,” “Net Reserves” and similar terms that the SEC’s guidelines strictly prohibit us from including in filings with the SEC. These terms include reserves with substantially less certainty, and no discount or other adjustment is included in the presentation of such reserve numbers. U.S. investors are urged to consider closely the disclosure in our Form 10-K for the year ended December 31, 2016, File No. 1-13726 and in our other filings with the SEC, available from us at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118. These forms can also be obtained from the SEC by calling 1-800-SEC-0330.
**OUR STRATEGY**
STRONG THROUGH COMMODITY PRICE CYCLES

**BUSINESS STRATEGIES:**

- Financial Discipline
- Business Development
- Profitable and Efficient Growth from Captured Resources
- Exploration

**2018 Priorities**

- Focused on cash flow neutrality
- Retain posture for growth
- $2 – $3 billion of asset sales
- Capital allocation focused on portfolio expansion optionality
WE’VE MADE SIGNIFICANT PROGRESS
DURING LOW AND VOLATILE COMMODITY PRICES OF 2016 – 2017

- ~$3.1 billion of net proceeds from asset sales
- Removed or extended more than $3.5 billion in 2017 – 2019 maturities, $432mm remain for this period
- Barnett and Devonian Shale exits greatly improve operating margin
- Reaffirmed revolving credit facility with borrowing base of ~$3.8 billion
- Removed ~$580mm in midstream commitments and renegotiated PRB contract
- Five VPPs eliminated
- Reduced legal obligations
OPERATIONAL MOMENTUM BUILDING INTO 2018

Results from pushing technology across the portfolio

Marcellus McGavin 6H ~61 mmcf/d
PRB Rankin 1H ~2,800 boe/d
STX Blakeway 2H ~3,200 boe/d

Enhancing our oil assets

Drilling longer laterals
Enhanced completion designs
Testing spacing assumptions

Driving value over volumes

Capital efficiencies continue to improve across all assets

Note: As of 11/2/17, using midpoints for 2017 total production and capital expenditures from 11/2/2017 Outlook.
South Texas

- Oil production growth engine
- Longer laterals driving value
- Enhanced completions yielding encouraging results

2017 CAPITAL ALLOCATION
FLEXIBLE PROGRAM – VALUE FOCUSED

Eagle Ford Shale
5 Rigs / 5 Frac Crews
Breakeven <$40/bbl

Breakeven is PV10 with oil held flat at $50/bbl and gas held flat at $3/mcf
Large remaining potential
Estimated net resources of > 2.0 bboe

Oil growth engine
~10% oil volume growth 4Q’16 vs. 4Q’17

Capital efficiency improves
Faster cycle times, longer laterals

(1) F&D Costs referenced in this chart are net capital costs divided by net EUR per well. Wells are binned by year in which they were TIL’d and then were averaged across that year.
Notable performance
Vesper Unit IV DIM H 3H
TIL 10/06/2017 – 16,194’ lateral

- Peak rate – 2,350 bo/d, 2,580 boe/d
- Longer laterals are paying off
- Enhanced completions are leading to improved well results
2017 CAPITAL ALLOCATION
FLEXIBLE PROGRAM – VALUE FOCUSED

Gulf Coast

Haynesville Shale
3 Rigs / 1 Frac Crew
Breakeven ~$2.50/mcf

> Longer laterals creating greater value
> Refracs improve capital efficiency
> Bossier resource potential

(1) Breakeven is PV10 with oil held flat at $50/bbl and gas held flat at $3/mcf
GULF COAST
PIONEERS WITH A COMPETITIVE ADVANTAGE

Average Cumulative Gas per Well

Month

2008 – 2013
HBP Position

2014 – 2015
Develop Core Position

2016
Longer Laterals, Enhanced Completions, Increased IP’s

2017
Area Specific Completions, Improved Capital Efficiency, Optimized Drawdown

More to Do…
2017 CAPITAL ALLOCATION
FLEXIBLE PROGRAM – VALUE FOCUSED

Appalachia
2 Rigs / 2 Frac Crews
Marcellus Breakeven ~$2.10/mcf (1)
Utica Dry Breakeven ~$2.50/mcf (1)

Appalachia
> Optimizing stimulation designs
> Utica oil growth
> Significant resource potential

(1) Breakeven is PV10 with oil held flat at $50/bbl and gas held flat at $3/mcf
**Resource potential**
Maris pad – two Upper Marcellus wells
60 mmcf/d combined peak flow rate
TIL 9/01/2017, ~6,700' avg. lateral

**Upper Marcellus**
Co-development with running room
Optimizing future plans with 10,000' laterals
~750 potential locations\(^{(1)}\)

**Utica appraisal**
Core planned for 2018
~70,000 net perspective acres

---

\(^{(1)}\) Upper Marcellus development assumes 1,200' spacing
Tight Cluster Spacing

20 – 45% uplift in wet gas
30 – 50% uplift in dry gas

Slickwater Completions

20 – 25% uplift in wet gas areas
25% increase in 120 day cumulative volume (1)

Impact of 2017 TILs

Wet Gas

Cumulative Volume, (mboe)

Producing Days

Enhanced Completions
Type Curve
Base Design

Impact of Tighter Cluster Spacing

Wet Gas

Cumulative Volume, (bcfe)

Producing Days

30 ft Cluster Spacing
55 ft Cluster Spacing
Type Curve

(1) Results for 2017 TILs through September 2017
2017 CAPITAL ALLOCATION
FLEXIBLE PROGRAM – VALUE FOCUSED

Mid-Continent
1 Rig / 1 Frac Crew
Breakeven ~$40/bbl

(1) Breakeven is PV10 with oil held flat at $50/bbl and gas held flat at $3/mcf
Portfolio changes
Raised $1.2B in proceeds
Sold ~1.1mm net acres
Sold ~4,000 operated wells
Sold ~7,000 non-operated wells

Portfolio status
Acreage: 975k net acres (97% HBP)
Operated well count: 3,200 producing wells
Non-Operated well count: 4,200 producing wells
Net Production: 55 mboe/d (30% oil)

Forward plan
> Development – Oswego
> Appraisal – 15+ zones in the Wedge
> Base Optimization – Field production focus
2017 CAPITAL ALLOCATION
FLEXIBLE PROGRAM – VALUE FOCUSED

Powder River Basin
3 Rigs / 1 Frac Crew
Breakeven <$40/bbl (1)

NOVEMBER 2017 UPDATE

Powder River Basin

> Hotspot advantage
> Stacked pay opportunities
> Significant resource potential

(1) Breakeven is PV10 with oil held flat at $50/bbl and gas held flat at $3/mcf
290,000 NET ACRES OF GROWTH POTENTIAL

- ~700,000 acres of stacked potential
- ~90% undeveloped
- 98% of leases cover all depths
- Focused on 9 operated federal units
  > Single-operator control
  > Minimal drilling obligations
  > Long-lateral development

Acreage Status
- 71% HBP/HBU
- 29% Non-Producing
- 5% Drilled

Locations
- 93% Remaining Development
- 7% Drilled

Acreage Type
- 55% Federal
- 40% Fee
- 5% State

~290,000 Net Acres in Powder River Basin – 71% HBP/HBU
WHY WE LIKE THE PRB

- One of the largest, least-developed stacked pay opportunities in the country
  - 10+ prolific, proven formations
  - 1,800+ mi² of 3D seismic; 3,100' of whole core

- Prolific CHK producers from multiple zones
  - Sussex: 2,240 boe/d
  - Niobrara: 1,930 boe/d
  - Turner: 2,886 boe/d

- ~2.7 bboe gross recoverable resource
- ~2,700 operated potential locations
~531 bcf of 2018 gas hedged with swaps at an average price of $3.11
~47 bcf of 2018 gas hedged with collars at an average price of $3.00/$3.25
~18.9 mmbbl of 2018 oil hedged with swaps at an average price of $51.74
~1.8 mmbbl of 2018 oil hedged with three way collars at an average price of $39.15/$47.00/$55.00

(1) As of 10/30/17, using midpoints of total production from 11/2/2017 Outlook
DEBT MATURITY PROFILE

$9.2 billion
Principal balance @ 10/31/2017

(1) Amounts exclude outstanding balance under revolving credit facility
DEBT MATURITY PROFILE

$9.2 billion
Senior Notes & Term Loan (1)

7.11%
WACD

$643 million
Revolving Credit Facility (1)

2015 OUTLOOK

2016
$500
2017
$1,077
2018
$669
2019
$1,500
2020
$1,800
2021
$1,700
2022
$1,500
2023
$1,100
2024

2017 OUTLOOK

2015
$396
2016
$500
2017
$1,077
2018
$669
2019
$1,500
2020
$1,800
2021
$1,700
2022
$1,500
2023
$1,100
2024

(1) As of 10/31/2017
(2) Recognizes earliest investor put option as maturity for the 2.75% 2035, 2.5% 2037 and 2.25% 2038 Contingent Convertible Senior Notes
INDUSTRY LEADING CASH COSTS

- CHK remains a cash cost leader after halving costs over the last 5 years
- The next closest peer had >$2/bbl in additional costs in 2016

Sources: S&P Capital IQ, Company Filings
Cash Costs: Not including GP&T costs, Peer Group includes: APC, APA, COP, DVN, ECA, EOG, HES, MRO, MUR, NBL and OXY
CHESAPEAKE CAPITAL EFFICIENCY
RELENTLESS FOCUS ON CAPITAL DEPLOYED

2016 Proved F&D Costs (1)
6 mcf to 1 boe

2016 Proved F&D Costs (1)
15 mcf to 1 boe

~$2.35/boe

~$3.40/boe

Operational leadership and technical capabilities provide peer-leading cost management

(1) Source: 2016 10-K filings. Proved reserve F&D costs defined as the sum of the development and exploration costs divided by proved reserves added by extensions, additions and discoveries. Peer Group includes: APC, APA, COP, DVN, ECA, EOG, HES, MRO, MUR, NBL and OXY
CONTINUE TO DELIVER CAPITAL EFFICIENCIES
IN A RISING SERVICE COST ENVIRONMENT

*F&D Costs referenced in this chart are net capital costs divided by net EUR per well. Wells are binned by year in which they were TIL'd and then were averaged across that year.
CHESAPEAKE REPORTABLE SPILLS AND TRIR

Reportable Spills

>75% reduction

2013: 214
2014: 191
2015: 133
2016: 72
2017 through 10-30-17: 53

TRIR

>85% reduction

2013: 0.48
2014: 0.31
2015: 0.51
2016: 0.38
2017 through 10-30-17: 0.05
3Q’17 FINANCIAL AND OPERATIONAL RESULTS

Adjusted Earnings Per Share (1)
$0.12

Adjusted EBITDA (1)
$468 mm
11% year over year

Total Production Average
542 mboe/d
4% quarter over quarter

Current Oil Production (2)
99 mbo/d
compared to 86 mbo/d average in 3Q 2017

Liquids Mix (3)
27%
of total production

EBITDA Per Boe
31%
year over year

(1) See non-GAAP reconciliation on pages 28 and 29
(2) As of October 30, 2017
(3) Oil and NGLS collectively referred to as "liquids"
## CHESAPEAKE ENERGY CORPORATION
### RECONCILIATION OF ADJUSTED NET INCOME AVAILABLE TO COMMON STOCKHOLDERS
($ in millions except per share data)
(unaudited)

<table>
<thead>
<tr>
<th>THREE MONTHS ENDED:</th>
<th>September 30, 2017</th>
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<tbody>
<tr>
<td></td>
<td>$</td>
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<tr>
<td>Net loss available to common stockholders (GAAP)</td>
<td>$ (41)</td>
</tr>
<tr>
<td>Adjustments:</td>
<td></td>
</tr>
<tr>
<td>Unrealized losses on commodity derivatives</td>
<td>101</td>
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<tr>
<td>Provision for legal contingencies</td>
<td>20</td>
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<tr>
<td>Impairments of fixed assets and other</td>
<td>9</td>
</tr>
<tr>
<td>Net gains on sales of fixed assets</td>
<td>(1)</td>
</tr>
<tr>
<td>Losses on purchases or exchanges of debt</td>
<td>1</td>
</tr>
<tr>
<td>Income tax expense (benefit)&lt;sup&gt;(a)&lt;/sup&gt;</td>
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</tr>
<tr>
<td>Other</td>
<td>(6)</td>
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<tr>
<td><strong>Adjusted net income available to common stockholders&lt;sup&gt;(b)&lt;/sup&gt; (Non-GAAP)</strong></td>
<td>83</td>
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<tr>
<td>Preferred stock dividends</td>
<td></td>
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<tr>
<td><strong>Total adjusted net income attributable to Chesapeake&lt;sup&gt;(b)(c)&lt;/sup&gt; (Non-GAAP)</strong></td>
<td>$ 106</td>
</tr>
</tbody>
</table>

(a) Due to our valuation allowance position, no income tax effect from the adjustments has been included in determining adjusted net income.

(b) Adjusted net income (loss) available to common stockholders and total adjusted net income (loss) attributable to Chesapeake, both in the aggregate and per dilutive share, are not measures of financial performance under accounting principles generally accepted in the United States (GAAP), and should not be considered as an alternative to net income (loss) available to common stockholders or earnings (loss) per share. Adjusted net income (loss) available to common stockholders and adjusted earnings (loss) per share exclude certain items that management believes affect the comparability of operating results. The company believes these adjusted financial measures are a useful adjunct to earnings calculated in accordance with GAAP because:

(i) Management uses adjusted net income (loss) available to common stockholders to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies.

(ii) Adjusted net income (loss) available to common stockholders is more comparable to earnings 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.

(c) Our presentation of diluted adjusted net income (loss) per share excludes 206 million shares considered antidilutive when calculating diluted earnings per share in accordance with GAAP.
CHESAPEAKE ENERGY CORPORATION
RECONCILIATION OF ADJUSTED EBITDA
($ in millions)
(unaudited)

<table>
<thead>
<tr>
<th></th>
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</thead>
<tbody>
<tr>
<td>EBITDA</td>
<td>$345</td>
<td>$(865)</td>
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<tr>
<td><strong>Adjustments:</strong></td>
<td></td>
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</tr>
<tr>
<td>Unrealized (gains) losses on commodity derivatives</td>
<td>101</td>
<td>(163)</td>
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<tr>
<td>Unrealized losses on supply contract derivatives</td>
<td>—</td>
<td>280</td>
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<tr>
<td>Provision for legal contingencies</td>
<td>20</td>
<td>8</td>
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<tr>
<td>Impairment of oil and natural gas properties</td>
<td>—</td>
<td>497</td>
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<tr>
<td>Impairments of fixed assets and other</td>
<td>9</td>
<td>751</td>
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<tr>
<td>Net gains on sales of fixed assets</td>
<td>(1)</td>
<td>—</td>
</tr>
<tr>
<td>(Gains) losses on purchases or exchanges of debt</td>
<td>1</td>
<td>(87)</td>
</tr>
<tr>
<td>Net income attributable to noncontrolling interests</td>
<td>(1)</td>
<td>(1)</td>
</tr>
<tr>
<td>Other</td>
<td>(6)</td>
<td>1</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong>(a)</td>
<td>$468</td>
<td>$421</td>
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</table>

(a) Adjusted EBITDA excludes certain items that management believes affect the comparability of operating results. The company believes these non-GAAP financial measures are a useful adjunct to EBITDA because:

(i) Management uses adjusted EBITDA to evaluate the company's operational trends and performance relative to other oil and natural gas producing companies.

(ii) Adjusted EBITDA 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.

Accordingly, adjusted EBITDA should not be considered as a substitute for net income, income from operations or cash flow provided by operating activities prepared in accordance with GAAP.
### HEADQUARTERS
6100 N. Western Avenue
Oklahoma City, OK 73118
WEBSITE: [www.chk.com](http://www.chk.com)

### CORPORATE CONTACTS
**BRAD SYLVESTER, CFA**
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](mailto:ir@chk.com)

### PUBLICLY TRADED SECURITIES

<table>
<thead>
<tr>
<th>Description</th>
<th>CUSIP</th>
<th>Ticker</th>
</tr>
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<tbody>
<tr>
<td>7.25% Senior Notes due 2018</td>
<td>#165167CC9</td>
<td>CHK18A</td>
</tr>
<tr>
<td>3mL + 3.25% Senior Notes due 2019</td>
<td>#165167CM7</td>
<td>CHK19</td>
</tr>
<tr>
<td>6.625% Senior Notes due 2020</td>
<td>#165167CF2</td>
<td>CHK20A</td>
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<tr>
<td>6.875% Senior Notes due 2020</td>
<td>#165167BU0</td>
<td>CHK20</td>
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<tr>
<td>6.125% Senior Notes due 2021</td>
<td>#165167CG0</td>
<td>CHK21</td>
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<tr>
<td>5.375% Senior Notes due 2021</td>
<td>#165167CK21</td>
<td>CHK21A</td>
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<td>8.00% Senior Secured Second Lien Notes due 2022</td>
<td>#165167CQ8</td>
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<tr>
<td>4.875% Senior Notes due 2022</td>
<td>#165167CN5</td>
<td>CHK22</td>
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<tr>
<td>5.75% Senior Notes due 2023</td>
<td>#165167CL9</td>
<td>CHK23</td>
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<tr>
<td>8.00% Senior Notes due 2025</td>
<td>#165167CT2</td>
<td>N/A</td>
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<tr>
<td>8.00% Senior Notes due 2027</td>
<td>#165167CV7</td>
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<td>5.50% Contingent Convertible Senior Notes due 2026</td>
<td>#165167CR6</td>
<td>N/A</td>
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<td>2.25% Contingent Convertible Senior Notes due 2038</td>
<td>#165167CB1</td>
<td>CHK38</td>
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<td>4.5% Cumulative Convertible Preferred Stock</td>
<td>#165167842</td>
<td>CHK PrD</td>
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<td>5.0% Cumulative Convertible Preferred Stock (Series 2005B)</td>
<td>#165167834/</td>
<td>N/A</td>
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<tr>
<td>5.75% Cumulative Convertible Preferred Stock</td>
<td>#165167776/</td>
<td>N/A</td>
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<tr>
<td>5.75% Cumulative Convertible Preferred Stock (Series A)</td>
<td>#165167750</td>
<td>N/A</td>
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<tr>
<td>Chesapeake Common Stock</td>
<td>#165167107</td>
<td>CHK</td>
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**CHK**
LISTED
NYSE.

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**CORPORATE INFORMATION**

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